ATTACHMENT B

LBAO
06-2816
12/12/05

HB 1673-FN - FISCAL NOTE

AN ACT relative to the reduction of mercury emissions.

FISCAL IMPACT:

The Department of Environmental Services and the Public Utilities Commission stated this bill will have an indeterminable impact on state, county and local expenditures in future years. There will be no fiscal impact on state, county and local revenue.

METHODOLOGY:

The Department of Environmental Services (DES) and the Public Utilities Commission (PUC) state this bill intends to reduce mercury emissions from Merrimack Station, a coal burning electric generation plant in Bow, New Hampshire, currently owned by Public Service Company of New Hampshire (PSNH). As required, PSNH would install a wet flue desulphurization scrubber system at the plant. The technology would significantly reduce the plant's sulfur dioxide emissions and is expected to reduce the plant's mercury emissions by at least 80%. The equipment is to be installed no later than July 1, 2013. PSNH estimates that the installation will be at a cost not to exceed $250 million in 2013 dollars or $197 million in 2005 dollars. Any rate impact, therefore, would most likely be felt after the period of time identified in this fiscal note. In assessing the rate impact for the control equipment, the $250 million would be offset to some degree by savings resulting from PSNH's reduced need to purchase sulfur dioxide allowances, and additional revenues, as PSNH would be able to sell excess sulfur dioxide allowances if it achieves greater than 80% mercury reduction. Based on PSNH's estimates, the cost charged to the state, counties and localities in the first year of operation of the scrubber system would be approximately $1.9 million. After 10 years of operation, those entities would experience a net savings of approximately $500,000 per year. PSNH analyzed 3 different cost impact scenarios based on a low ($573/ton), moderate ($1,073/ton), and high ($1,573/ton) SO2 allowance price. DES states that the current price exceeds $1,400/ton. At the current price, over the 10-year time period, the project should result in net savings to PSNH.

HB 1673-FN – AS AMENDED BY THE HOUSE

22Mar2006... 0936h

2006 SESSION

06-2816
06/03

HOUSE BILL ***1673-FN***

AN ACT relative to the reduction of mercury emissions.

SPONSORS: Rep. Ross, Hills 3; Rep. Slocum, Hills 6; Rep. Kaen, Straf 7; Rep. Phinizy, Sull 5; Rep. Maxfield, Merr 6; Sen. Green, Dist 6; Sen. Johnson, Dist 2; Sen. Burling, Dist 5; Sen. Odell, Dist 8; Sen. Hassan, Dist 23

COMMITTEE: Science, Technology and Energy

ANALYSIS

This bill provides for an 80 percent reduction of mercury emissions from coal-burning power plants by requiring the installation of scrubber technology no later than July 1, 2013 and provides economic incentives for earlier installation and greater reductions in emissions.

Explanation: Matter added to current law appears in ***bold italics.***
Matter removed from current law appears [~~in brackets and struckthrough.~~]
Matter which is either (a) all new or (b) repealed and reenacted appears in regular type.

HB 1673-FN - AS AMENDED BY THE HOUSE
- Page 8 -

LBAO
06-2816
12/12/05

HB 1673-FN - FISCAL NOTE

AN ACT relative to the reduction of mercury emissions.

FISCAL IMPACT:

The Department of Environmental Services and the Public Utilities Commission stated this bill will have an indeterminable impact on state, county and local expenditures in future years. There will be no fiscal impact on state, county and local revenue.

METHODOLOGY:

The Department of Environmental Services (DES) and the Public Utilities Commission (PUC) state this bill intends to reduce mercury emissions from Merrimack Station, a coal burning electric generation plant in Bow, New Hampshire, currently owned by Public Service Company of New Hampshire (PSNH). As required, PSNH would install a wet flue desulphurization scrubber system at the plant. The technology would significantly reduce the plant's sulfur dioxide emissions and is expected to reduce the plant's mercury emissions by at least 80%. The equipment is to be installed no later than July 1, 2013. PSNH estimates that the installation will be at a cost not to exceed $250 million in 2013 dollars or $197 million in 2005 dollars. Any rate impact, therefore, would most likely be felt after the period of time identified in this fiscal note. In assessing the rate impact for the control equipment, the $250 million would be offset to some degree by savings resulting from PSNH's reduced need to purchase sulfur dioxide allowances, and additional revenues, as PSNH would be able to sell excess sulfur dioxide allowances if it achieves greater than 80% mercury reduction. Based on PSNH's estimates, the cost charged to the state, counties and localities in the first year of operation of the scrubber system would be approximately $1.9 million. After 10 years of operation, those entities would experience a net savings of approximately $500,000 per year. PSNH analyzed 3 different cost impact scenarios based on a low ($573/ton), moderate ($1,073/ton), and high ($1,573/ton) SO2 allowance price. DES states that the current price exceeds $1,400/ton. At the current price, over the 10-year time period, the project should result in net savings to PSNH.

ATTACHMENT C

The State of New Hampshire
Department of Environmental Services

Michael P. Nolin
Commissioner

January 12, 2006

The Honorable Lawrence C. Ross, Chairman
New Hampshire House of Representatives
Science, Technology and Energy Committee
Legislative Office Building, Room 304
Concord, New Hampshire 03301

Re: HB 1673 - An Act Relative to Emission Reduction Standards as Required by the Clean Power Act

Dear Chairman Ross and Members of the Committee:

Thank you for the opportunity to provide testimony in support of HB 1673 which seeks to reduce mercury emissions from affected fossil fuel burning power plants within New Hampshire. In accordance with the requirements of RSA 125-O, the *"Multiple Pollutant Reduction Program"*, the New Hampshire Department of Environmental Services (DES) made a recommendation to the Legislature on March 31, 2004 to place a cap on mercury emissions from these facilities.

Last year, the NH Senate passed SB 128 which contained similar mercury reductions as those contained in HB 1673. During committee hearings in the NH Senate and in the NH House, the public outcry and the expert testimony for controlling mercury emissions from our state's coal-fired power plants sent a clear message that significant mercury emission reductions must be made, but there were questions as how to best accomplish this task. Over the summer, PSNH in consultation with DES, performed tests with carbon injection control technology and researched the facility's ability to install wet scrubber technology. The results of this work led to the conclusion that while carbon injection can produce quick mercury emission reductions, the installation of the wet scrubber technology produces superior environmental benefits. HB 1673 is the product of months of discussions between Public Service Company of New Hampshire (PSNH), DES, the Office of Energy and Planning, the New Hampshire Governor's Office, and environmental groups that sought aggressive levels of mercury reductions while minimizing cost impacts on electrical ratepayers.

In order to best protect our citizens and environment from excess mercury emissions and to address the biological "hot spots" documented to exist within our state, we feel a successful mercury bill must meet three goals. First, it must reduce emissions as quickly as possible. Second, the chosen technology used must achieve the greatest mercury reduction technically feasible. And third, the technology must be implemented in a way that maintains our electrical reliability and affordability, without shifting production to upwind states.

HB 1673 meets these goals with the creative use of incentives and the aggressive application of technology. Early reduction will be achieved through additional testing of carbon injection technology with subsequent ongoing implementation on the most successful application of this technology. Critical to the success of this bill is the requirement that wet scrubber technology be installed on Merrimack Units 1 and 2

by July 1, 2013. The use of this technology not only reduces mercury very efficiently (greater than 90% in most applications), but it is highly effective in removing sulfur dioxide (SO_2) and small particles. This co-benefit of reducing three pollutants simultaneously with the same equipment reduces implementation costs by allowing PSNH to significantly reduce purchasing SO_2 emission allowances, saving greater than an estimated $25 million per year (2005$). Based on data shared by PSNH, the total capital cost for this full redesign will not exceed $250 million dollars (2013$) or $197 million (2005$), a cost that will be fully mitigated by the savings in SO_2 emission allowances. Finally, while the scrubber technology has been demonstrated to achieve higher levels of mercury reductions than initially called for in this bill, the bill contains a requirement that tightens the required reduction rate to the level that is actually achieved and is sustainable by the scrubber technology. Application of the requirements in this way reduces project risks while still achieving full environmental benefits.

Once completed, the mercury reduction requirements of HB 1673 should bring annual power plant emissions down to below 32 pounds per year and quite possibly below the 24 pound cap envisioned in the former SB 128. Further, HB 1673 is clearly more strict than the federal Clean Air Mercury Rule, that may have to be implemented here in New Hampshire with its own associated costs beginning in 2010, if no other alternative such as an enacted HB 1673 is proposed to EPA prior to November 2006. HB 1673 is consistent with state mercury programs in Connecticut, Massachusetts, New Jersey, and Indiana, as well as regional and national recommendations made by the State and Territorial Air Pollution Program Administrators and Association of Local Air Pollution Control Officials (STAPPA/ALAPCO), the Northeast States for Coordinated Air Use Management (NESCAUM), and the Ozone Transport Commission (OTC) for mercury Maximum Achievable Control Technology (MACT). Consistent with the amended SB 128, HB 1673 does not allow trading of mercury emission credits.

If passed, this bill will be technically challenging to implement because the existing configuration of the boilers, stacks, and air pollution control equipment at Merrimack Station does not easily lend itself to installation of additional equipment. Due to physical constraints, installation of additional equipment to optimally reduce mercury emissions would require major renovations. PSNH has worked hard to find creative solutions to these issues so that operations can be maintained while constructing and testing the required control equipment.

DES is committed to working with the Legislature to develop a prudent course of action to further reduce mercury emissions. Should any members have questions or need additional information regarding these recommendations, please feel free to contact Robert R. Scott, Air Resources Division Director, at 271-1088 or me at 271-2958.

Sincerely,

Michael P. Nolin
Commissioner

cc: HB 1673 Sponsors
Science, Technology and Energy Committee Members

The State of New Hampshire
Department of Environmental Services

Michael P. Nolin
Commissioner

April 11, 2006

The Honorable Bob Odell, Chairman
New Hampshire Senate
Energy and Economic Development Committee
Legislative Office Building, Room 304
Concord, New Hampshire 03301

ATTACHMENT #10

Re: HB 1673 - An Act Relative to Emission Reduction Standards as Required by the Clean Power Act

Dear Chairman Odell and Members of the Committee:

Thank you for the opportunity to provide testimony in support of HB 1673, which seeks to reduce mercury emissions from affected fossil fuel burning power plants within New Hampshire. HB 1673 is the result of several months of discussions between Public Service Company of New Hampshire (PSNH), DES, the Office of Energy and Planning, the New Hampshire Governor's Office, interested members of the General Court, and environmental advocacy organizations. DES's goal in these discussions was to seek aggressive levels of mercury reductions while minimizing cost impacts on electrical ratepayers. This bill achieves these goals, *and* provides additional environmental co-benefits of reduced local sulfur and particulate emissions.

While DES can appreciate the concerns some have expressed for greater reductions in a shorter timeframe, we remain steadfast that this bill represents a thoughtful balance of environmental and economic concerns. It delivers significant, yet practicably achievable reductions in a reasonable timeframe, and includes meaningful incentives for additional reductions beyond the bill's specified minimum and/or early action to reduce emissions. Eliminating flexibility in the required reductions and schedule will do little to provide actual environmental benefit, and yet may be detrimental to project financing We believe this package of an aggressive, yet realistic reduction target /schedule and economic incentives achieves our goals for meaningful environmental benefit, maintaining electricity supply stability, and reducing financial risk and subsequent ratepayer impact.

If passed, this bill will be technically challenging to implement because the existing configuration of the boilers, stacks, and air pollution control equipment at Merrimack Station does not easily lend itself to installation of additional equipment. Due to physical constraints, installation of additional equipment to optimally reduce mercury emissions would require major renovations. PSNH has worked hard to find creative solutions to these issues so that operations can be maintained while constructing and testing the required control equipment. We feel that 2013 represents a practicably achievable goal given these constraints. The specified technology has the potential to achieve reductions well beyond the minimum requirement of 80% from all affected sources (including PSNH's Schiller Station units). However, the bill contains significant incentives and safeguards to ensure higher reductions if achievable.

This bill ultimately results from the requirements of HB 284 (passed in the 2002 session), commonly referred to as the New Hampshire Clean Power Act. In accordance with the requirements of RSA 125-O (as established by HB 284) the *"Multiple Pollutant Reduction Program"*, the New Hampshire Department of Environmental Services (DES) made a recommendation to the Legislature on March 31, 2004 to place a cap on mercury emissions from these facilities. In response, last year, the NH Senate passed SB 128 which contained similar mercury reductions as those contained in HB 1673.

During committee hearings in both the Senate and in the House, the public outcry and the expert testimony for controlling mercury emissions from our state's coal-fired power plants sent a clear message that significant mercury emission reductions must be made. There were questions, however, as to how best to accomplish this task. Over the summer, PSNH in consultation with DES, performed tests with carbon injection control technology and researched the facility's ability to install wet scrubber technology. The results of this work led to the conclusion that while carbon injection can produce quick mercury emission reductions, the installation of the wet scrubber technology produces superior environmental benefits at a lower overall cost

In order to best protect our citizens and environment from excess mercury emissions and to address the biological "hot spots" documented to exist within our state, we feel a successful mercury bill must meet three goals. First, it must reduce emissions as quickly as possible. Second, the chosen technology used must achieve the greatest mercury reduction technically feasible. And third, the technology must be implemented in a way that maintains our electrical reliability and affordability, without shifting production to upwind states.

HB 1673 meets these goals with the creative use of incentives and the aggressive application of technology. Early reduction will be achieved through additional testing of carbon injection technology with subsequent ongoing implementation on the most successful application of this technology. Critical to the success of this bill is the requirement that wet scrubber technology be installed on Merrimack Units 1 and 2 by July 1, 2013. The use of this technology not only reduces mercury very efficiently (potentially greater than 90% in most applications), but it is highly effective in removing sulfur dioxide (SO_2) and small particles. This co-benefit of reducing three pollutants simultaneously with the same equipment reduces implementation costs by allowing PSNH to significantly reduce purchasing SO_2 emission allowances. Based on data shared by PSNH, the total capital cost for this full redesign will not exceed $250 million dollars (2013$) or $197 million (2005$), a cost that will be fully mitigated by the savings in SO_2 emission allowances. Finally, while the scrubber technology has been demonstrated to achieve higher levels of mercury reductions than initially called for in this bill, the bill contains a requirement that tightens the required reduction rate to the level that is actually achieved and is sustainable by the scrubber technology. Application of the requirements in this way reduces project risks while still achieving full environmental benefits.

Further, HB 1673 is clearly more strict than the federal Clean Air Mercury Rule, that may have to be implemented here in New Hampshire with its own associated costs beginning in 2010, if no other alternative such as an enacted HB 1673 is proposed to EPA prior to November 2006. HB 1673 is consistent with state mercury programs in Connecticut, Massachusetts, New Jersey, and Indiana, as well as regional and national recommendations made by the State and Territorial Air Pollution Program Administrators and Association of Local Air Pollution Control Officials (STAPPA/ALAPCO), the Northeast States for Coordinated Air Use Management (NESCAUM), and the Ozone Transport Commission (OTC) for mercury Maximum

Achievable Control Technology (MACT). Consistent with the amended SB 128, HB 1673 does not allow trading of mercury emission credits.

DES is committed to working with the Legislature to develop a prudent course of action to further reduce mercury emissions. Should your committee members have questions or need additional information regarding these recommendations, please feel free to contact Robert R. Scott, Air Resources Division Director, at 271-1088.

Sincerely,

Michael Wales, Asst. Comm.

for Michael P. Nolin
Commissioner

cc: HB 1673 Sponsors
Senate Energy and Economic Development Committee

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-02
Dated: 06/18/2012
Q-TC-003-SP01
Page 1 of 41

Witness: William H. Smagula, Terrance J. Large
Request from: TransCanada

Question:
Please provide copies of any and all documents that PSNH or any of its employees, officials, representatives, agents or lobbyists provided to DES, any legislator or any state official to support the statement in DES Commissioner Michael Nolin's January 12, 2006 letter to the House Science, Technology & Energy Committee in support of HB 1673 to the effect that the costs of the scrubber will be fully mitigated by the savings in SO2 emission allowances.

Response:
Please see the attached documents. Also see the response to TC-02, Q-TC-003.

NH Senate Bill 128 Proposed Amendment Framework Key Talking Points

October, 2005

Draft
for Discussion Purposes

Scrubber Technology

- Best known commercially available technology today to remove mercury
- Installation price tag not to exceed $250M
- Scrubber Technology addresses multi-pollutant strategy by reducing other emissions, in particular SO2, achieving an environmentally superior and more cost effective solution
- Coal-fired plant owners required to remove a minimum of 80% of total mercury input as measured at coal fired boilers
- Scrubber project has a long lead time to permit, construct and test before operations; therefore incentives have been created to expedite in-service date insofar as possible
- Incentives have been created to encourage reductions of greater than 80%

Costs

- Total project capital costs should not exceed $250M (in year 2013 dollars)
- Amortization of the investment and operational costs will be offset by reductions in SO2 Allowance purchases required by NH Clean Power Act
- Costs in early years following installation are further reduced by incentive provisions of NH Clean Power Act for SO2 reductions

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-04
Dated: 08/31/2012
Q-TC-013
Page 1 of 5

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference page 16, line 10, of Mr. Smagula's June 15, 2012 prefiled testimony in this docket, please provide copies of any and all "published cost statements" that have been issued in connection with the scrubber project since its inception.

Response:
The Clean Air Project Team published three cost estimates. These updated estimates are presented in the company's Form 10-Q quarterly filings attached below. The Clean Air Project Team presented a site specific cost estimate of $457 million in May 2008 which was approved by NU's Board of Trustees in July 2008. The Clean Air Project Team updated the estimated project cost to $430 million in the second half of 2010. A third and final update in the first half of 2011 estimated a project cost of $420 million.

10-Q 1 june2008form10qfinal.htm FORM 10-Q

Northeast
Utilities System

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 2008

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	02-0181050
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

Our second major project of NEEWS is the Interstate Reliability Project, which is being designed and built in coordination with National Grid. NU's share of this project includes a 40-mile 345 KV line from Lebanon, Connecticut to the Connecticut-Rhode Island border where it would connect with enhancements National Grid is designing. We expect NU's share of this project to cost approximately $250 million, and CL&P plans to file siting applications with Connecticut by the end of 2008 with construction beginning in 2010. We expect the project to be placed in service as early as late 2012.

The third part of NEEWS is the Central Connecticut Reliability Project, which involves construction of a new line from Bloomfield, Connecticut to Watertown, Connecticut. This line would provide us with another 345 KV connection to move power into southwest Connecticut, where approximately half of the state's electricity is consumed. The timing of this project would be six to twelve months behind the other two projects, and CL&P expects to initiate the siting process in mid-2009 with construction beginning in 2011. The project is expected to be placed in service in 2013 with a cost of approximately $315 million.

Included as part of NEEWS are approximately $210 million of reliability related expenditures, many of which may be incurred in advance of the three major projects. CL&P and WMECO expect to begin filing siting applications related to some of these expenditures later in 2008.

During the siting approval process, state regulators may require changes in configuration to address local concerns which could increase construction costs. Our current design for NEEWS does not contemplate any underground 345 KV lines. Building 345 KV lines underground would increase total costs, and our estimate could be increased during the siting approval process.

Distribution and Generation Segment: We now project a total of approximately $541 million of distribution and generation segment capital expenditures for 2008. A summary of these estimated capital expenditures for the regulated companies' distribution and generation segments by company for 2008 is as follows (millions of dollars):

CL&P	$ 299
PSNH	167
WMECO	35
Yankee Gas	40
Totals	$ 541

On February 15, 2008, Yankee Gas and NRG Energy, Inc. entered into a settlement agreement, which among other things, enabled the recovery of approximately $17.5 million of capital costs and expenses incurred by Yankee Gas related to an NRG subsidiary's generating plant construction project that has ceased. The previously reported Yankee Gas capital expenditures projection for 2008 decreased from $56 million to approximately $40 million primarily as a result of the accounting adjustment recorded in the first half of 2008 related to the settlement agreement.

A summary of distribution and generation segment capital expenditures by company in the first half of 2008 and 2007 is as follows (millions of dollars):

	For the Six Months Ended June 30,	
	2008	2007
CL&P	$ 131.6	$ 128.0
PSNH	69.4	56.3
WMECO	15.9	16.4
Yankee Gas	6.2	29.1
Other	0.3	0.1
Totals	$ 223.4	$ 229.9

The first half of 2008 capital expenditures at Yankee Gas were reduced by the $17.5 million accounting adjustment described above, while the first half of 2007 capital expenditures included $9.3 million spent on its $108 million liquefied natural gas (LNG) storage and production facility in Waterbury, Connecticut, which was placed in service in July 2007.

As mandated by New Hampshire statute, PSNH plans to install a wet scrubber at its coal-fired, two-unit base load Merrimack plant in Bow, New Hampshire (Clean Air Project). PSNH now estimates that the Clean Air Project will cost approximately $457 million, compared with its initial estimate of $250 million, which will be recovered through PSNH generation rates under the statute. This revised estimate includes significant increases in the prices for materials, construction services and engineering services required to design and build the scrubber and associated plant. The Clean Air Project is expected to reduce the two units' mercury emissions by

approximately 85 percent and sulfur dioxide emissions by more than 90 percent, as well as allow PSNH to avoid the purchase of 30,000 sulfur dioxide credits required to be purchased annually. PSNH expects to start construction on this project in 2009, and under

New Hampshire statute, the scrubber must be operational by July 2013. The first half of 2008 capital expenditures at PSNH include $5.8 million in costs related to this project.

Strategic Initiatives: We are evaluating certain development projects that would benefit our customers, such as new regulated generating facilities, investments in wide-spread advanced metering infrastructure (AMI) systems, and transmission projects to better interconnect new renewable generation in northern New England and Canada with southern New England, as well as interconnections within New Hampshire. The estimated capital expenditures discussed above do not include expenditures related to any of these strategic initiatives.

Among the projects we are evaluating is construction of new transmission upgrades in northern New Hampshire to support the addition of 400 MW of new renewable generation (including potential wind and biomass generation), along with other upgrades to the New England transmission system. As our next step in the process of identifying potential solutions to the region's energy and environmental needs, on March 31, 2008, we filed a formal request with ISO-NE to analyze potential increases in the North-South high voltage power transfer capacity from New Hampshire into Massachusetts to deliver additional power from renewable and low-carbon emitting resources in northern New England and Canada to southern New England. We requested that ISO-NE analyze the best methods of increasing that capability by 1,500 MW to 2,500 MW. We expect the economic study of some of the above initiatives by ISO-NE to be completed in 2009.

Transmission Rate Matters and FERC Regulatory Issues

CL&P, PSNH and WMECO and most other New England utilities, generation owners and marketers are parties to a series of agreements that provide for coordinated planning and operation of the region's generation and transmission facilities and the market rules by which these parties participate in the wholesale markets and acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent from all market participants, has served as the Regional Transmission Organization (RTO) for New England since February 1, 2005. ISO-NE works to ensure the reliability of the New England transmission system, administers the independent system operator tariff (ISO Tariff), subject to FERC approval, oversees the efficient and competitive functioning of the regional wholesale power market and determines which portion of the costs of our major transmission facilities are regionalized throughout New England.

Transmission - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of our wholesale transmission revenues are collected under the ISO-NE FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes RNS and LNS rate schedules to recover fees for transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, which we administer, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 50 percent of the CWIP that is included in rate base on the remaining three southwest Connecticut projects (Middletown-Norwalk, Glenbrook Cables and Long Island Replacement Cable). The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that we recover all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to customers. In the second quarter of 2008, under the terms of Tariff No. 3, NU recovered $23 million of the 2007 underrecovery and deferred an underrecovery of $21 million for differences in the second quarter of 2008. As of June 30, 2008, the LNS rates were in a total underrecovery position of approximately $34 million, which will fluctuate period to period. On June 1, 2008, the RNS rate and LNS rate were increased to reflect true-ups for historical costs and to reflect forecasted capital expenditures. We believe that these rates will provide us with timely recovery of transmission costs, including costs of our major transmission projects.

FERC ROE Decision: As a result of an order issued by the FERC on October 31, 2006 relating to incentives on new transmission facilities in New England (Initial ROE Order), we recorded an estimated regulatory liability for refunds in 2006. In 2007, we completed the customer refunds that were calculated in accordance with the compliance filing required by the Initial ROE Order, and refunded amounts to regional, local and localized transmission customers.

On March 24, 2008, the FERC issued an order on rehearing of its Initial ROE Order. In the rehearing order, the FERC, among other things, increased the base ROE on transmission projects for the transmission owners from the 10.2 percent allowed in the Initial ROE Order to 10.4 percent effective February 1, 2005 and reaffirmed its Initial ROE Order increasing the ROE by 74 basis points for the period beginning November 1, 2006 in recognition of higher bond yields. The rehearing order also modified the FERC's Initial ROE Order provision allowing 100 additional basis points for new transmission projects that are built as part of the ISO-NE RSP by limiting the 100 basis points adder solely to projects that are "completed and on line" by December 31, 2008. In order to receive

THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 11-250

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Investigation of Merrimack Station Scrubber Costs and Cost Recovery

PREFILED TESTIMONY OF MICHAEL E. HACHEY
ON BEHALF OF TRANSCANADA POWER MARKETING LTD. AND
TRANSCANADA HYDRO NORTHEAST INC.

ATTACHMENT 6

DE 03-108 – September 2, 2008 letter from Gary Long and PSNH report to PUC – link:
http://www.puc.state.nh.us/Regulatory/Docketbk/2008/08-103.htm
September 2, 2008 entry in docket

State of New Hampshire

GENERAL COURT

CONCORD

MEMORANDUM

DATE:	November 1, 2008
TO:	Honorable John H. Lynch, Governor Honorable Terie Norelli, Speaker of the House Honorable Sylvia B. Larsen, President of the Senate Michael York, State Librarian Chairman Thomas B. Getz, Public Utilities Commission
FROM:	Representative Naida L. Kaen, Chair
SUBJECT:	Annual Report on RSA 374-F:5, HB 1392, Ch. 129:2, Laws of 1996

Pursuant to Chapter 129:2, Laws of 1996, enclosed please find the Annual Report of the Electric Utility Restructuring Legislative Oversight Committee.

If you have any questions or comments regarding this report, please do not hesitate to contact me.

NLK:ta
Enclosure

cc: Committee Members
Joel Anderson, Committee Researcher

2008 Annual Report of the

Legislative Oversight Committee on Electric Utility Restructuring

(RSA 374-F:5)

November 1, 2008

Committee Members

Rep. Naida Kaen, Chair	Sen. Lou D'Allesandro
Rep. John Thomas	Sen. Deborah Reynolds
Rep. Michael Kaelin	Sen. Martha Fuller Clark
Rep. Jacqueline Cali-Pitts	Sen. Robert Letourneau
Rep. Gene Andersen	Sen. Peter Burling
Rep. Richard Barry	Sen. Bob Odell
Rep. Ryan Hansen	Sen. John Barnes

The committee met on June 18, 2008 to receive a report, as required by law (RSA 125-O:13), regarding progress toward achieving mercury reductions at the coal-fired plant, Merrimack Station, which is owned and operated by Public Service Company of New Hampshire (PSNH), a wholly-owned subsidiary of Northeast Utilities(NU) which is headquartered in Connecticut. A similar meeting had been held at the conclusion of the 2007 legislative session at which members had been briefed regarding the history of air pollution control at PSNH's power plants, including the passage of HB 1673 in 2006, which set the requirement that installation of a permanent scrubber was to be achieved by 2013, and which provided incentives for PSNH to achieve early reductions.

On June 18, 2008 the committee heard from PSNH regarding the experimental activated carbon injection project funded through a grant from the Department of Energy (DOE). This project had been undertaken in the hope of achieving early reductions of mercury prior to the 2013 scrubber installation. It was explained that two problems were interfering with achievement of the hoped for 80% reduction, and that nothing greater than a 50% reduction of mercury emissions was likely. As each particular plant and its inputs of coal are unique, it had been impossible to predict the results in advance. In the case of Merrimack station, the injection of two materials seemed to work best for mercury reduction, but resulted in unacceptable operational problems including clogging in parts of the boiler and smoldering in the precipitator.

PSNH thus concluded that proceeding with the scrubber installation is the only remaining remedy. It was mentioned that there were some difficulties identified by the project manager, URS (previously known as Washington Group), relating to the fact that the two units "MK1" and "MK2" are so different in size, i.e. "mismatched units". There

was no cost information provided to indicate a significant departure from the projections made in 2006. PSNH reported that project costs would be updated with the review of major equipment bids.

Attached is the handout that PSNH provided the Committee members at the June 18th meeting.

Respectfully submitted,

Naida Kaen
JA

Rep. Naida Kaen, Chair
On behalf of the Committee

PSNH Legislative Update- June 18, 2007

Update relative to the reduction of mercury emissions at PSNH Coal Fired power plants as outlined in HB1673.

As required by HB 1673 (RSA 125-O:13 Compliance- Paragraph IX) PSNH shall report by June 30, 2007 to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on the progress and status of:

1) Achieving early reductions in mercury emissions:

DOE Mercury Reduction Project at Merrimack Unit 2

- **Program Schedule Fall 06 – Spring 08**
  - Completed Parametric Testing Nov 2006
  - Completed Long Term Testing April 1, 2008
  - Used various combinations of sorbents to assess effectiveness
  - Varied rates of injections
  - Varied location of injection points
- **Long term Test Evaluations**
  - Long term test – Fall 2007 thru March 2008
  - Equipment performance
  - Balance of Plant Issues
  - Mercury Removal Performance
- **Measurement tools and methods**
  - Completed sorbent trap measurements
  - Installed and monitored Hg CEMs
- **Results of Parametric tests**
  - Initial injection plan 10 – 30%
  - Enhanced injection resulted in a wide variation of results
  - Sustainable results will depend on the ability to resolve balance of plant issues

2) Installing and operating the scrubber technology:

CLEAN AIR PROJECT UPDATE

- **Engineering**
  - Projects defined in 5 major components
  - Specifications developed for 4 key components
- **Commercial and Purchasing** – URS
  - Program Manager Hired Sept 2007
  - Scrubber Island and Chimney proposals are in negotiations
  - Vendor Proposals requested and received for Wastewater Treatment Facility and Material Handling System
- **Review, Permits and Approvals**
  - NHDES – May 12 presentation
  - Temporary Permit expected October 2008
  - Town of Bow –Local permitting
  - Regional Planning Commission
- **Site work**
  - Existing oil tank removed
  - Site surveys and studies completed
  - Warehouse construction underway
  - On-site engineering facilities completed
- **Schedule and Costs**
  - Tie-ins: MK#1 Fall 2012, MK#2 Spring 2013
  - Project Costs will be updated with review of major equipment bids

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request STAFF-01

Dated: 12/30/2011
Q-STAFF-012
Page 1 of 75

Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

Question:
Please provide copies of all reports to the Legislative Oversight Committee on Electric Restructuring and other persons pursuant to the requirements of RSA 125-O:13,IX.

Response:
The requested information is attached.

PSNH Legislative Update- June 18, 2008*

Update relative to the reduction of mercury emissions at PSNH Coal Fired power plants as outlined in HB1673.

As required by HB 1673 (RSA 125-O:13 Compliance- Paragraph IX) PSNH shall report by June 30, 2007 to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on the progress and status of:

1) Achieving early reductions in mercury emissions:

DOE Mercury Reduction Project at Merrimack Unit 2

- **Program Schedule Fall 06 – Spring 08**
  - Completed Parametric Testing Nov 2006
  - Completed Long Term Testing April 1, 2008
  - Used various combinations of sorbents to assess effectiveness
  - Varied rates of injections
  - Varied location of injection points
- **Long term Test Evaluations**
  - Long term test – Fall 2007 thru March 2008
  - Equipment performance
  - Balance of Plant Issues
  - Mercury Removal Performance
- **Measurement tools and methods**
  - Completed sorbent trap measurements
  - Installed and monitored Hg CEMs
- **Results of Parametric tests**
  - Initial injection plan 10 – 30%
  - Enhanced injection resulted in a wide variation of results
  - Sustainable results will depend on the ability to resolve balance of plant issues

2) Installing and operating the scrubber technology:

CLEAN AIR PROJECT UPDATE

- **Engineering**
  - Projects defined in 5 major components
  - Specifications developed for 4 key components
- **Commercial and Purchasing**
  - Program Manager Hired Sept 2007
  - Scrubber Island and Chimney proposals are in negotiations
  - Vendor Proposals requested and received for Wastewater Treatment Facility and Material Handling System
- **Review, Permits and Approvals**
  - NHDES – May 12 presentation
  - Temporary Permit expected October 2008
  - Town of Bow –Local permitting
  - Regional Planning Commission
- **Site work**
  - Existing oil tank removed
  - Site surveys and studies completed
  - Warehouse construction underway
  - On-site engineering facilities completed
- **Schedule and Costs**
  - Tie-ins: MK#1 Fall 2012, MK#2 Spring 2013
  - Project Costs will be updated with review of major equipment bids

*year corrected to reflect June 2008 update

PSNH Legislative Update- June 26, 2007

Update relative to the reduction of mercury emissions at PSNH Coal Fired power plants as outlined in HB1673.

As required by HB 1673 (RSA 125-O:13 Compliance- Paragraph IX) PSNH shall report by June 30, 2007 to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on the progress and status of:

1) Achieving early reductions in mercury emissions:

DOE Mercury Reduction Project at Merrimack Unit 2

- **Parametric Testing**
  - September – November 2006
  - Used temporary equipment set-ups
  - Used various combinations of sorbents to assess effectiveness
  - Varied rates of injections
  - Varied location of injection points
- **Optimum plan for long term test**
  - Engineered and purchased equipment for long-term test and post DOE use
  - Installed and commissioned new equipment
  - Long term test – June to November 2007
- **Measurement tools and methods**
  - Completed sorbent trap measurements
  - Installed and monitored Hg CEMs
  - Identified testing methods for long-term test including new EPA methods
- **Results of Parametric tests**
  - Initial injection plan 10 – 30%
  - Enhanced injection plan scattering of individual points between 30 – 60%
  - Sustainable results to be determined during long-term test

2) Installing and operating the scrubber technology:

CLEAN AIR PROJECT UPDATE

- **Engineering**
  - Specifications developed for key components
  - Possible Site plan layouts developed
  - Equipment options identified
  - Vendor lists and contacts established
  - Industry impact of high number of scrubber installations analyzed
- **Commercial and Purchasing**
  - Contract Strategy determined and approved
  - Program Manager Specification written
  - Program Manager out to Bid
- **Permits and Approvals**
  - Temporary Air Permit Application submitted to NHDES-ARD June 7, 2007
  - Town of Bow presentations and submittals underway
  - Company financing approvals initiated
- **Site work**
  - Existing oil tank removal completed
  - Site surveys completed
  - South Yard studies completed

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-04
Dated: 08/31/2012
Q-TC-017

Witness: **William H. Smagula**
Request from: **TransCanada**

Question:
Please provide a copy of the July 2008 PowerAdvocate report for PSNH referenced on page 2 of attachment WHS-3.

Response:
Attached is the requested 2008 PowerAdvocate report.

Merrimack Station Clean Air Project
Cost Estimate Analysis

June 17th 2008

DRAFT

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PowerAdvocate
Real Results for a Complex World

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Clean Air Project Cost Estimate Analysis

Summary

As part of PowerAdvocate's analysis of the Project Cost Estimate for Merrimack Station's Clean Air Project (CAP), site specific factors surrounding the design and construction of the scrubber specific to this installation were scrutinized, along with the market forces associated with capital construction projects in general and retrofit scrubber projects in particular. The objective of this analysis is twofold:

1. Explain why Merrimack Station's CAP's cost estimate is on the high end of the cost per kilowatt range for a complete FGD retrofit relative to similar FGD retrofit projects.
2. Discuss market forces behind capital construction project cost increases in the utility industry, including retrofit scrubber projects, to better understand why Merrimack Station's CAP cost estimate has increased from an estimated $250M in 2006 to an excess of $350M today.

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I. Site Specific Factors

It should be clearly noted that the majority of FGD projects, for sulfur and mercury scrubbers alike, exhibit substantial economies of scale once the absorber size reaches approximately 550MW. The costs for the majority of a project, both in procurement and construction, increase exponentially for scrubber capacities that are less than this benchmark. It is not uncommon to find a per-kilowatt cost for a 200MW absorber to be over twice the price of a 600MW unit.

Based on the most recent estimate provided by URS (Estimate), the direct cost per kilowatt for the installed Wet FGD (WFGD) is approximately $775 based upon a nominal station capacity of 458MW. Since this cost is above industry benchmarks, PowerAdvocate analyzed different reasons for the discrepancy and created adjustment factors to bring the scope of Merrimack's CAP more in line with other similar projects. This approach allowed for a more realistic "apples to apples" comparison. Through this comparison, PA determined that a levelized cost for the CAP is approximately $580/kW, or a 25% reduction from per-kW cost of $775. This adjusted cost is based upon applying assumed Impact percentages (i.e. FGD Impact % = 10%) to the Estimate cost components for each of the site specific components, which were then totaled and subsequently subtracted from the Estimate resulting in the equalized $/kW. This adjusted cost falls within the benchmark range for projects of this size as shown below in Table 2 and Figure 1, where market data indicates that construction costs for wet FGD systems in the US have risen dramatically over the past several years and are currently in the range between $250/kW and $654/kW (median $467/kW) for similar sized systems.

The following table shows factors that were considered.

Site Specific Component	Significant Impact?	Discipline/Subsystem Affected
Mercury Scrubber	Yes	BOP Engineering/FGD
Asymmetrical Units to Single Absorber	Yes	BOP/FGD
Station Site Constraints	Yes	BOP/MH
All-Subcontract Construction Basis	Yes	BOP Construction
Foundations	No	N/A
Limited Highway Access	No	N/A
Pressurized Cyclone Boiler	Yes	BOP Engineering

Table 1. CAP site specific analysis components

Further explanation of the methodology utilized in determining the costs (as shown in the attached *Design Differences* spreadsheet, Appendix 1.1) associated with each factor are described below. This list is not considered all-inclusive. A conservative approach was employed due to other design variations for this system that could not be quantified:

Mercury Scrubber Merrimack's CAP is designed specifically for Mercury (Hg) removal with an added benefit of further reducing SO_2 emissions. Most WFGD scrubbers in use and under construction today are designed primarily for SO_2 capture. The design differences for this type of approach include additional Hg oxidation controls/consideration, increased surface area of absorber bed, and increased contact time with flue gas to allow for full reaction.

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Asymmetrical Units Combining into a Single Scrubber This is the largest design difference between Merrimack Station's absorber and majority of similar sized systems in the industry. Since Unit 2 is over twice the power of Unit 1, the flows and capacities of the duct and induced draft system are different. In addition there are design aspects of balancing unequal flows into the same duct channel that set this project apart from many others.

Station Site Constraints Merrimack Station is located on the Merrimack River in central New Hampshire. The eastern edge of the main plant is located within ±200 feet of the river and there are several railroad spurs cutting North-South across the station's footprint. In addition, the Material Handling design is slated to extend from the coal yard to the North, down the East side of the power block to the absorber building to the Southeast. This will require construction of components for the MH and other systems to occur in the restricted space of the riverbank area directly above a rail spur.

All-Subcontract Construction Basis The CAP will be constructed without any direct hire labor from the EPCm. All aspects of the project will be completed in Contract Packages utilizing a General President's Project Maintenance Agreement (GPPMA) or National Maintenance Agreement (NMA) with primarily local union personnel. This approach simplifies management to a degree but also incurs a significant percentage mark-up to cover each subcontractor's overhead and profit.

Pressurized Cyclone Boiler Both coal combustion units at Merrimack Station are of the pressurized cyclone type. This type of combustor can produce higher temperatures and flows than similar pulverized coal combustors. Due to these operating characteristics, further engineering may be required to ensure proper long-term operation.

Each of these factors contributes to the "uniqueness" of the CAP project when compared to a more standard Wet FGD system. When these attributes are summarized and used to levelize the per-kilowatt cost, Merrimack Station's CAP is more in line with other projects of similar size and scope.

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Other FGD Retrofits	Capacity (MW)	Project Cost[1] ($)	$/kW	Number of Units[2]	In Service Year
Project 1	600	$150,000,000	$250	1	2009
Project 2	557	$148,000,000	$266	1	2008
Project 3	446	$141,400,000	$317	1	2009
Project 4	364	$121,600,000	$334	1	2010
Project 5	556	$188,000,000	$338	1	2008
Project 6	556	$189,000,000	$340	1	2008
Project 7	576	$218,900,000	$380	1	2009
Project 8	305	$127,900,000	$419	1	2009
Project 9	576	$263,800,000	$458	1	2009
Project 10	390	$185,600,000	$476	1	2009
Project 11	416	$198,000,000	$476	1	2009
Project 12	550	$261,700,000	$476	1	2009
Project 13	571	$280,400,000	$491	1	2009
Project 14	363	$209,800,000	$578	1	2009
Project 15	405	$234,100,000	$578	1	2009
Project 16	320	$195,100,000	$610	1	2009
Project 17	500	$304,900,000	$610	1	2009
Project 18	350	$228,900,000	$654	1	2010
Merrimack Station	**458**	**$354,931,538**	**$775**	**2**	2012

Table 2. Projected Completion Costs by $/kW

1. Different retrofit FGD projects may have different components (i.e. PJFF, SCR, PAC, ESPs) included or omitted affecting the final cost. There are other inputs to project costs including geological and bathymetric factors as well as site-specific requirements such as the length of the material handling system or pier work. In addition, Owner's Costs have also been excluded from this price.
2. Number of combustion units serving a single absorber.

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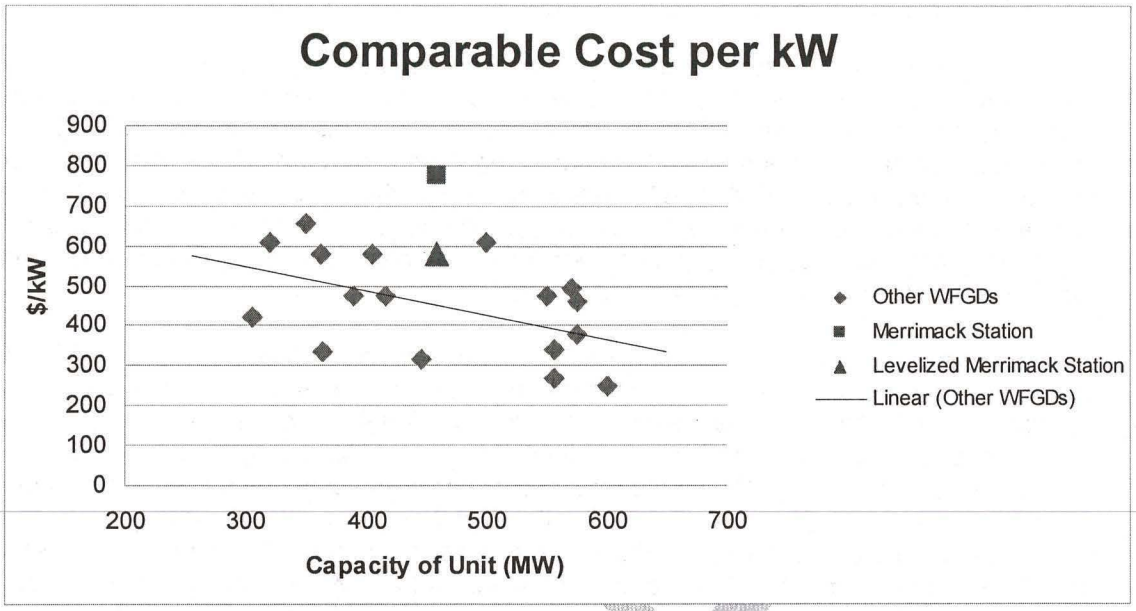

Figure 1. Levelized Cost for Projects of Comparable Size

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II. Capital Construction Project Market Trends[1]

Capital construction costs for new generation and transmission projects remain at historic levels with no clear understanding of whether or not we have reached the peak due to the recent volatility of costs associated with the supply market. This fact coupled with the increased uncertainty around projected carbon regulations and the effects of a tight labor market, the utility industry finds itself in a period of time where there seems to be no good indicator for investment decisions. Costs have, in many cases, escalated more than 75% since the year 2000, and ongoing pressure from global players such as China, India, and the Middle East may only accelerate that escalation.

Capital construction costs for retrofit scrubber projects have increased by a modest 7.8% within the last year, with only a 1.0% increase occurring between the third and fourth quarters of 2007. Although the Construction Labor (78% increase since 2000) and Engineering & Project Management (44% increase since 2000) categories combine to encompass approximately 47% of the total retrofit costs, the cost driver behind the large project increase is the Absorber (FGD Island), which has seen a 217% increase over the same period. The demand for absorbers has increased dramatically over the last few years as utilities perform retrofit projects to meet ongoing regulatory standards have to compete with the increase in new coal plants domestically and internationally. Given this, PowerAdvocate forecasts an average increase of 6.2% per year for the next five years for retrofit scrubber project costs, which is slightly down from the 9.5% annualized historical escalation rate over the past eight years.

As shown below in Table 3 and Figure 2, when this escalation forecast factor is applied to the other FGD retrofits with earlier in service dates (2008 thru 2010), the Adjusted Project Costs ($) and Adjusted $/kW increase thus increasing the median $/kW to be more in line with Merrimack Station's $580/kW. Prior to the escalation adjustment, the comparable projects ranged between $250/kW and $654/kW (median $467/kW); following the escalation adjustment, the comparable projects ranged between $299/kW and $738/kW (median $570/kW), a 22% increase. This escalation adjustment further explains why Merrimack Station's CAP's cost estimate is on the on the high end of the cost per kilowatt range for a complete FGD retrofit relative to similar FGD retrofit projects when you consider both the uniqueness factors and the forecast cost escalation associated with retrofit scrubber project costs.

DRAFT

[1] PowerAdvocate PADatasource Market Report, Construction Cost Indices for the US Power Market, Spring 2008

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Other FGD Retrofits	Capacity (MW)	Project Cost ($)	$/kW	Number of Units	In Service Year	Adjusted Project Cost ($)[1]	Adjusted $/kW[2]
Project 1	600	$150,000,000	$250	1	2009	$179,665,549	$299
Project 2	557	$148,000,000	$266	1	2008	$188,260,749	$338
Project 3	446	$141,400,000	$317	1	2009	$169,364,724	$380
Project 4	364	$121,600,000	$334	1	2010	$137,145,830	$377
Project 5	556	$188,000,000	$338	1	2008	$239,142,033	$430
Project 6	556	$189,000,000	$340	1	2008	$240,414,065	$432
Project 7	576	$218,900,000	$380	1	2009	$262,191,925	$455
Project 8	305	$127,900,000	$419	1	2009	$153,194,825	$502
Project 9	576	$263,800,000	$458	1	2009	$315,971,813	$549
Project 10	390	$185,600,000	$476	1	2009	$222,306,173	$570
Project 11	416	$198,000,000	$476	1	2009	$237,158,525	$570
Project 12	550	$261,700,000	$476	1	2009	$313,456,495	$570
Project 13	571	$280,400,000	$491	1	2009	$335,854,800	$588
Project 14	363	$209,800,000	$578	1	2009	$251,292,215	$692
Project 15	405	$234,100,000	$578	1	2009	$280,398,034	$692
Project 16	320	$195,100,000	$610	1	2009	$233,684,991	$730
Project 17	500	$304,900,000	$610	1	2009	$365,200,173	$730
Project 18	350	$228,900,000	$654	1	2010	$258,163,492	$738
Merrimack Station	**458**	**$354,931,538**	**$775**	**2**	2012	$354,931,538	$775

Table 3. Adjusted Projected Completion Costs by $/kW

1. Project cost in 2012 dollars (Merrimack Station in service year) assuming 6.2% escalation in prices per year
2. $/kW in 2012 dollars

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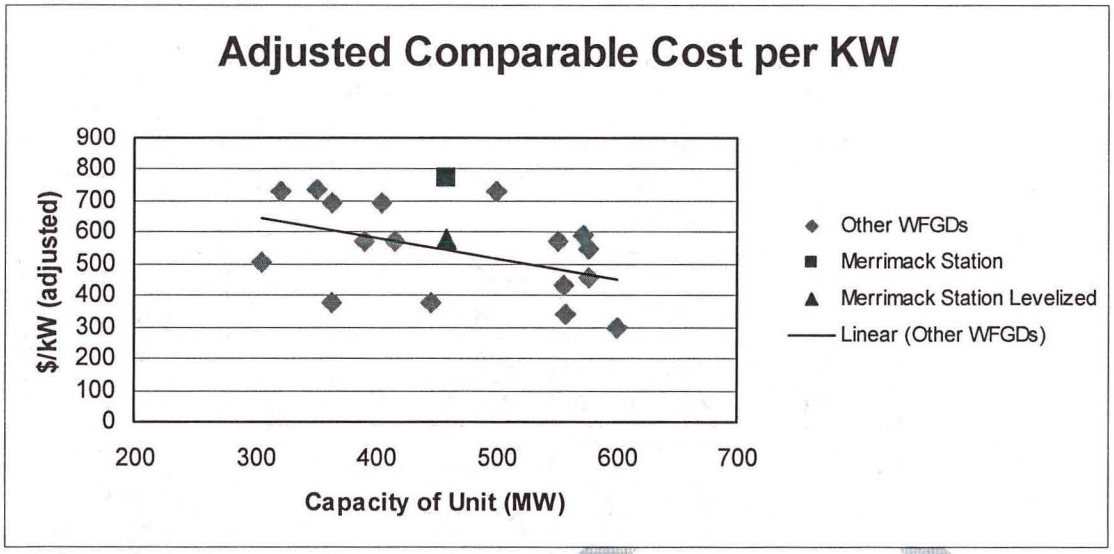

Figure 2. Levelized Cost for Projects of Comparable Size

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Appendix 1.1 - Merrimack Station Design Differences from a Standard WFGD for SO_2 Removal

DESIGN DIFFERENCE	COST IMPACT?	URS ENGINEERING IMPACT %	BOP[1] IMPACT %	FGD IMPACT %	MH IMPACT %	COMMENTS
WFGD scrubber for Hg vs SO_2	Y	0%	5%	10%	0%	Additional absorber engineering and construction needs
Asymmetrical Boilers Feeding Single Absorber	Y	10%	8.5%	5%	0%	More complex duct and flow design/two units into one absorber
Station Site Constraints	Y	5%	5%	0%	10%	Construction over railroad, confined area for MH
All Subcontract Construction Basis	Y	0%	3.9%	0%	0%	Remove 21% markup from applicable estimate items[2]
Foundations	N	0%	0%	0%	0%	Foundations appear to be of relatively typical design
Limited Highway Access	N	0%	0%	0%	0%	Interstate 93 is relatively close via small secondary roads
Pressurized Cyclone Boiler	Y	5%	0%	0%	0%	Increased flow and temperature considerations
Totals=		20%	22.40%	15%	10%	
Cost Adjustment=		$4,256,960.20	$35,664,755.62	$15,008,229.00	$4,482,875.00	
New Totals=		$17,027,840.80	$123,552,903.38	$85,046,631.00	$40,345,875.00	
Equalized $/kW=		**$580.73**				

1= BOP value is made up of direct BOP costs excluding home office engineering.
2= The BOP estimate was analyzed for URS's 21% subcontract markup factor. This markup ($6.3M) was removed from applicable items and the percentage factor calculated based on the actual costs.

For this analysis the following values are assumed:

HO ENG=	$21,284,801	Engineering + eng escalation
BOP=	$159,217,659	BOP + (escalation - eng escalation)
FGD=	$100,054,860	
MH=	$44,828,750	
Total=	$354,931,538	

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request STAFF-02
Dated: 08/30/2012
Q-STAFF-002

Witness: **William H. Smagula**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
With respect to the increase in estimated costs of the scrubber project to $457 million announced in 2008:

a. Please provide copies of all (i) communications, information and data of any kind and in any form presented at any time by any person, including but not limited to employees and outside consultants, to any PSNH or NU-affiliated management person(s) or board of directors/trustees (including but not limited to management and directors' committees and councils), including but not limited to power point presentations, documents, reports, analyses, evaluations and opinions, in any way concerning approving the $457 million estimate, making a decision about whether or not to proceed with the scrubber project, or otherwise reacting to the increase in estimated costs.

b. Please also provide copies of all minutes or other record of decisions by any PSNH or NU-affiliated management person(s) or board of directors/trustees (including but not limited to management and directors' committees and councils) in any way concerning making a decision about whether or not to proceed with the scrubber project or otherwise reacting to the increase in estimated costs.

Response:
On June 25, 2008, NU corporate management at a meeting of the Risk and Capital Committee was provided a detailed project description at an estimated cost of $457M for the purpose of capital project review and approval. The minutes of that meeting are attached. NU corporate management recommended approval of the project by the NU Chairman and CEO. The presentation to the Risk and Capital Committee as well as the presentation provided to the Board of Trustees at the July 14, 2008 meeting are both provided. Although both documents were labeled as confidential documents protected from disclosure by the attorney-client privilege, PSNH waives the privilege in this specific instance to facilitate the review of this project. On July 14, 2008, NU Board of Trustees approved the $457M for Merrimack Clean Air Project Estimate. PSNH Senior Management obtained NU corporate management approval of an advanced in-service date for the project of mid 2012. The recommendation and approval are attached.

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, June 25, 2008)

RECOMMEND APPROVAL OF CAPITAL FUNDING FOR THE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT BY THE CEO OF NU AND THE CHAIRMAN OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Mr. Long directed the Committee's attention to the presentation entitled "Public Service Company of New Hampshire Clean Air Project" (the Clean Air Project) included in the material for the meeting and filed with the records thereof. He then reviewed the New Hampshire Mercury Reduction Act that mandates compliance to mercury emissions standards, and specifies the installation of scrubber technology at Merrimack Units 1 and 2 no later than July 1, 2013. The law stipulates that Public Service Company of New Hampshire (PSNH) must achieve no less than a removal of total mercury resulting in 80% capture of the total amount of mercury contained in the coal burned at all of PSNH's coal-fired units, which includes Schiller Station. Prior RaCC reviews of the Clean Air Project include a conceptual review on April 18, 2007, approval of an initial capital funding request on May 30, 2007, and approval of a revised initial capital funding request of $10 million and up to $35 million of commitment authority on September 24, 2007. An update on the Clean Air Project's schedule, cost, engineering activities, risk assessment and an economic analysis was also provided to the Committee on April 25, 2008.

Mr. Long stated that PSNH management is now seeking approval of funding for the entire Clean Air Project, currently estimated at $457 million, inclusive of funds spent to date. He noted that the cost estimates have been defined by a competitive bidding process, and that prices have escalated from original estimates made in 2006 due to much higher raw material pricing and higher costs of engineering services. The bid proposals indicate that an in-service date of mid-2012 is achievable if two key contracts can be given a limited notice to proceed by June 30. The earlier in-service date reduces the cost of the allowance for funds used during construction, and would allow

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, June 25, 2008)

PSNH to take advantage of incentives built into the New Hampshire legislation for "early reductions" of mercury. Mr. Long stated that despite the capital cost increases, the Clean Air Project remains economic for customers. The continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the region, while providing PSNH customers with low cost energy. Messrs. Long and Vancho then reviewed the components of the $457 million cost estimate, including contingencies of $53 million, the cash flow and earnings projection, financial sensitivities, financial scenarios and key financial takeaways. During the review of the presentation, the Committee raised questions and discussed risks and other matters of concern. It was indicated that according to the Capital Approval Policy, since this project was greater than $50 million it would require Board of Trustees review at the July Board meeting. Messrs. Robb and Shivery left the meeting during this discussion.

After discussion, and upon motion made and seconded, the following preamble and resolutions were unanimously adopted:

WHEREAS, Public Service Company of New Hampshire ("PSNH") management provided the Committee with a capital project approval proposal for the PSNH Clean Air Project and have requested $457 million of capital funding, inclusive of funds spent to date; and

WHEREAS, this Committee has reviewed said proposal;

NOW THEREFORE, BE IT

RESOLVED, that this Committee finds the following capital funding by Public Service Company of New Hampshire ("PSNH") of the PSNH Clean Air Project as described in the material submitted to this meeting and ordered filed with its records thereof acceptable.

Project	Total Cost	Year of Completion
PSNH Clean Air Project	$457 million, inclusive of funds spent to date	2012

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, June 25, 2008)

RESOLVED, that this Committee recommends that the Chairman of the Board, President and Chief Executive Officer of Northeast Utilities and the Chairman of PSNH approve the capital funding by PSNH of the PSNH Clean Air Project, provided however that this Committee further recommends that a status update on the project be submitted to the Committee no less frequently than quarterly and the capital funding by PSNH set forth above shall not be exceeded without prior approval by the Committee.

Mrs. Kuhlman and Messrs. Hitchko, Large, Long and MacDonald left the meeting at this point.

Northeast Utilities System

Clean Air Project
Merrimack Station

Public Service Company of New Hampshire

Clean Air Project

Capital Project Review and Approval

Northeast Utilities

Risk and Capital Committee

Gary Long/John MacDonald/Jim Vancho

June 25, 2008

~~Privileged and Confidential. Prepared at the direction of counsel. Prepared in anticipation of litigation.~~

Data Request STAFF-02
Dated: 08/30/2012
Q-STAFF-002
Page 5 of 50

Executive Summary

Clean Air Project
Merrimack Station

- New Hampshire legislation mandates compliance to mercury emissions standards set forth in the NH Mercury Reduction Act
  - Wet scrubber technology will reduce power plant mercury emissions required by New Hampshire law and is the technology specified by the law
  - There is no other technology which will guarantee capture of 80% of the mercury input of our coal fleet
- Cost estimates have been defined by a competitive bidding process
  - Prices have escalated from original estimates made in 2006 due to much higher raw material pricing and higher costs of engineering service
- Bid proposals indicate that an in-service date of mid-2012 is achievable if two key contracts can be given a limited notice to proceed by June 30
  - Earlier in-service date reduces cost (AFUDC), risk, and allows PSNH to take advantage of incentives built into the New Hampshire legislation for "early reductions" of mercury
- Despite the capital cost increases, the project remains economic for customers and provides a significant investment opportunity for PSNH
  - The NPV of Revenue Requirements of adding the Scrubber versus replacing Merrimack Station energy and capacity supply with market purchases is a benefit to customers of $132 Million
  - Busbar cost increases to $94.55/MWh in 2013
  - The scrubber avoids about $15 Million in sulfur credit purchases annually, included in the customer benefit above
  - Incremental Net Income estimated at $18.5 M in 2013 – first full year of operation

Data Request STAFF-02
Dated: 08/30/2012
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Background – Merrimack Station Benefits PSNH Customers

- Merrimack Station produces 3 million MWh of low cost power annually, about 35% of PSNH's total energy service requirement. The low cost energy produced at Merrimack Station off-sets the higher cost of market purchases in the overall energy service rate
- Operating Merrimack Station in a cost-effective manner has been one of the major reasons why PSNH's energy service rate is the lowest in the region, as much as 25% lower than the average of energy service supply that we track in NE
- Merrimack Station has control technology to satisfy NOx and particulate emissions requirements. With a scrubber, SO_2 and Mercury emissions will be controlled and Merrimack will be among the cleanest coal burning plants nationally
- Coal is the most abundant domestic fossil fuel resource in the United States supplying more than 50% of the nation's power generation fleet, but only 15% of New England's generation. Maintaining the use of this secure fuel resource is important for the diversity of the region's future energy supply
- Historically, coal has maintained a significant price advantage over oil or natural gas as fuel for the power generation sector. Operated as Regulated Generation, this cost savings flows directly to customers

Continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the ISO-NE region, while providing PSNH's customers with low cost energy.

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Background - NH Clean Power Act

Clean Air Project
Merrimack Station

- The NHCPA, in 2002, was the first four-pollutant bill in the nation (SO_2, NOx, Mercury and CO_2)
- The New Hampshire Mercury Reduction Act, enacted in 2006, was the mercury reduction next-step envisioned by the original NHCPA
- The law was developed in a collaborative effort with PSNH, representatives from the environmental community, and the Executive and Legislative branches of state government
- The New Hampshire Mercury Reduction Act specifies the installation of scrubber technology at Merrimack 1 and 2 no later than July 1, 2013
- The law stipulates that PSNH must capture a minimum of 80% of the total amount of mercury contained in the coal burned at all of PSNH's coal-fired units (Merrimack and Schiller)
- Installation of scrubber technology holds the added benefit of significantly reducing SO_2 emissions from the Merrimack Station boilers (anticipated to be 90% reduction or greater)

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The New Hampshire Mercury Reduction Act Specifics:

Clean Air Project
Merrimack Station

- "It is in the public interest to achieve significant mercury emissions reductions at the coal-burning electric power plants in the state as soon as possible. The requirements of this subdivision will prevent, at a minimum, 80 percent of the aggregate mercury content of the coal burned at these plants from being emitted into the air by no later than the year 2013"
- "The Department of Environmental Services has determined that the best known commercially available technology is a wet flue gas desulphurization system…as it achieves significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter and improved visibility (regional haze)"
- "The owner of the affected coal burning sources shall work to bring about early reductions (of mercury emissions) and shall be provided incentives to do so"
- "The installation of scrubber technology will not only reduce mercury emissions significantly but will do so without jeopardizing electric reliability and with reasonable costs to consumers"
- "The installation of such technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources"
- "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of costs, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components"

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Estimate of Project Costs

Clean Air Project
Merrimack Station

Direct Project Costs

➢ Major Contract Islands: (firm price bids)	
• FGD System	$100M
• Material Handling	$45M
• Waste Water Treatment	$15M
• Chimney	$13M
➢ PSNH Project Costs	$30M
➢ Program Manager Costs (URS Washington Group)	
• Balance of Plant & Interconnection	$93M
• Engineering and Construction Management	$59M
TOTAL DIRECT PROJECT COSTS	**$355M**

➢ PSNH Project Contingency	$10M
➢ Program Manager Contingencies	
• Materials Escalation	$23M
• Contingency	$15M
• Scope Growth	$ 4M
TOTAL PROJECT CONTINGENCIES	**$53M**

➢ Power Advocate's Defined Costs Savings	
• Project cost deduction	($6M)
➢ Anticipated Value Engineering*	
• Scope reduction	($5M)
TOTAL ANTICIPATED COST REDUCTIONS	**($11M)**

➢ NU Corporate Costs	
• AFUDC	$55M
• Indirect Costs	$5M
TOTAL CORPORATE COSTS/AFUDC	**$60M**

Total Project Cost Estimate = $457M

*Note: Alternative material handling proposal in consideration that would reuse existing station equipment and reduce project costs by about $5M

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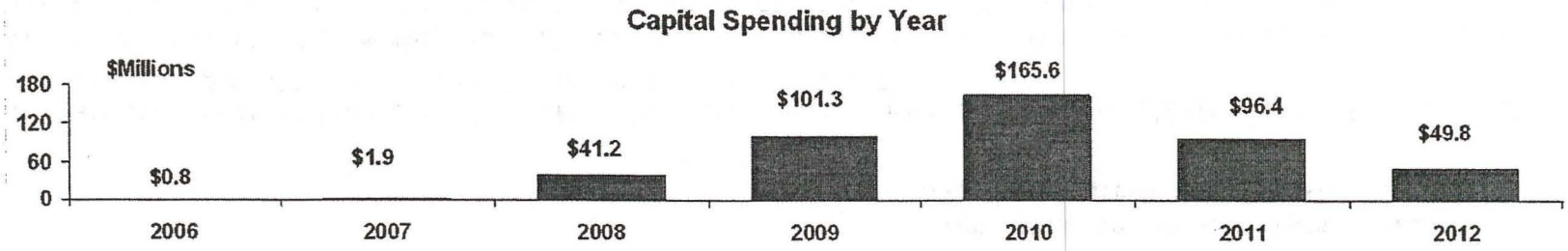
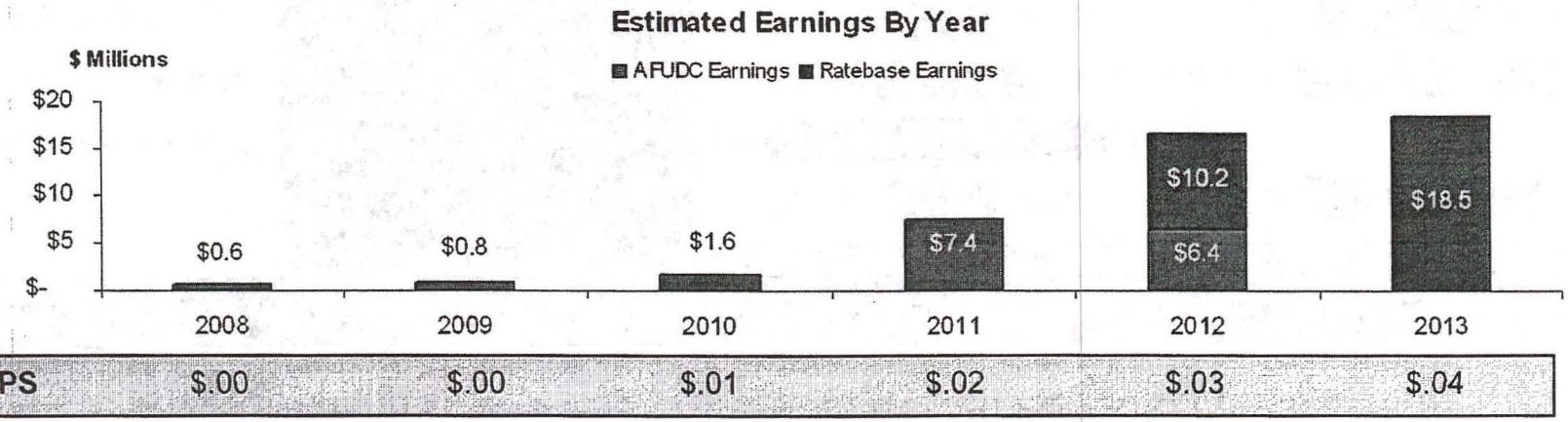
Cashflow and Earnings Projection

Clean Air Project
Merrimack Station





EPS	$.00	$.00	$.01	$.02	$.03	$.04

Assumptions:

- Base-case project costs are estimated at $457M
- Project expected to be in-service on June 30, 2012
- Assumes 9.81% ROE on 47.23% of Capital Structure
- Average Shares outstanding per 2009-2013 Forecast

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Financial Sensitivities

Clean Air Project
Merrimack Station

- Base-case assumptions result in net customer benefit of $132 Million and a 2013 busbar cost of $94.55
- Net customer cost is most sensitive to expected future natural gas and coal prices

Assumption Category	Assumptions			2008 PV of Net Customer Cost[1] 2012-2027 ($Mil)					2013 Plant Busbar Cost ($/MWh)						
	Downside	Base	Upside	($225)	($175)	($132)	($100)	$0	$91	$92	$93	$94.55	$96	$97	$98
Capital Cost	+10%	$457.5 mil	-10%	($159)	$(27)	$27	($105)		$92.31	$(2.24)	$2.24		$96.79		
2012 Gas Prices, MMBTU[3]	-5%	$11.00	+5%	($213)	$(81)	$81	($51)								
2012 Coal Prices, MMBTU[3]	+5%	$4.82	-5%	($180)	$(48)	$48	($84)		$92.02	$(2.53)	$2.53		$97.08		
2012 RGGI/Federal Carbon Costs per Ton[2,3]	+50%	$7/$21	-50%	($158)	$(26)	$26	($106)		$92.53	$(2.02)	$2.02		$96.57		

White text in bars represents change in values;
Black text beside bars represents sensitivity result.

Notes:

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Amounts presented reflect RGGI/federal (Lieberman-Warner) cost estimates. Impacts are equivalent at given prices since RGGI does not provide for carbon allowances but federal proposals are assumed to include Merrimack allocations starting at 67% (per Lieberman-Warner).
3. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.

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Financial Scenarios

Clean Air Project
Merrimack Station

	Unlikely Low	Possible Low	Base	Possible High	Unlikely High
NPV - Net Customer Cost[1]	$210 Mil	$43.4 Mil	($132 Mil)	($296 Mil)	($461 Mil)
Monthly Residential Customer Cost Impact[4]	$1.61	$0.33	($1.01)	($2.28)	($3.54)
2013 Plant Busbar Cost ($/MWH)	$104.44	$100.77	$94.55	$89.52	$84.49
Net Inc - 2013 (First Full Year In-Service)	$21.5 Mil	$20.1 Mil	$18.5 Mil	$18.1 Mil	$17.7 Mil
Assumed Probability	5%	25%	-	25%	5%
Parameters					
Capital Costs, Millions	$532	$497	$457	$447	$437
2012 Gas Prices, MMBTU[2]	$9.90	$10.45	$11.00	$11.55	$12.10
2012 Coal Prices, MMBTU[3]	$5.30	$5.06	$4.82	$4.58	$4.34
2012 Carbon Costs, Ton (RGGI/Federal)[2,3]	$15/$45	$10/$30	$7/$21	$3.5/$10.6	$0/$0

Case Legend

- **Unlikely Low** — Case reflects project in-service delayed one year and cost overun ($45M), cooling tower addition ($30M), minimal Gas/coal Spread
- **Possible Low** — Case reflects project in-service on-time with cost overun ($10M), cooling tower addition ($30M), decreased Gas/coal Spread
- **Base** — Current assumptions
- **Possible High** — Case reflects project in-service 6 months early ($10M), project costs as expected, benign carbon legislation, increased gas/coal spread
- **Unlikely High** — Case reflects project in-service 6 months early ($10M) with lower than expected costs ($10M), no carbon legislation, maximum gas/coal spread

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Amounts presented reflect RGGI/federal (Lieberman-Warner) cost estimates. Impacts are equivalent at given prices since RGGI does not provide for carbon allowances but federal proposals are assumed to include Merrimack allocations starting at 67% (per Lieberman-Warner).
3. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.
4. Based on NPV Net Customer Cost levelized over the period 2012-2027, and average residential usage of 500 kWh per month.

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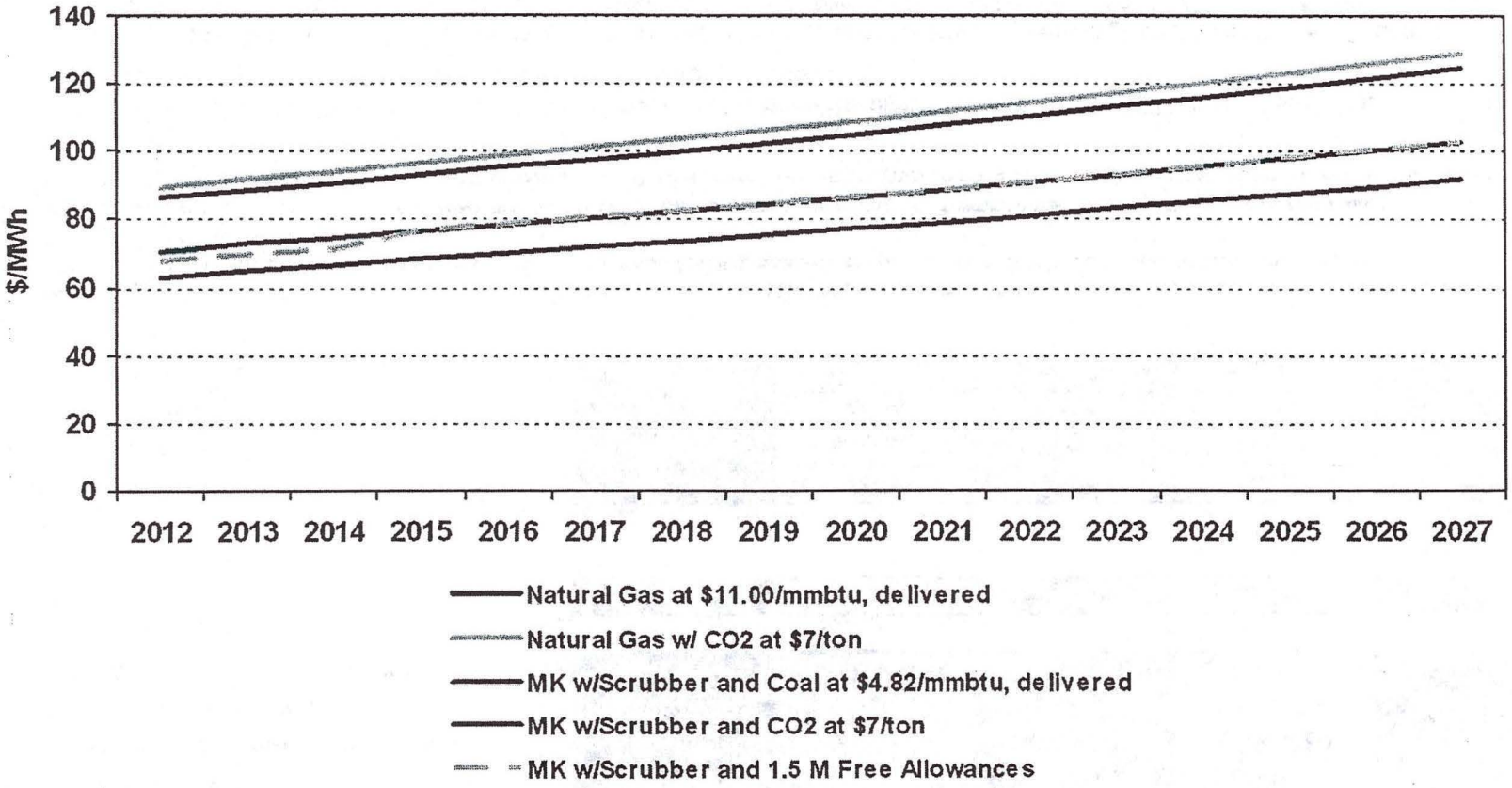
Economic Analysis Supports That Merrimack Station With Scrubber Will Be Dispatched

Clean Air Project
Merrimack Station



- Natural Gas plant heat rate of 7,620 Btu/kWh in a Combined Cycle unit
- SO_2 at $500/ton, NOx at $1,300/ton

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Key Financial Takeaways

Clean Air Project
Merrimack Station

- Customer value of scrubber installation extremely sensitive to future expected natural gas/coal price spread
  - At assumed 2012 price levels and other base case parameters, a spread of approximately $5.29/mmbtu (escalating) is required to create customer benefits
- Impact of RGGI/Federal carbon legislation is not expected to render scrubber investment uneconomic to customers at current projected costs
  - Assumes any Federally imposed carbon legislation would grant carbon allowances to generators (approximately 67% of Merrimack's requirement)
  - Absent Federal allocations (or under RGGI), assuming all other base case assumptions, a 2012 carbon cost of $30/ton (escalating) or greater would eliminate customer value of scrubber installation
- Assuming base case fuel and carbon assumptions, capital cost estimates have meaningful headroom before rendering investment uneconomic
  - However, reductions in natural/gas coal spread and increases in carbon costs would put pressure on ability to construct within the current projection

Investment is essentially a long spread position on natural gas/coal with carbon and construction risk

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Project Benefits are Accentuated by Advancing the In-Service Date to mid-2012

Clean Air Project
Merrimack Station

- Financial
  - Reduces AFUDC cost by $10 Million
  - Limits exposure to material or labor cost escalation for project elements not covered by firm price contracts
  - Generates real earnings one year sooner
- Environmental
  - Eliminates an additional 31,350 tons of SO_2
  - Eliminates an additional 229 pounds of Mercury
  - Reduces particulate emissions to less than 1% one year sooner
- Customer
  - Produces "early reduction mercury credits" that can be used for
    - Compliance in future years if operational issues with the scrubber arise
    - Conversion to fungible SO_2 allowances (estimated at 12,500 allowances)

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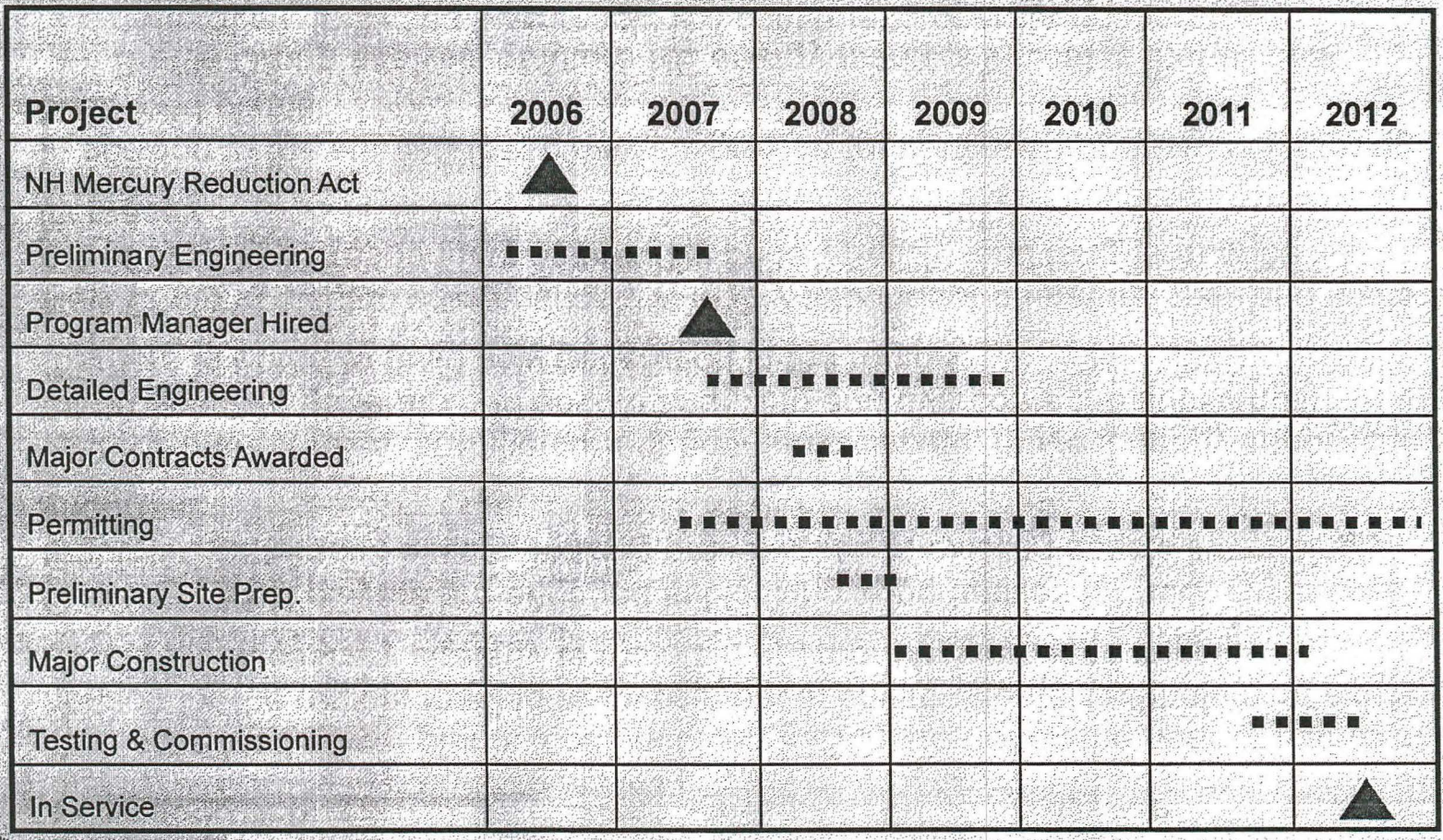
Revised Project Schedule

Clean Air Project
Merrimack Station



Northeast Utilities System

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Regional Barriers to Adding New Base Load Generation in New England Cause Merrimack to be Strategically Positioned for Re-Investment

Clean Air Project
Merrimack Station

- New base load power plants (coal, nuclear, IGCC) are not on the near or mid-term horizon for the region, making re-investment in environmental technology at existing assets the necessary strategy to maintain appropriate base-load supply
- Current market players are engaged in blocking opportunities for new, lower cost, regulated generation assets, making preservation of existing assets increasingly important
- ISO-NE market rules, and the current economic climate, make it nearly impossible for prospective generators to secure financing and overcome the substantial "barriers to entry" to build new generation in the region
- New England electric energy supply is highly dependent on natural gas, and costs are subject to corresponding commodity price volatility, and long-term price increases
- In addition to the support these barriers provide for continued operation of existing base-load plants:
  - Brattle Group analysis of future NE energy markets indicates that all coal generation, including Merrimack, will continue to operate economically
  - Operation of Merrimack Station on coal provides stability to the power supply in the region
  - Loss of PSNH's Merrimack Station would call into question the viability of operating the remaining generating assets as a fleet

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Conclusion

Clean Air Project
Merrimack Station

- Installation of the scrubber is required by NH law to meet mercury emissions requirements
- Merrimack Clean Air Project capital costs have increased significantly since the original project costs estimates were prepared in 2006, and stand at $457M
- Under the base case and with varying assumptions, continued operation of Merrimack Station with the Clean Air Project remains economically beneficial for customers
- State law allows for recovery of prudently incurred costs to construct and operate the scrubber
- The project team is in place and prepared to execute contracts now and begin construction in earnest late this year, with a project in-service date of mid-2012
- The proposal to construct and operate a scrubber at Merrimack Station, in conformance with the NH Mercury Reduction Law, is in the best interest of PSNH's customers and shareholders

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Appendix Materials

PSNH Clean Air Project

June 25, 2008

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Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Remaining bids received from vendors are significantly higher than expected related to material and handling costs. Note: The bids on the major equipment have been received.	2008	$10 million	20%	$2 million	Currently carrying out the procurement schedule. The Purchasing area is trying to stimulate competition during the bid process. Lastly as the required implementation date allows for some slippage in the schedule.
Lack of sufficient, qualified construction labor results in increased costs to import labor resources, schedule delays to wait for resources to become available.	2009-12	$50 million	10%	$5 million	WGI will initiate the National Maintenance Agreement. Meetings have been held with the union trades to discuss the project and labor requirements up front.
Inability to lock in firm prices during contracting phase exposes the project to price volatility and currency risk.	2008-9	$25 million	20%	$5 million	The RFP is being structured for fixed/lump sum pricing. The contract will be negotiated to try and include these parameters.

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Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Vendors unable to meet project design criteria resulting in non-conforming bids. Note: bids received with mercury criteria. Risk relates to remaining design specifications.	2008-9	$25 million	25%	$6.25 million	In the event this occurs, an acceptable outcome will be negotiated during the procurement process.
Inability to design appropriate plant integration plans resulting in MK1 bypass, boiler implosion and noise issues.	2008-9	$12.5 million	50%	$6.25 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.
Scope definition changes drastically during construction resulting in additional expenditures and/or potential schedule delays.	2008-12	$18.75 million	20%	$3.75 million	PSNH team will work closely with WGI & EPC contractors to minimize the impact.
Proposed design is inadequate and does not meet operability/reliability/ constructability requirements resulting in complete redesign.	2008-9	$12.5 million	30%	$3.75 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.

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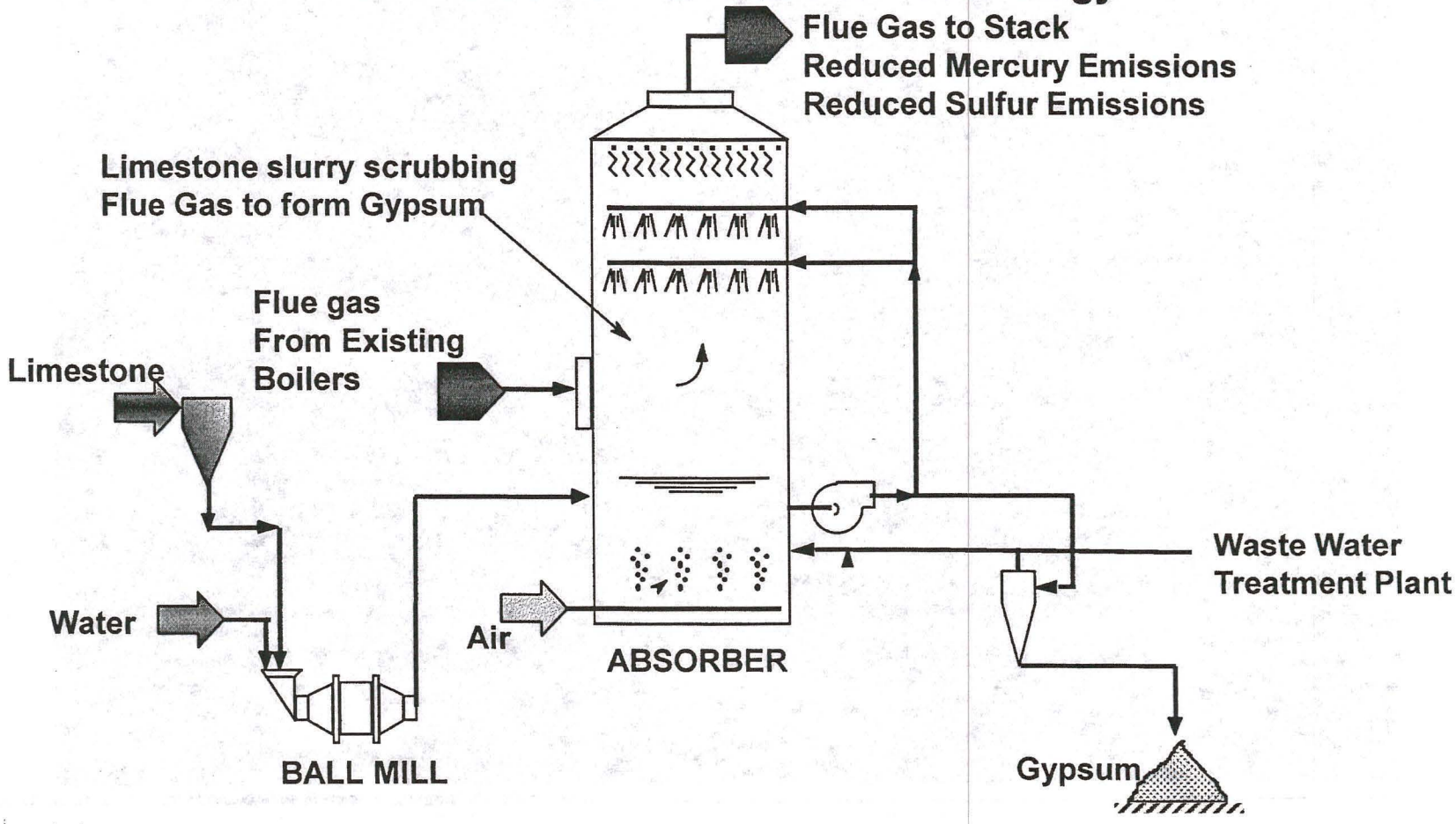
Scrubber Schematic

Clean Air Project
Merrimack Station

Wet Flue Gas Desulfurization Technology



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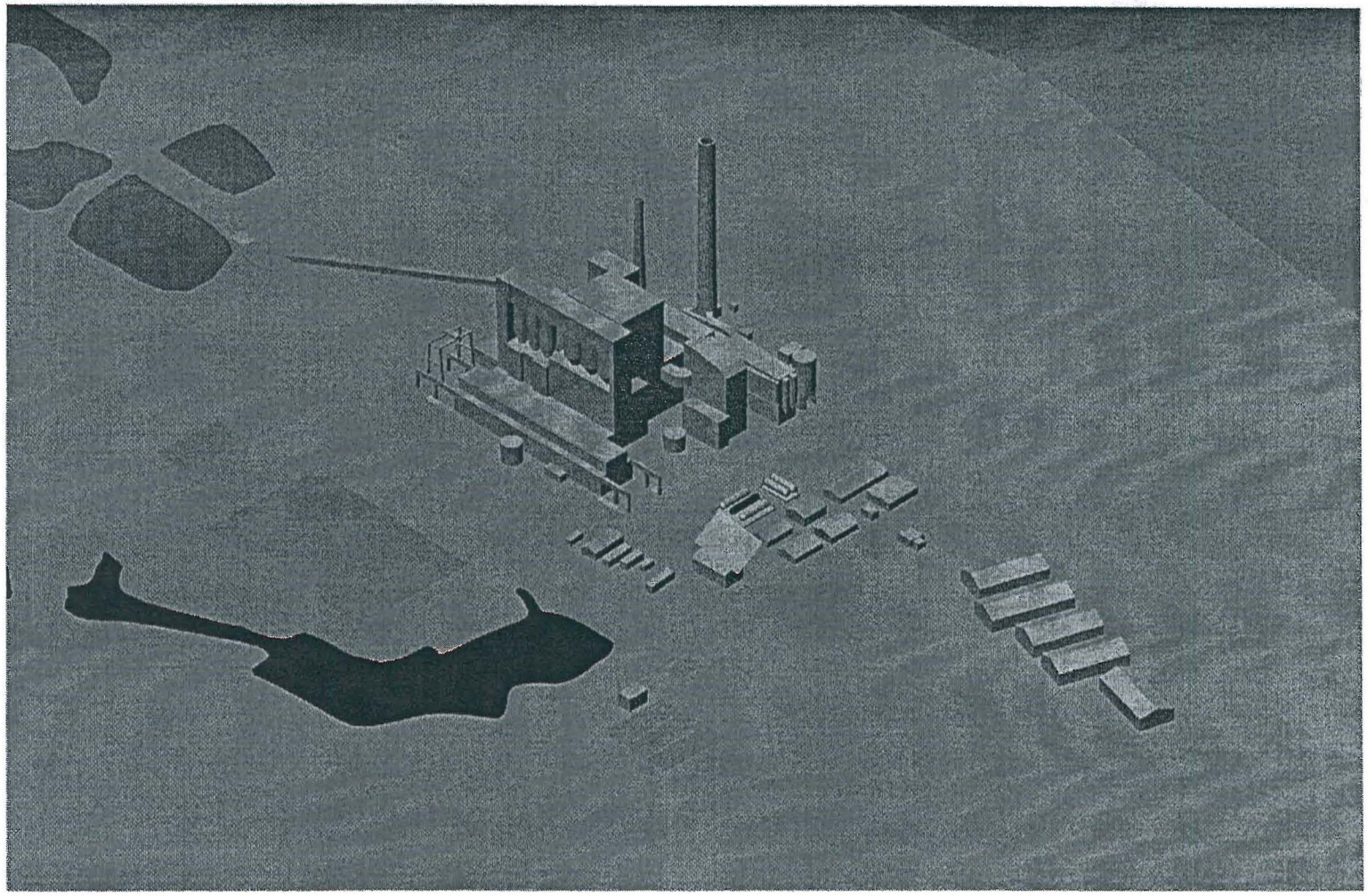
Merrimack Station: 2008

Clean Air Project
Merrimack Station



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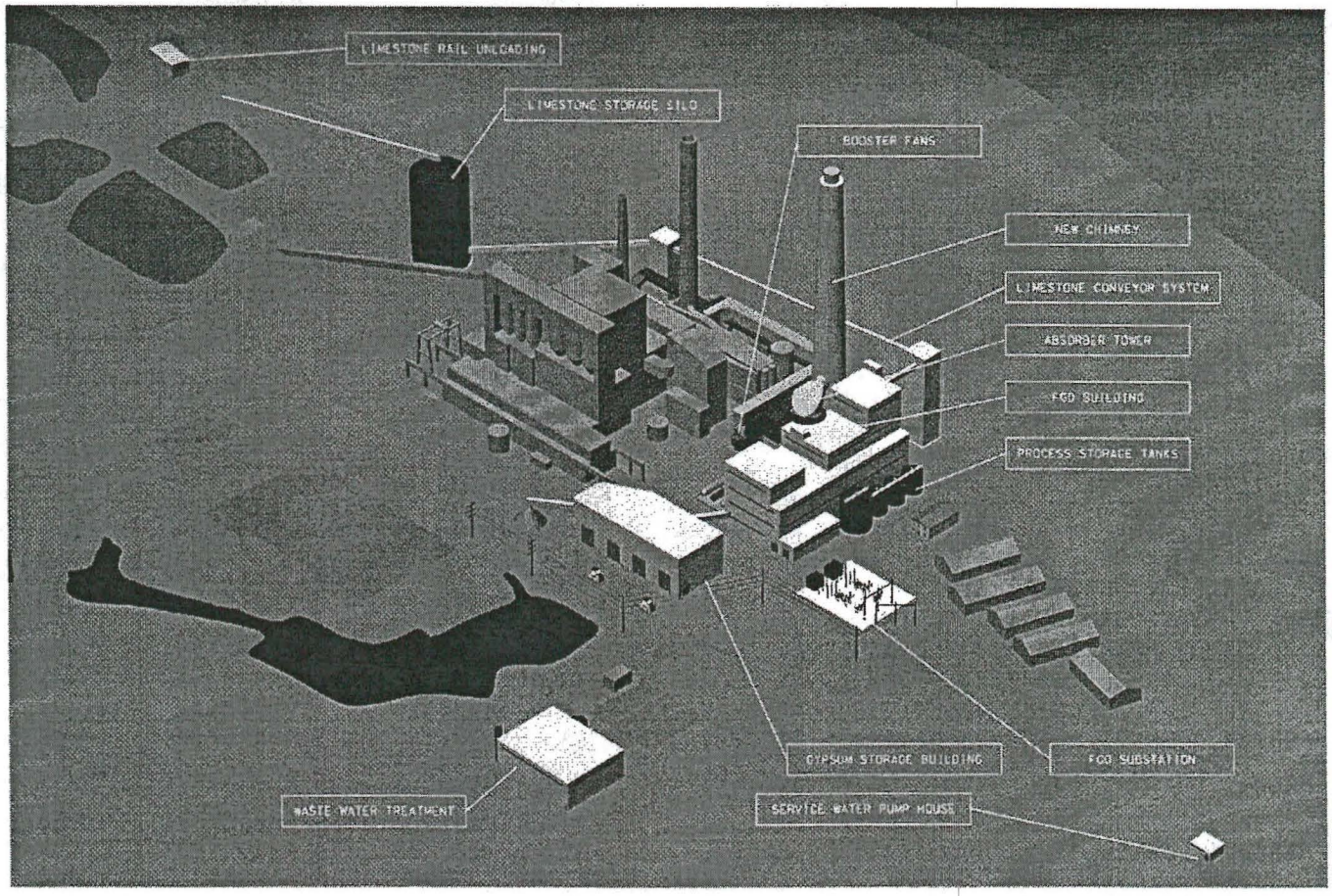
Merrimack Station: 2013

Clean Air Project
Merrimack Station



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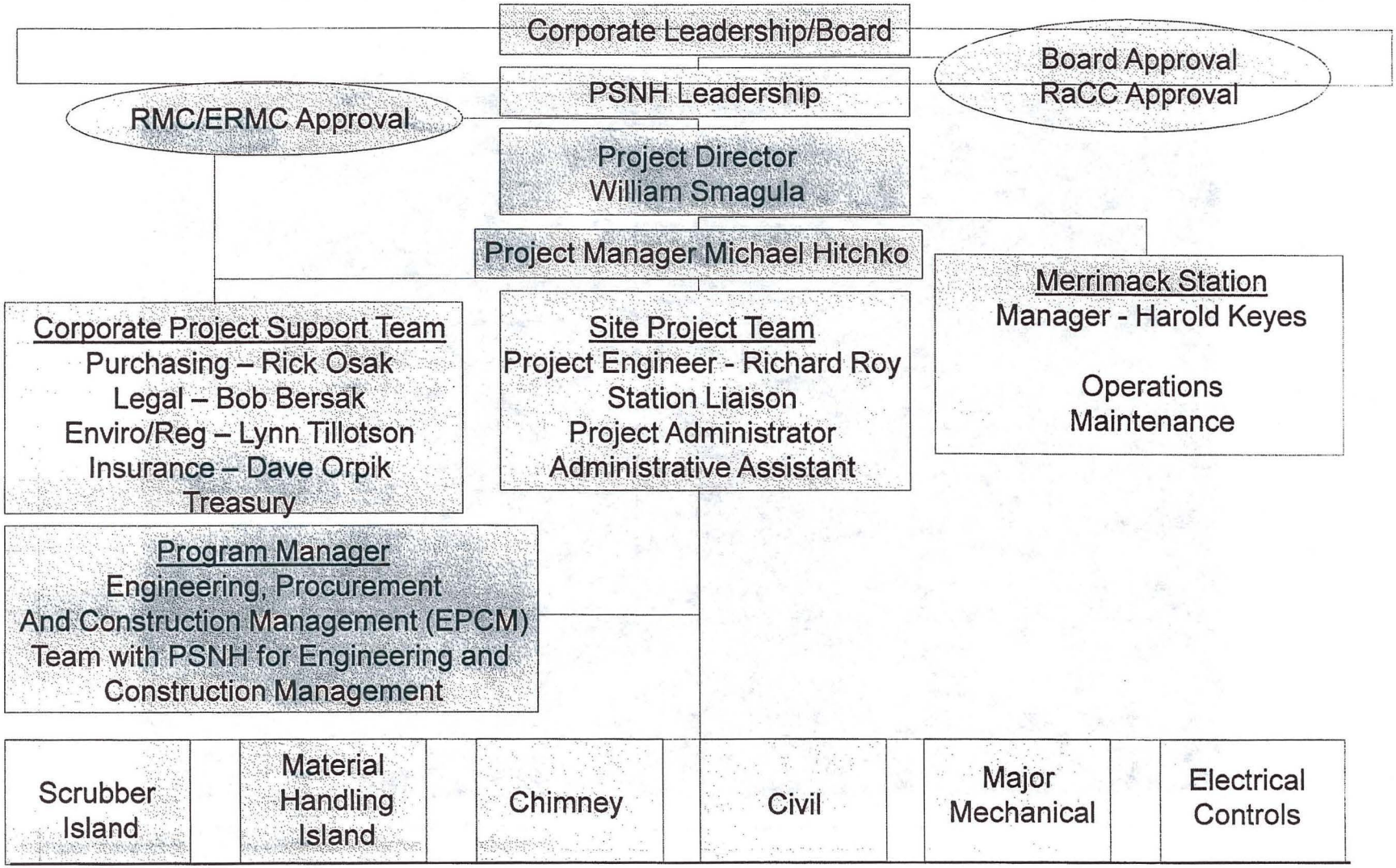
Project Organization

Clean Air Project
Merrimack Station



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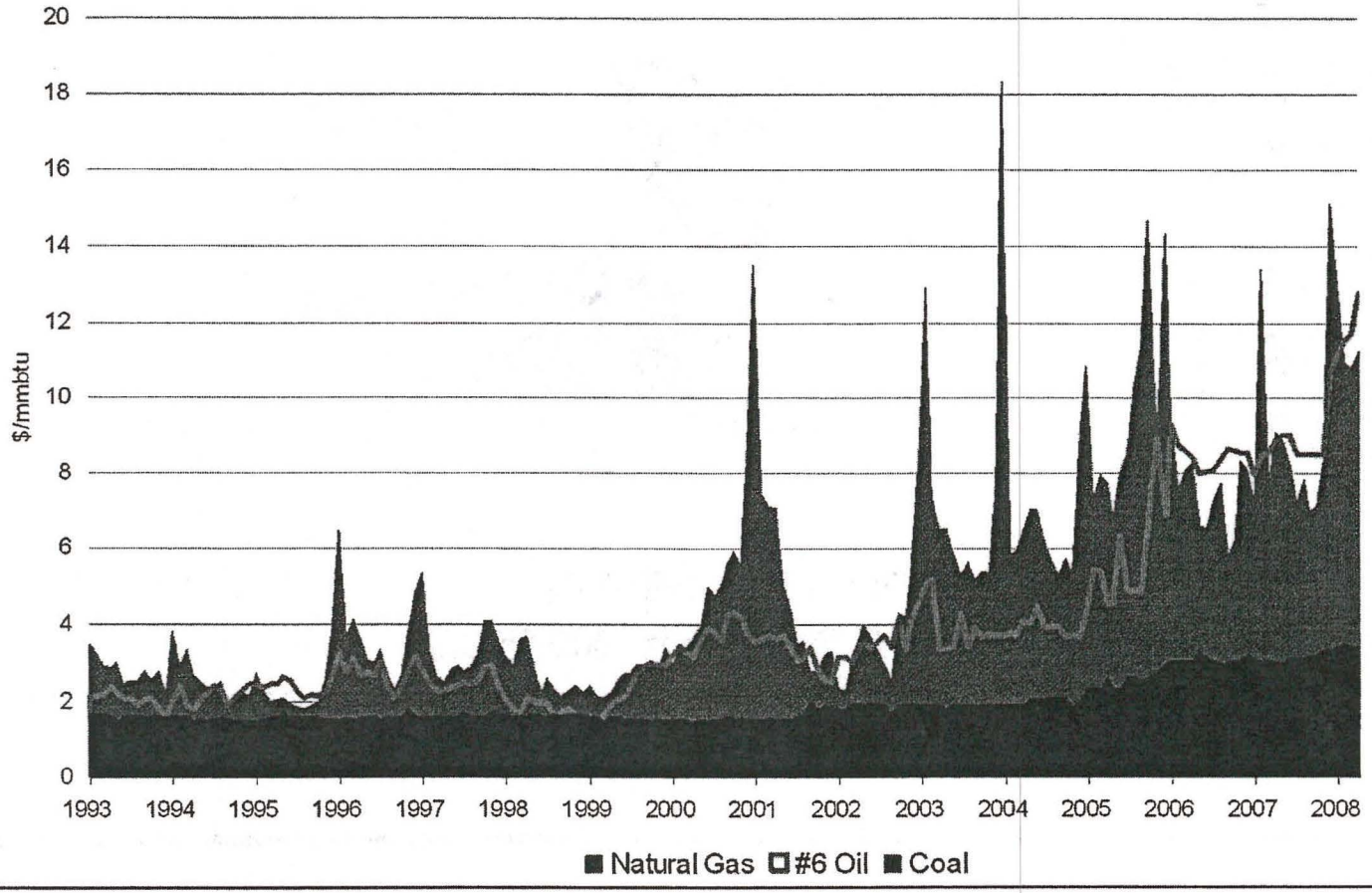
Historic Price Volatility Suggests Coal Will Find a Way to be Cheaper than Alternatives

Clean Air Project
Merrimack Station

PSNH Actual/Quoted Delivered Fuel Costs



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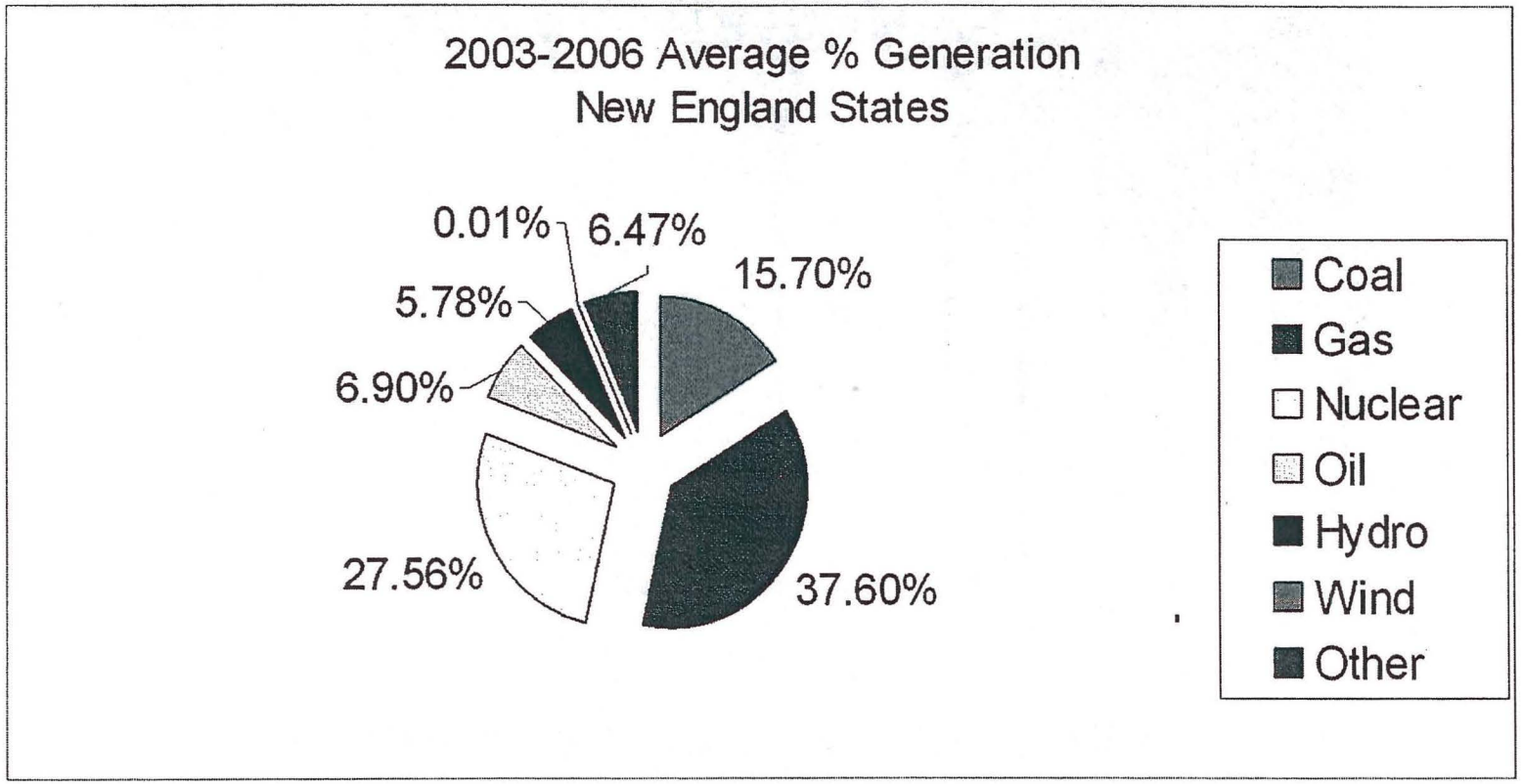
ISO-NE Energy Supply by Fuel Type

Clean Air Project
Merrimack Station



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Northeast Utilities System

Clean Air Project
Merrimack Station

Public Service Company of New Hampshire

Clean Air Project

Capital Project Review and Approval

Northeast Utilities

Board of Trustees

Gary Long/Cameron Bready

July 15, 2008

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Executive Summary

Clean Air Project
Merrimack Station

- New Hampshire legislation mandates compliance to mercury emissions standards set forth in the NH Mercury Reduction Act
  - Wet scrubber technology will reduce power plant mercury emissions required by New Hampshire law and is the technology specified by the law
  - There is no other technology which will guarantee capture of 80% of the mercury input of our coal fleet
- Cost estimates have been defined by a competitive bidding process
  - Prices have escalated from original estimates made in 2006 due to much higher raw material pricing and higher costs of engineering service
- Bid proposals indicate that an in-service date of mid-2012 is achievable
  - Earlier in-service date reduces cost (AFUDC), risk, and allows PSNH to take advantage of incentives built into the New Hampshire legislation for "early reductions" of mercury
- Despite the capital cost increases, Merrimack Station remains economic for customers under expected conditions and provides a significant investment opportunity for PSNH
  - The NPV of Revenue Requirements of adding the Scrubber versus replacing Merrimack Station energy and capacity supply with market purchases is a benefit to customers of $132 Million
  - The scrubber avoids about $15 Million in sulfur credit purchases annually, included in the customer benefit above
  - Incremental Net Income estimated at $18.5 M in 2013 – first full year of operation

Background – Merrimack Station Benefits PSNH's Customers

Clean Air Project
Merrimack Station

- Merrimack Station produces 3 million MWh of low cost power annually, about 35% of PSNH's total energy service requirement. The low cost energy produced at Merrimack Station off-sets the higher cost of market purchases in the overall energy service rate
- Operating Merrimack Station in a cost-effective manner has been one of the major reasons why PSNH's energy service rate is the lowest in the region, as much as 25% lower than the average of energy service supply that we track in NE
- Merrimack Station has control technology to satisfy NOx and particulate emissions requirements. With a scrubber, SO_2 and Mercury emissions will be controlled and Merrimack will be among the cleanest coal burning plants nationally
- Coal is the most abundant domestic fossil fuel resource in the United States supplying more than 50% of the nation's power generation fleet, but only 15% of New England's generation. Maintaining the use of this secure fuel resource is important for the diversity of the region's future energy supply
- Historically, coal has maintained a price advantage over oil or natural gas as fuel for the power generation sector. Operated as Regulated Generation, this cost savings flows directly to customers

Continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the ISO-NE region, while providing PSNH's customers with low cost energy.

Financial Assessment – Summary Metrics

Total Installed Capital Costs	$457M
Capital Cost $ / kW	$1,000[1]
NPV of Base Case Customer Benefit	$132M
2013 Net Income Contribution	$18.5M
2013 EPS Contribution (Diluted)	$.04/share
Busbar Cost (2013)	$94.55/MWh

Key assumptions :

- Project in-service on June 30, 2012
- 9.81% ROE on 47.23% equity component of capital structure
- Base case natural gas price of $11/mmbtu, coal of $4.82/mmbtu and carbon of $7/ton

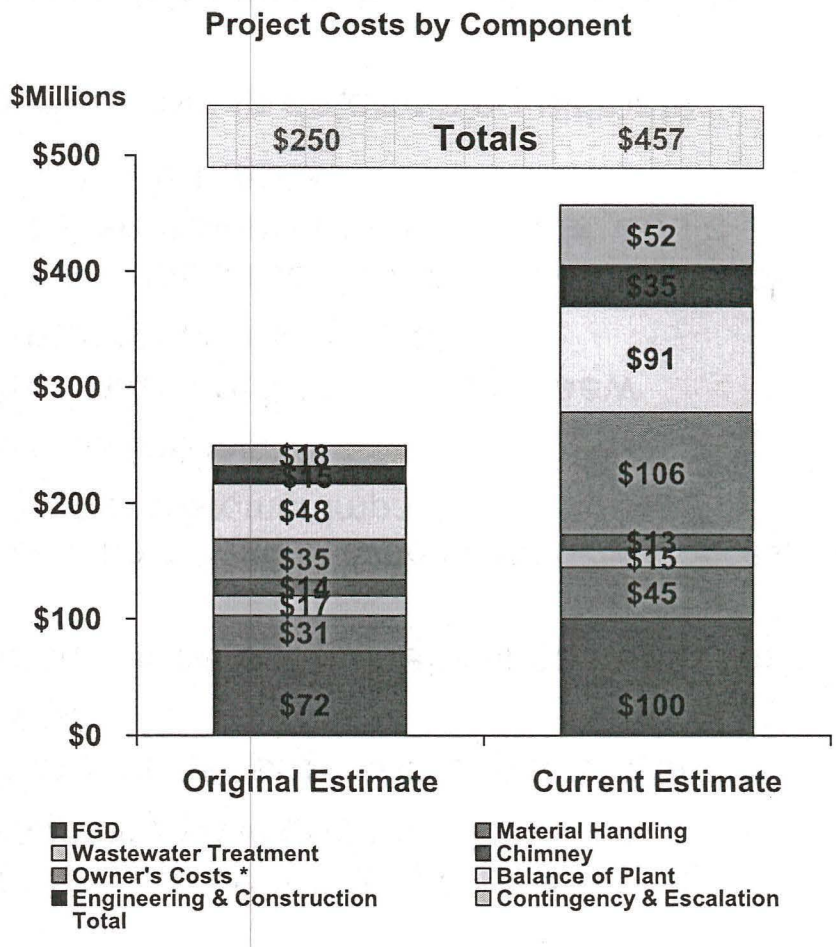
Note:

1. For reference, capital costs for a new CCGT would be approximately $1,600 - $1,700/kw. A new peaker would be approximately $950 – 1,000/kw.

Estimate of Project Costs

Clean Air Project
Merrimack Station

Major Island Contracts (Firm-Price Bids)	
FGD System	$100M
Material Handling	$45M
Waste-water Treatment	$15M
Chimney	$13M
PSNH Project Costs	$44M
Other Program Manager Costs	
Balance of Plant and Interconnection	$91M
Engineering and Construction	$35M
Contingency and Escalation	$52M
AFUDC	$57M
Total Direct Costs	**$452M**
NU Indirect Costs	**$5M**
Project Total	**$457M**



* Includes PSNH Project Costs, Indirect Costs, and AFUDC

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Financial Assessment - Overview

Clean Air Project
Merrimack Station

- Customer benefit/cost of scrubber installation is dependent upon customer alternatives for securing the energy and capacity provided by Merrimack
  - Analysis assumes that customers will procure energy and capacity from the market if Merrimack is not operational
  - Market price for energy will likely continue to be set by natural gas units for the foreseeable future
    - → Expected future price for natural gas and the spread between natural gas prices and coal prices are critical to assessment of customer impacts
- Financial customer benefit/cost determined as follows:
  - PV of net revenue requirements of Merrimack facility (including new scrubber) – PV of market energy and market capacity costs
  - Customer benefit is achieved when the revenue requirements of Merrimack are lower than the costs of procuring the energy and capacity that would otherwise be provided by Merrimack from the market
- Future impact of carbon may play an important role in determining ultimate customer benefit/cost
  - Carbon costs are expected to impact electricity rates, but coal plants will likely be disproportionally affected given their emission rates versus natural gas plants

Financial Sensitivities

Clean Air Project
Merrimack Station

- Base-case assumptions result in net customer benefit of $132 million
- Net customer benefit is most sensitive to expected future natural gas and coal prices and the relative spread between the two commodities

Assumption Category	Assumptions			2008 PV of Net Customer Cost[1] 2012-2027 ($Mil)	Net Customer Impact Break-Even Rates
	Downside	Base	Upside	($300) ($180) ($132) ($50) $40	
Capital Cost	+10%	$457 mil	-10%	$(159) $(27) $(27) $(105)	$684 mil
2012 gas Prices, MMBTU[2]	-10%	$11.00	+10%	$(295) $(163) $163 $31	$10.10
2012 coal prices, MMBTU[2]	+10%	$4.82	-10%	$(228) $(96) $96 $(36)	$5.49
Implied Gas/coal Spread	$4.60	$6.18	$7.76	N/A[4]	$5.29[4]
2012 Carbon Costs[2,3]	+50%	$7	-50%	$(167) $(35) $35 $(97)	$30.13

Text in bars represents change in values;
text beside bars represents sensitivity result.

Notes:

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.
3. Reflects net impact on a $/ton basis for either RGGI or Federal policies excluding any allocations of allowances.
4. Spread not sensitized as impact depends on underlying natural gas and coal prices. Break even is based on a $4.82/mmbtu Coal Price (~$130 per delivered ton).

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Financial Scenarios

Clean Air Project
Merrimack Station

- The following scenarios, denoted by their assumed probability of occurrence, demonstrate the compounding impacts of a variety of assumption changes on the key financial metrics for the project:

	Unlikely Low	Possible Low	Base	Possible High	Unlikely High
NPV - Net Customer Cost	**$481 MIL**	**$194 MIL**	**($132 MIL)**	**($413 mil)**	**($719 mil)**
Monthly Residential Customer Cost Impact	**$3.70**	**$1.49**	**($1.01)**	**($3.17)**	**($5.52)**
2013 Plant Busbar Cost ($/MwH)	**$102.41**	**$100.37**	**$94.55**	**$87.86**	**$79.44**
Net Income - 2013 (First full Year In-Service)	**$21.5 mil**	**$20.1 MIL**	**$18.5 MIL**	**$18.1 mil**	**$17.7 mil**
Assumed probability	*5%*	*25%*	-	*25%*	*5%*
Parameters					
Capital Costs, Millions	$532	$497	$457	$447	$437
2012 Gas Prices, MMBTU	$8.80	$9.90	$11.00	$12.10	$13.20
2012 Coal Prices, MMBTU	$5.78	$5.30	$4.82	$4.34	$3.86
2012 Carbon Costs, Ton	$30	$20	$7	$5	$0

Case Legend

Unlikely Low	Case reflects project in-service delayed one year and cost overun ($45M), cooling tower addition ($30M), minimal Gas/coal Spread
Possible Low	Case reflects project in-service on-time with cost overun ($10M), cooling tower addition ($30M), decreased Gas/coal Spread
Base	Current assumptions
Possible High	Case reflects project in-service 6 months early ($10M), project costs as expected, benign carbon legislation, increased gas/coal spread
Unlikely High	Case reflects project in-service 6 months early ($10M) with lower than expected costs ($10M), no carbon legislation, maximum gas/coal spread

- Other scenarios considered:

	Customer Cost/(Benefit)
• $200 Oil Scenario:	($437 million)
• $50 Carbon Cost:	$70 million

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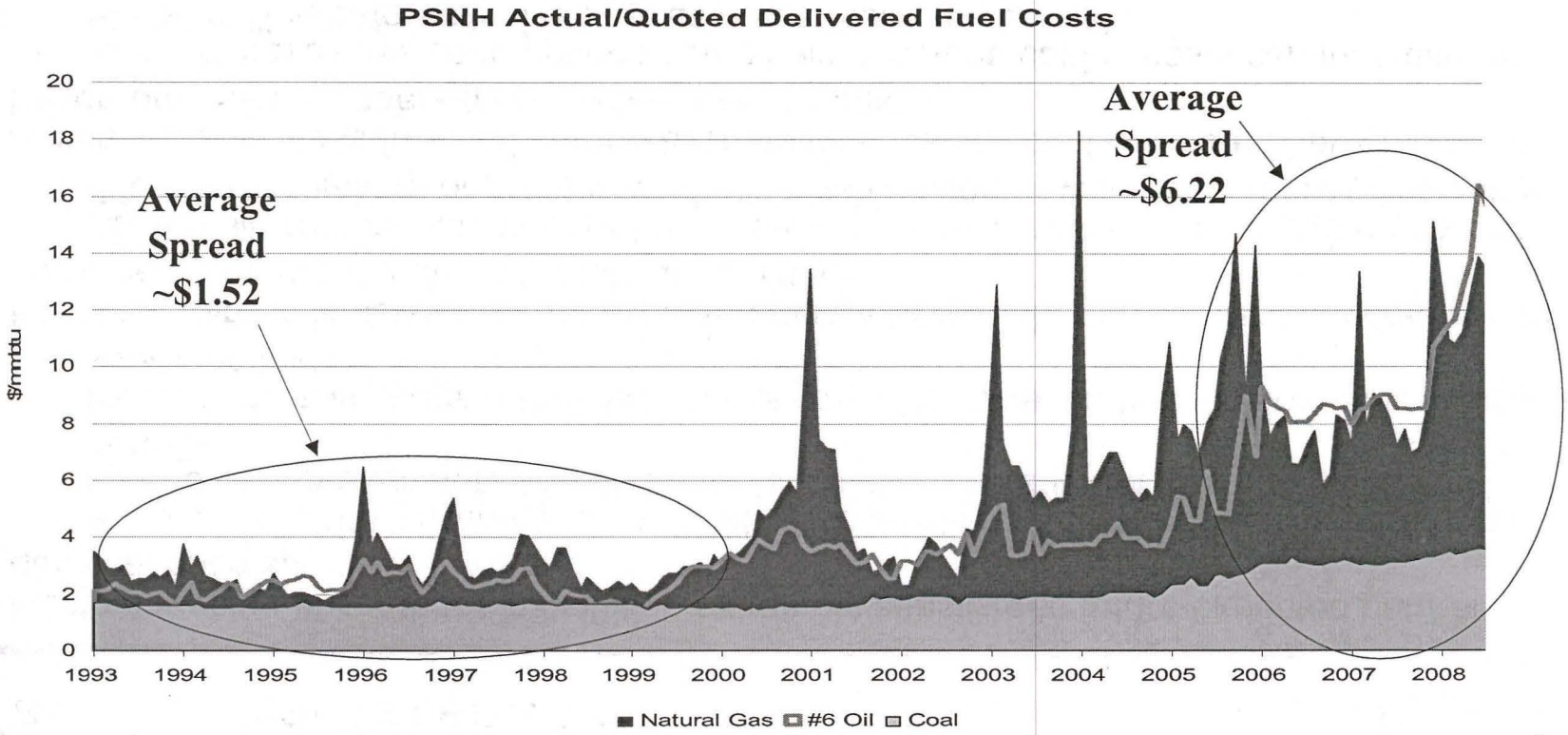
Historic Fuel Spreads

Clean Air Project
Merrimack Station

- Gas/Coal spread has averaged $3.18/mmbtu over the last 15 years, as compared to the required customer break-even level of $5.29/mmbtu (based on current price levels)
  - However, post the hurricane season of 2005, the spread has averaged $6.22/mmbtu
- Since January 2007, the spread has averaged nearly $6.63/mmbtu and current spreads are more than ~$9/mmbtu



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Key Financial Takeaways

Clean Air Project
Merrimack Station

- Customer value of scrubber installation extremely sensitive to future expected natural gas/coal price spread
  - At assumed 2012 natural gas and coal price levels and other base case parameters, a spread of approximately $5.29/mmbtu (escalating) is required to create customer benefits
  - Recent spreads suggest that this level is realistic; however, historic spread levels have averaged lower
- Impact of carbon legislation is not expected to render scrubber investment uneconomic to customers at current projected costs under RGGI
  - Absent allocations, assuming all other base case assumptions, a net carbon cost of $30/ton (escalating) or greater would diminish customer value of scrubber installation
- Assuming base case fuel and carbon assumptions, capital cost estimates have meaningful headroom before rendering investment uneconomic
  - All other base case assumptions being held constant, capital costs can increase to ~$684 million before eliminating customer economic benefits
  - However, reductions in natural/gas coal spread and increases in carbon costs would put pressure on base case capital cost estimates
- Generation ratemaking making structure allows for PSNH to earn 9.81% ROE on equity invested in the project under all scenarios presented
  - Assumes that project capital costs are deemed prudent

Investment is essentially a long spread position on natural gas/coal with carbon and construction risk

Revised Project Schedule

Clean Air Project
Merrimack Station

Project	2006	2007	2008	2009	2010	2011	2012
NH Mercury Reduction Act	▲						
Preliminary Engineering	▪▪▪▪▪▪▪▪						
Program Manager Hired		▲					
Detailed Engineering		▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪			
Major Contracts Awarded			▪▪▪				
Permitting		▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪
Preliminary Site Prep.			▪▪▪				
Major Construction				▪▪▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	
Testing & Commissioning						▪▪	▪▪▪▪
In Service							▲

Northeast Utilities System

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Conclusion

Clean Air Project
Merrimack Station

- Installation of the scrubber is required by NH law to meet mercury emissions requirements
- Merrimack Clean Air Project capital costs have increased significantly since the original project costs estimates were prepared in 2006, and stand at $457M
- Under the base case, continued operation of Merrimack Station with the Clean Air Project remains economically beneficial for customers
- State law allows for recovery of prudently incurred costs to construct and operate the scrubber
- The project team is in place and prepared to execute contracts now and begin construction in earnest late this year, with a project in-service date of mid-2012
- The proposal to construct and operate a scrubber at Merrimack Station, in conformance with the NH Mercury Reduction Law, is in the best interest of PSNH's customers and shareholders

Northeast Utilities System

Clean Air Project
Merrimack Station

Appendix Materials

PSNH Clean Air Project

July 15, 2008

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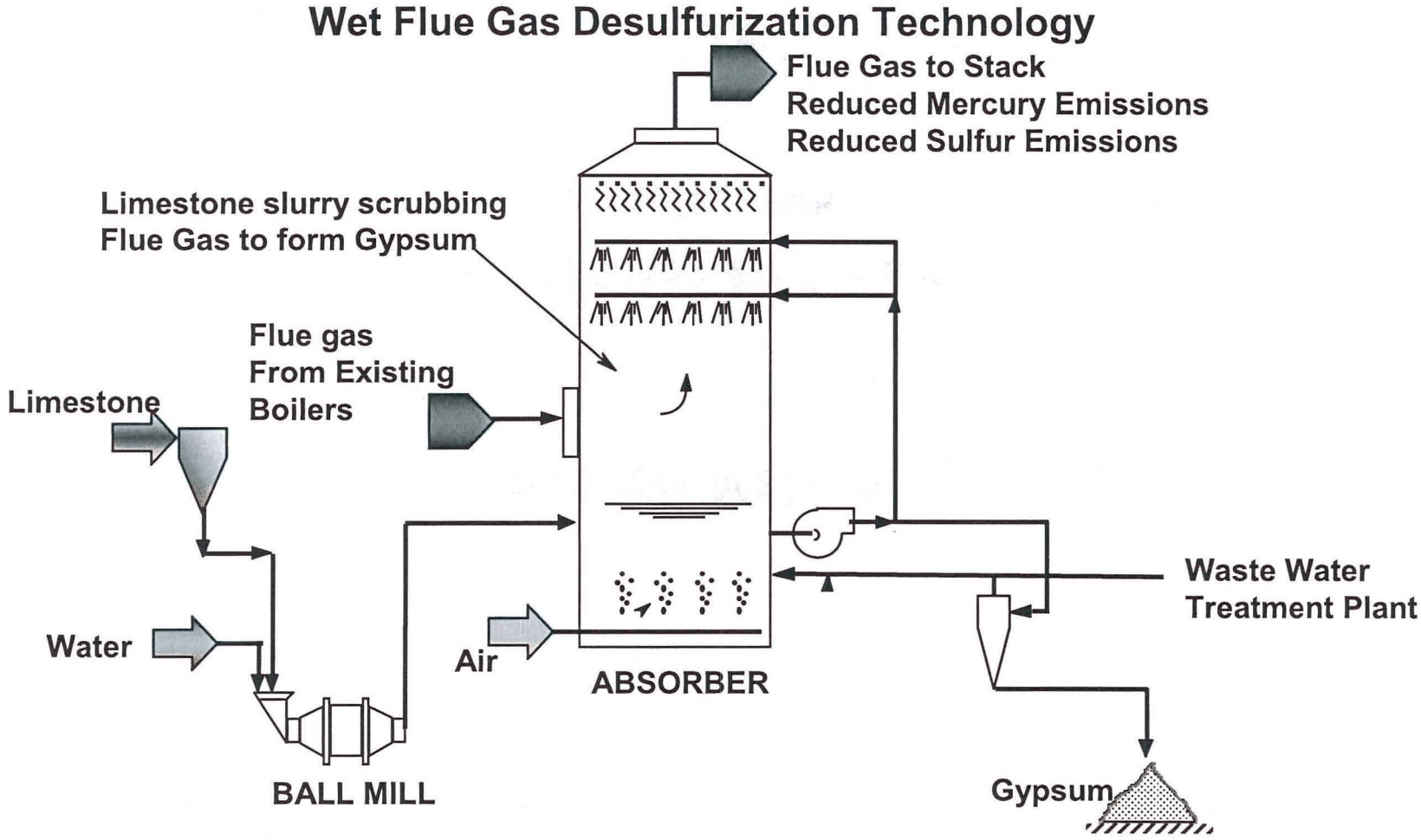
Scrubber Schematic

Clean Air Project
Merrimack Station



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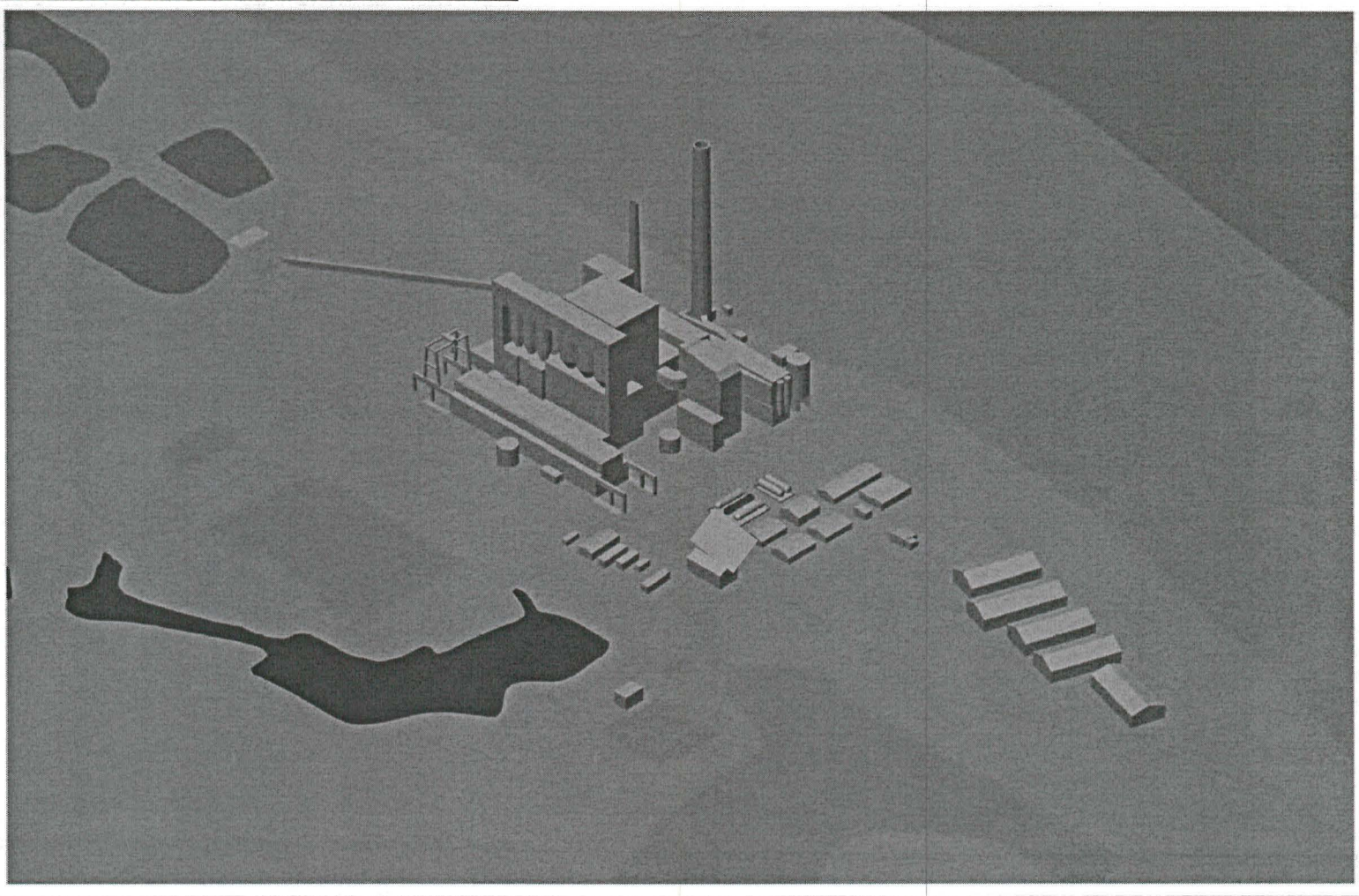
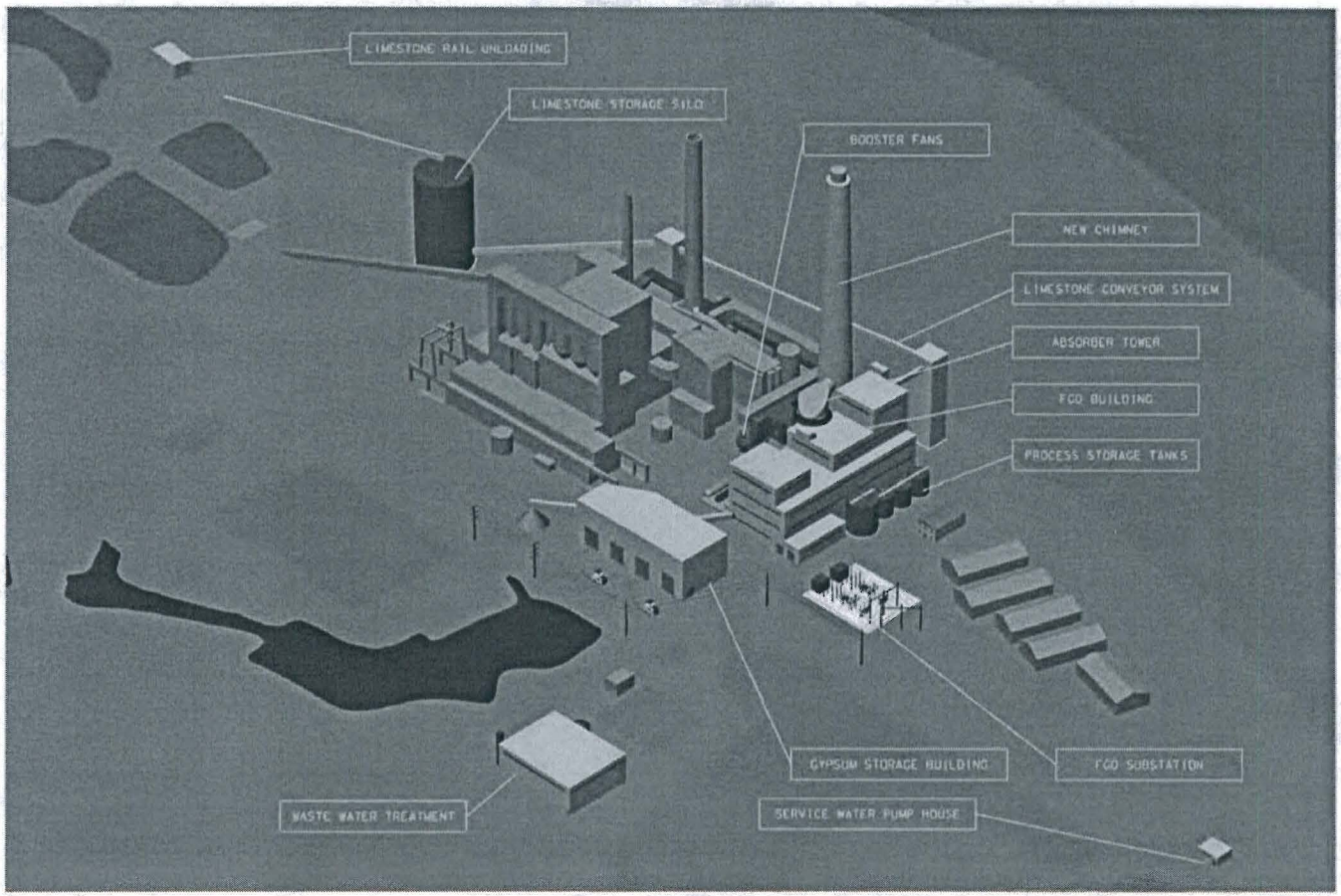
Merrimack Station: 2008

Clean Air Project
Merrimack Station



Merrimack Station: 2013

Clean Air Project
Merrimack Station



Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Remaining bids received from vendors are significantly higher than expected related to material and handling costs. Note: The bids on the major equipment have been received.	2008	$10 million	20%	$2 million	Currently carrying out the procurement schedule. The Purchasing area is trying to stimulate competition during the bid process. Lastly as the required implementation date allows for some slippage in the schedule.
Lack of sufficient, qualified construction labor results in increased costs to import labor resources, schedule delays to wait for resources to become available.	2009-12	$50 million	10%	$5 million	WGI will initiate the National Maintenance Agreement. Meetings have been held with the union trades to discuss the project and labor requirements up front.
Inability to lock in firm prices during contracting phase exposes the project to price volatility and currency risk.	2008-9	$25 million	20%	$5 million	The RFP is being structured for fixed/lump sum pricing. The contract will be negotiated to try and include these parameters.

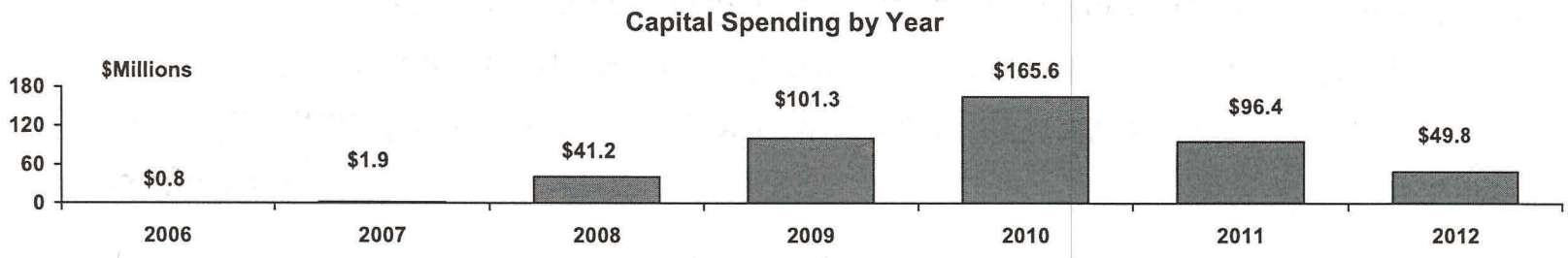
Risk Assessment, Major Risk Concerns

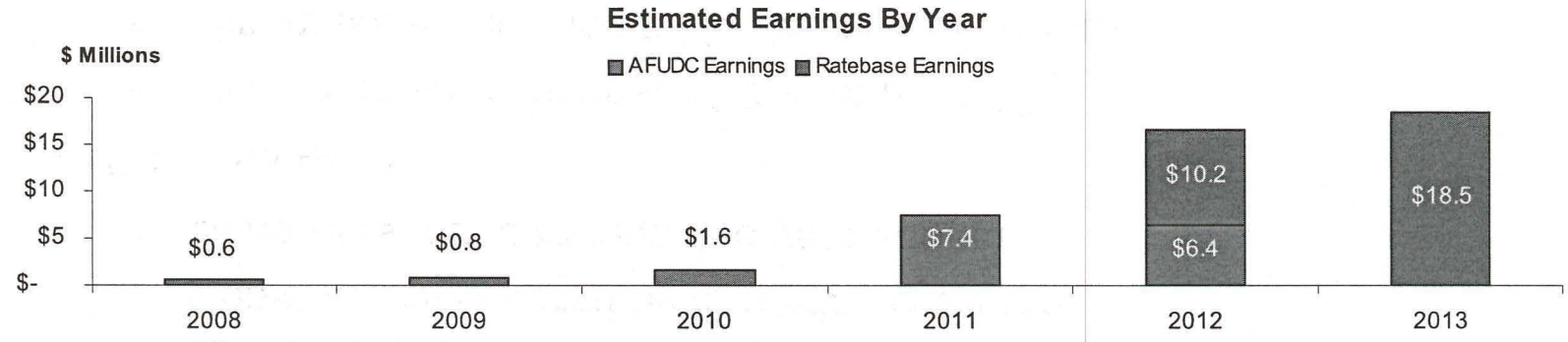
Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Vendors unable to meet project design criteria resulting in non-conforming bids. Note: bids received with mercury criteria. Risk relates to remaining design specifications.	2008-9	$25 million	25%	$6.25 million	In the event this occurs, an acceptable outcome will be negotiated during the procurement process.
Inability to design appropriate plant integration plans resulting in MK1 bypass, boiler implosion and noise issues.	2008-9	$12.5 million	50%	$6.25 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.
Scope definition changes drastically during construction resulting in additional expenditures and/or potential schedule delays.	2008-12	$18.75 million	20%	$3.75 million	PSNH team will work closely with WGI & EPC contractors to minimize the impact.
Proposed design is inadequate and does not meet operability/reliability/ constructability requirements resulting in complete redesign.	2008-9	$12.5 million	30%	$3.75 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.

Cashflow and Earnings Projection

Clean Air Project
Merrimack Station





EPS	$.00	$.00	$.01	$.02	$.03	$.04

Assumptions:

- Base-case project costs are estimated at $457M
- Project expected to be in-service on June 30, 2012
- Assumes 9.81% ROE on 47.23% of Capital Structure
- Average Shares outstanding per 2009-2013 Forecast

Project Benefits are Accentuated by Advancing the In-Service Date to mid-2012

Clean Air Project
Merrimack Station

- Financial
  - Reduces AFUDC cost by $10 Million
  - Limits exposure to material or labor cost escalation for project elements not covered by firm price contracts
  - Generates real earnings one year sooner
- Environmental
  - Eliminates an additional 31,350 tons of SO_2
  - Eliminates an additional 229 pounds of Mercury
  - Reduces particulate emissions to less than 1% one year sooner
- Customer
  - Produces "early reduction mercury credits" that can be used for
    - Compliance in future years if operational issues with the scrubber arise
    - Conversion to fungible SO_2 allowances (estimated at 12,500 allowances)

FOR APPROVAL BY THE
NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE

June 25, 2008

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT

ISSUE:

The Northeast Utilities Risk and Capital Committee (RaCC) provides oversight and input for capital programs and projects exceeding $10 million. The PSNH Clean Air Project was brought to RaCC on May 30, 2007 for conceptual project review and initial funding approval, and for revised initial funding approval on September 24, 2007.

Consistent with the NU RaCC Charter, the PSNH Clean Air Project is being brought to the RaCC for review and recommendation for approval to the Chairman, President and CEO (CEO) of NU and Chairman of Public Service Company of New Hampshire.

RECOMMENDATION:

RECOMMEND CEO AND CHAIRMAN APPROVES THE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT CAPITAL FUNDING:

The RaCC recommends that the CEO and Chairman of PSNH approve the expenditure of $457 million of capital funding, inclusive of funds spent to date as provided for in the attached material.

ATTACHMENTS:

Presentation entitled "The Public Service Company of New Hampshire Clean Air Project".

RaCC resolution recommending CEO and Chairman approval of capital funding for the PSNH Clean Air Project.

Northeast Utilities
Risk and Capital Committee Meeting
June 25, 2008

RECOMMEND APPROVAL OF CAPITAL FUNDING FOR THE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT BY THE CEO OF NU AND THE CHAIRMAN OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE.

WHEREAS, Public Service Company of New Hampshire ("PSNH") management provided the Committee with a capital project approval proposal for the PSNH Clean Air Project and have requested $457 million of capital funding, inclusive of funds spent to date; and

WHEREAS, this Committee has reviewed said proposal;

NOW THEREFORE, BE IT

RESOLVED, that this Committee finds the following capital funding by Public Service Company of New Hampshire ("PSNH") of the PSNH Clean Air Project as described in the material submitted to this meeting and ordered filed with its records thereof acceptable.

Project	Total Cost	Year of Completion
PSNH Clean Air Project	$457 million, inclusive of funds spent to date	2012

RESOLVED, that this Committee recommends that the Chairman of the Board, President and Chief Executive Officer of Northeast Utilities and the Chairman of PSNH approve the capital funding by PSNH of the PSNH Clean Air Project, provided however that this Committee further recommends that a status update on the project be submitted to the Committee no less frequently than quarterly and the capital funding by PSNH set forth above shall not be exceeded without prior approval by the Committee.

APPROVAL OF CAPITAL FUNDING FOR THE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT BY THE CEO OF NU AND THE CHAIRMAN OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE.

Approved as recommended by the Risk and Capital Committee on June 25, 2008 as set forth above:

NORTHEAST UTILITIES

Date: 9/24/08

By: Charles W. Shivery
Charles W. Shivery
Chairman of the Board, President
And Chief Executive Officer

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Date: 9/24/08

By: Charles W. Shivery
Charles W. Shivery
Chairman

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-04
Dated: 08/31/2012
Q-TC-024

Witness: **William H. Smagula**
Request from: **TransCanada**

Question:
Reference the PSNH response to TC 2-13 in this docket, please provide any written documents that were provided to the Staff, the OCA and the Office of Energy and Planning in connection with the briefings described in this response.

Response:
Please see the attached presentation.

Public Service
of New Hampshire

The Northeast Utilities System

Clean Air Project
Merrimack Station

Public Service Company of New Hampshire
Clean Air Project

Update to NHPUC Staff and
Office of Consumer Advocate

July 30, 2008

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Purpose of Today's Meeting

Clean Air Project
Merrimack Station

- Recap NH Clean Power Act and Mercury Law requirements
- Define Merrimack Station benefits to PSNH customers
- Advise as to project status within NU/PSNH
- Update cost estimates
- Confirm financial assessment of customer benefit post-scrubber installation
- Provide current thinking on project schedule

Executive Summary

Clean Air Project
Merrimack Station

- New Hampshire legislation mandates compliance with mercury emissions standards set forth in the NH Mercury Reduction Law
  - PSNH must capture 80% of mercury emissions from its coal plants by June 2013
  - Wet scrubber technology will reduce power plant mercury emissions required by New Hampshire law and is the technology specified by the law
  - There is no other technology that will guarantee capture of 80% of the mercury input of our coal fleet
  - On behalf of its customers, PSNH is incented to reduce mercury emissions prior to June 30, 2013
- Cost estimates have been defined by a competitive bidding process
  - Prices have escalated from original estimates made in 2006 due to much higher raw material pricing and higher costs of engineering services and labor
- Bid proposals indicate that an in-service date of mid-2012 is achievable
  - Earlier in-service date reduces cost (AFUDC) and risks, and allows PSNH's customers to take advantage of incentives built into the New Hampshire legislation for "early reductions" of mercury
- Despite the capital cost increases, Merrimack Station remains economic for customers under expected conditions
  - The NPV of Revenue Requirements of adding the scrubber versus replacing Merrimack Station energy and capacity supply with market purchases is a benefit to customers of $132 million
- In addition to the mercury removal benefits, the scrubber avoids about 30,000 tons of sulfur emissions and sulfur allowance purchases annually, included in the customer benefit above

Public Service of New Hampshire

Clean Air Project
Merrimack Station

Background

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Merrimack Station Benefits PSNH's Customers

Clean Air Project
Merrimack Station

- Merrimack Station produces 3 million MWh of low-cost power annually, about 35% of PSNH's total energy service requirement. The low-cost energy produced at Merrimack Station offsets the higher cost of market purchases in the overall energy service rate
- Historic high Capacity Factor and cost-effective operation of Merrimack Station has been one of the major reasons why PSNH's energy service rate is the lowest in the region, as much as 25% lower than the region's average energy service rate
- Merrimack Station has control technology to satisfy NOx and particulate emissions requirements. With a scrubber, SO_2 and mercury emissions will be controlled and Merrimack will be among the cleanest coal-burning plants in the nation
- Coal is the most abundant domestic fossil fuel resource in the United States, supplying more than 50% of the nation's power generation, but only 15% of New England's generation. Maintaining the use of this secure fuel resource is important for the diversity of the region's future energy supply
- Historically, coal has maintained a price advantage over oil or natural gas as a fuel source for the power generation sector. Operated as regulated generation, this cost savings flows directly to customers

Continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the ISO-NE region, while providing PSNH's customers with low-cost energy.

Regional Barriers to Adding New Base-Load Generation in New England Cause Merrimack Station to be Strategically Positioned for Re-Investment

Clean Air Project
Merrimack Station

- New base-load power plants (coal, nuclear, IGCC) are not on the near- or mid-term horizon for the region, making re-investment in environmental technology at existing assets the necessary strategy to maintain appropriate base-load supply
- In addition to the support these barriers provide for continued operation of existing base-load plants:
  - Brattle Group analysis of future NE energy markets indicates that all coal generation, including Merrimack, will continue to operate economically
  - Operation of Merrimack Station on coal increases NE's fuel diversity, enhancing the stability of power supply in the region
- ISO-NE market rules, and the current economic climate, make it nearly impossible for prospective generators to secure financing and overcome the substantial "barriers to entry" to build new generation in the region

Public Service of New Hampshire

Clean Air Project
Merrimack Station

Project Status Update

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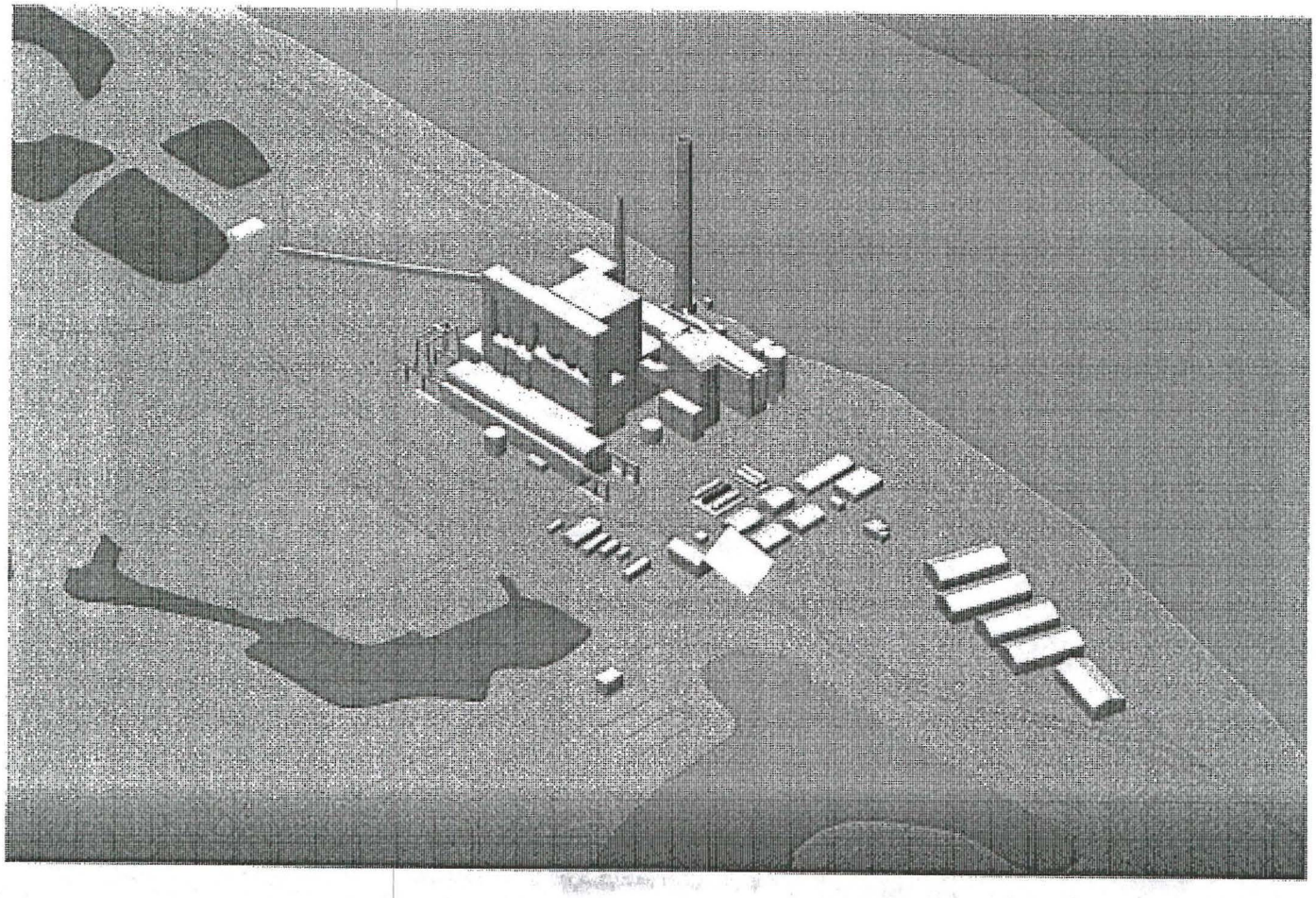
Merrimack Station: 2008

Clean Air Project
Merrimack Station



Public Service
of New Hampshire

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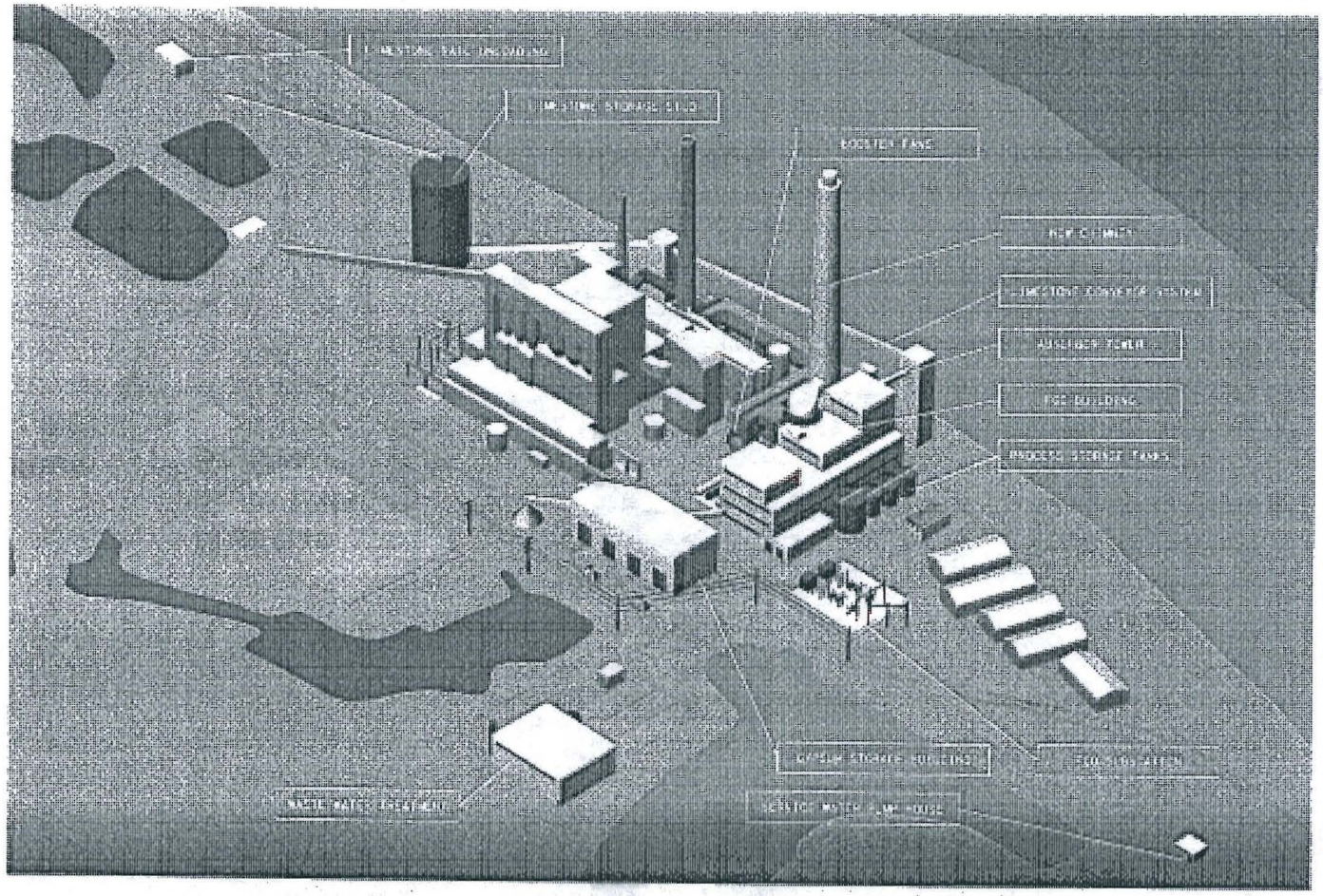
Merrimack Station: 2013

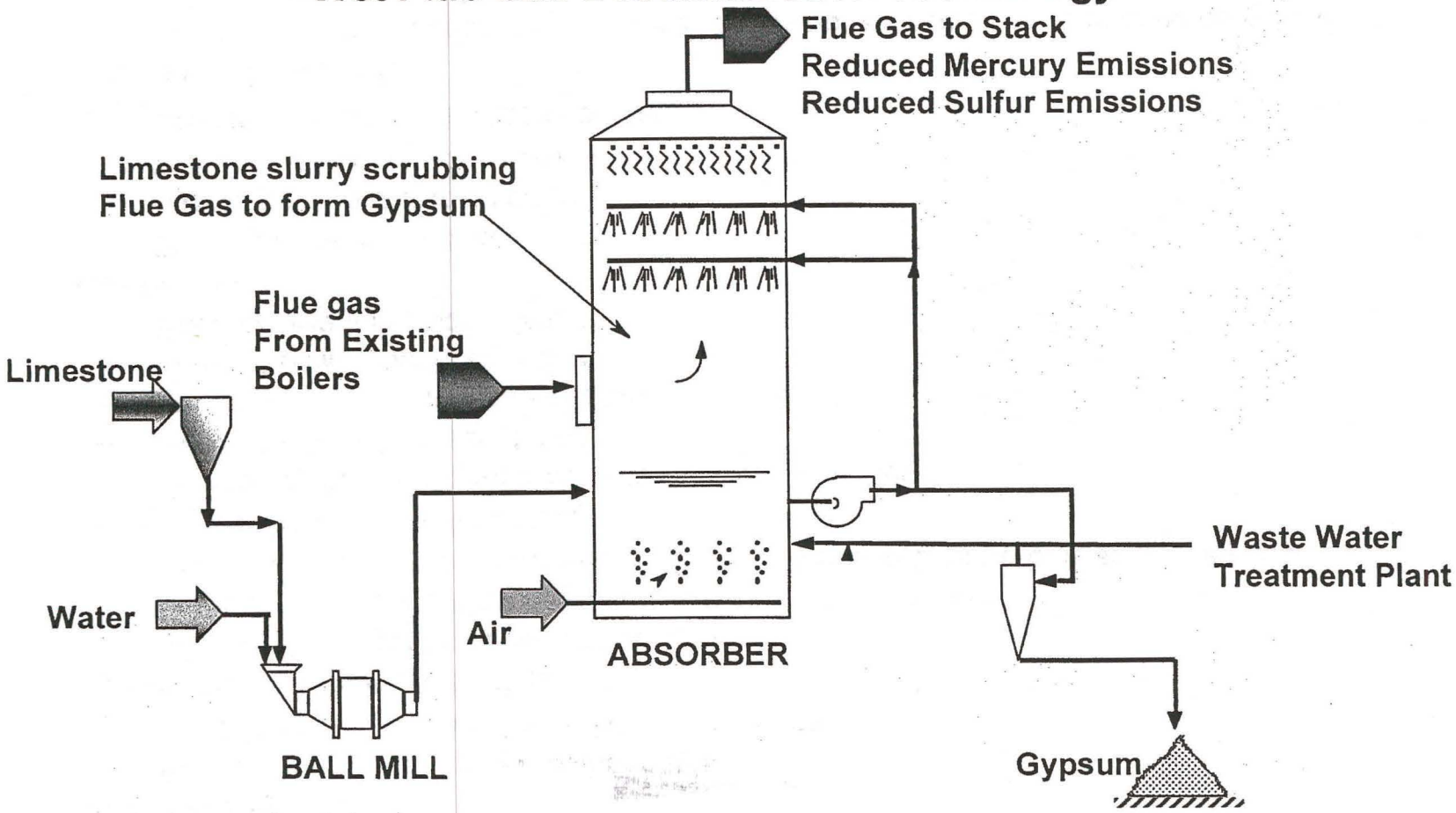
Clean Air Project
Merrimack Station



Scrubber Schematic

Clean Air Project
Merrimack Station

Wet Flue Gas Desulfurization Technology



Clean Air Project – Progress to Date

Clean Air Project
Merrimack Station

- **Engineering**
  - Projects defined in 5 major components
  - Specifications developed for 4 key components
- **Commercial and Purchasing**
  - Program Manager hired September 2007
  - Scrubber Island and Chimney proposals are in negotiations
  - Wastewater Treatment Facility and Material Handling System bids are in negotiations
- **Review, Permits, and Approvals**
  - Temporary Air permit application to NHDES, June 2007
  - NHDES – May 12 presentation
  - Temporary Air Permit expected October 2008
  - Town of Bow – local permitting
  - Regional Planning Commission
- **Site Work**
  - Existing oil tank removed
  - Site surveys and studies completed
  - Warehouse construction underway
  - On-site engineering facilities completed
- **Costs and Schedule**
  - Project costs now updated with review of all major equipment bids nearing completion
  - Original plan: Tie-ins: MK#1 Fall 2012, MK#2 Spring 2013
  - Program Manager and suppliers can support in-service one year earlier

Estimate of Project Costs

Clean Air Project
Merrimack Station

- Project estimated to cost $457M
  - Estimate based on firm price bids, currently in final phase of negotiations
  - Cost components:

→ Major Components (FGD, Material Handling, Wastewater Treatment and Chimney)	$173M
→ PSNH and Program Manager Costs (Engineering)	$170M
→ Project Contingencies	$ 52M
→ Corporate Costs (AFUDC, Indirects)	$ 62M
TOTAL Project Costs	$457M

Key Drivers of Project Cost Increase

- Scrubber design criteria for Mercury vs. SO_2
- Material cost increases
- Labor cost increases
- Engineering, including site congestion and interconnection of two dissimilar sized units into one scrubber

Revised Project Schedule

Clean Air Project
Merrimack Station

Project	2006	2007	2008	2009	2010	2011	2012
NH Mercury Reduction Act	▲						
Preliminary Engineering	▪▪▪▪▪▪▪▪						
Program Manager Hired		▲					
Detailed Engineering		▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪			
Major Contracts Awarded			▪▪▪				
Permitting		▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪
Preliminary Site Prep.		▪▪▪▪▪▪▪▪	▪				
Major Construction				▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪▪▪▪▪▪▪▪	▪
Testing & Commissioning						▪▪▪▪▪	
In Service							▲

Public Service of New Hampshire

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Public Service of New Hampshire

Clean Air Project
Merrimack Station

Project Benefits

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Financial Assessment

- Though environmental stewardship comes with a cost, PSNH has determined that continued operation with the scrubber installation is in the best interest of customers
  - NPV of customer benefit $132M
  - Monthly residential customer cost impact vs. alternative creates a $1.01 savings
  - 2013 Station Busbar Cost $94.55/Mwh

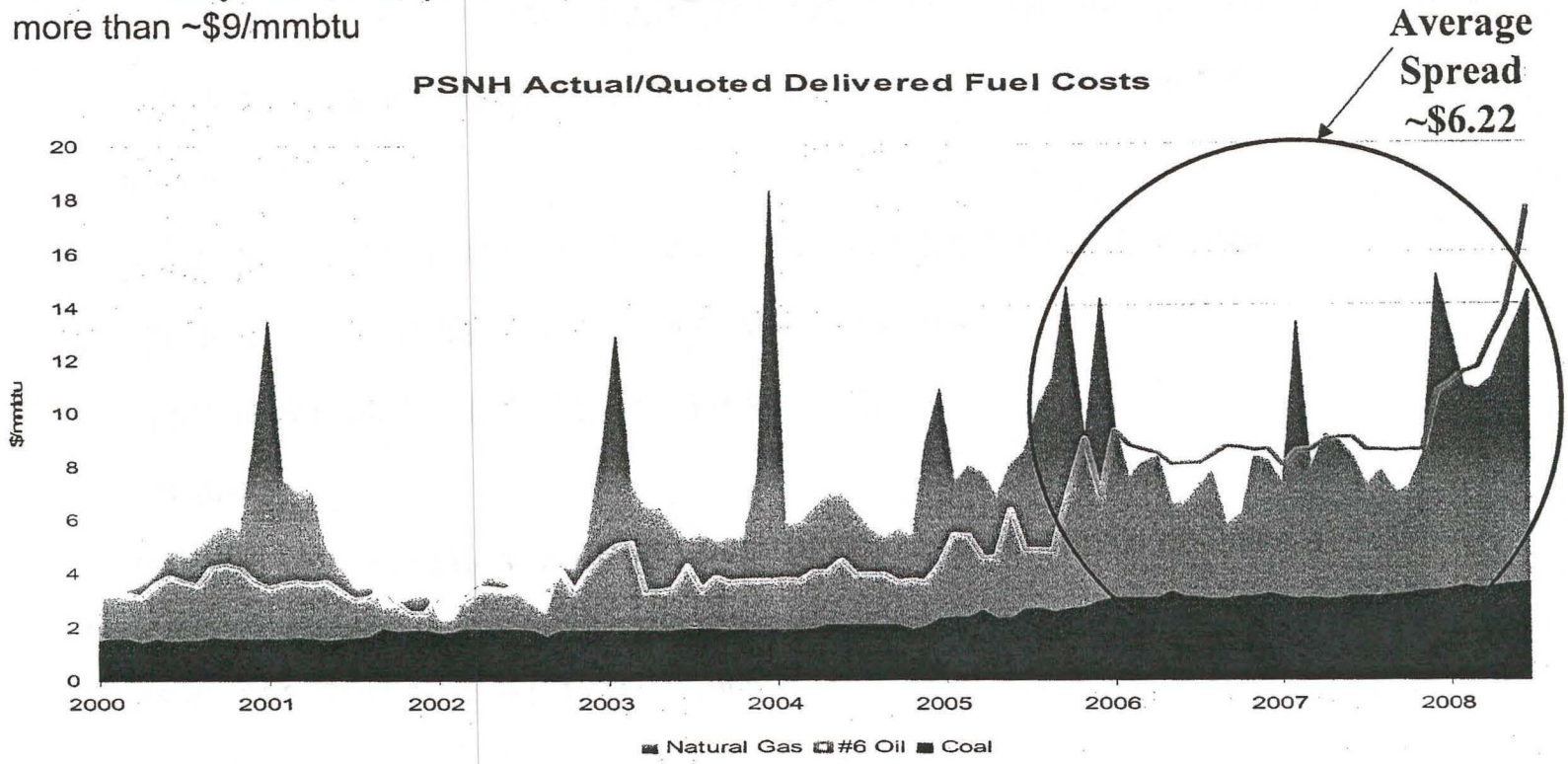
- Assumptions used in performing this analysis
  - Capital Cost $457M
  - 2012 Natural Gas Price $11.00/MMbtu
  - 2012 Coal Price $4.82/MMbtu
  - 2012 Carbon Cost (RGGI) $7.00/ton

- Our analysis shows that customer economics are most sensitive to the Coal/Natural Gas price spread and far less sensitive to capital cost or RGGI cost increases

Historic Fuel Spreads

Clean Air Project
Merrimack Station

- Gas/Coal spread has historically favored coal over natural gas and the spread has averaged $6.22/mmbtu since the hurricane season of 2005
- Since January 2007, the spread has averaged nearly $6.63/mmbtu and current spreads are more than ~$9/mmbtu



PSNH believes that coal, the nation's most plentiful domestic fuel resource, which is best suited for stationary (power generation) use, will continue to find ways to be lower cost than alternatives that are influenced predominantly by foreign supply

Project Benefits are Accentuated by Advancing the In-Service Date to Mid-2012

Clean Air Project
Merrimack Station

- Economic
  - Reduces AFUDC cost by $10 million
  - Limits exposure to material or labor cost escalation for project elements not covered by firm price contracts
- Environmental
  - Eliminates an additional 31,350 tons of SO_2
  - Eliminates an additional 229 pounds of mercury
  - Reduces particulate emissions to less than 1% one year sooner
- Customer
  - Produces "early reduction mercury credits" that can be used for:
    - Compliance in future years if operational issues with the scrubber arise
    - Conversion to fungible SO_2 allowances (estimated at 12,500 allowances)

Conclusion

Clean Air Project
Merrimack Station

- Installation of the scrubber is required by NH law to meet mercury emissions requirements
- PSNH has made significant progress, including the hiring of a Program Manager, initial permitting, and negotiation of contracts
- Merrimack Clean Air Project capital costs have increased since the original project cost estimates were prepared in 2006, following the global trend for all commodities and energy, and stand at $457M
- PSNH analysis supports that the construction and operation of a scrubber at Merrimack Station, in conformance with the NH Mercury Reduction Law, is in the best interest of PSNH's customers
- State law allows for recovery of prudently incurred costs to construct and operate the scrubber
- The project team continues to execute contracts and will begin construction in earnest late this year, with a now proposed project in-service date of mid-2012

Public Service Company of New Hampshire
Docket No. DE 11-250

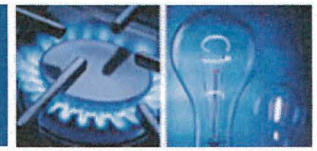
Data Request TC-03
Dated: 08/24/2012
Q-TC-009
Page 1 of 1

Witness: **Terrance J. Large**
Request from: **TransCanada**

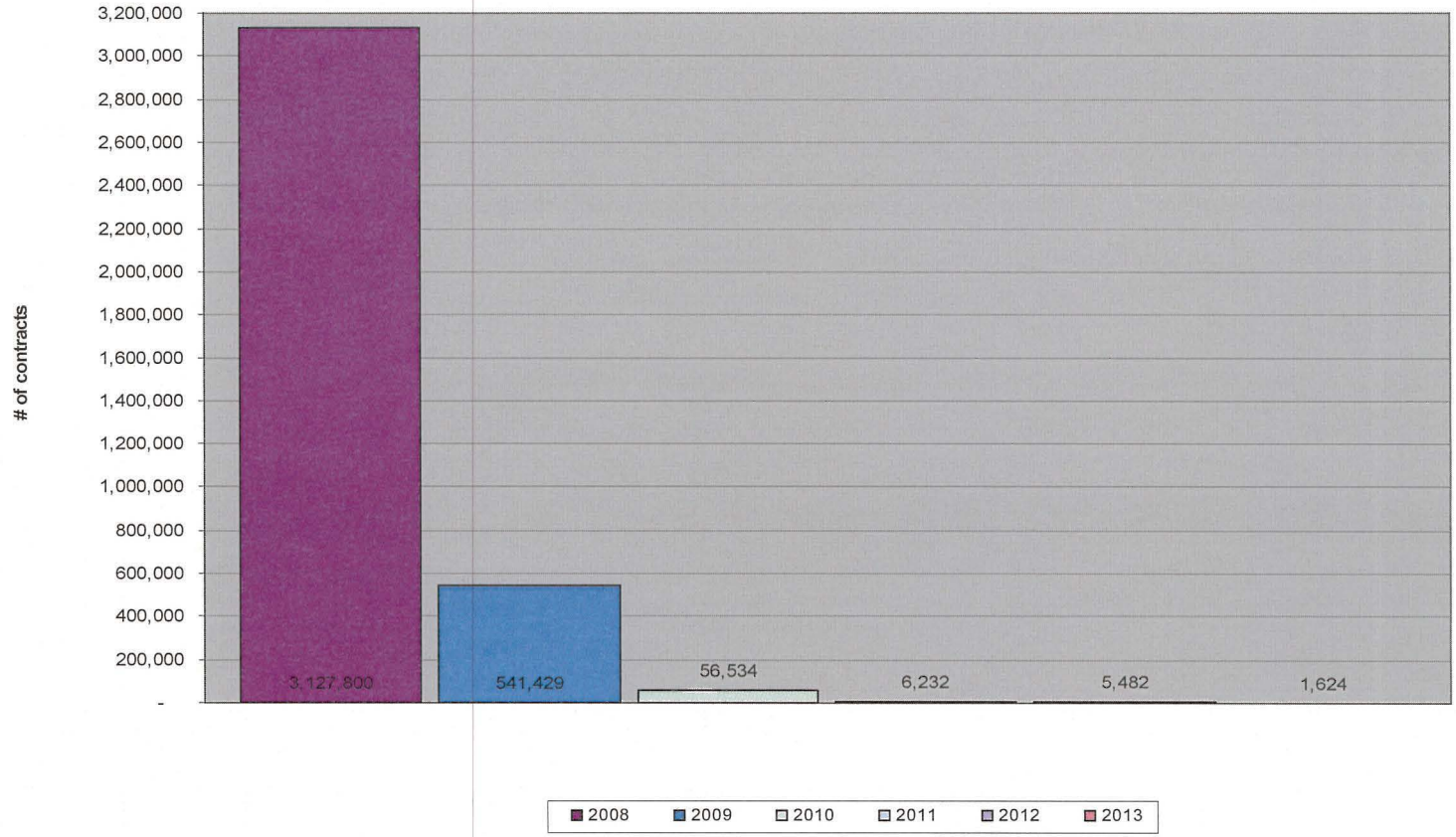
Question:
Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 15, Section IV.E please explain how PSNH arrived at the year 2012 price of $11 per MMbtu to be used as the first year price of natural gas and provide any and all documentation in PSNH's possession or the possession of any of its agents related to the choice of this price.

Response:
The 2012 price of $11/MMBtu for natural gas was selected by reviewing the NYMEX futures prices available in the summer of 2008. As shown on page 22 of the September 2, 2008 report to the NHPUC, the futures prices were $11/MMBtu in 2012.

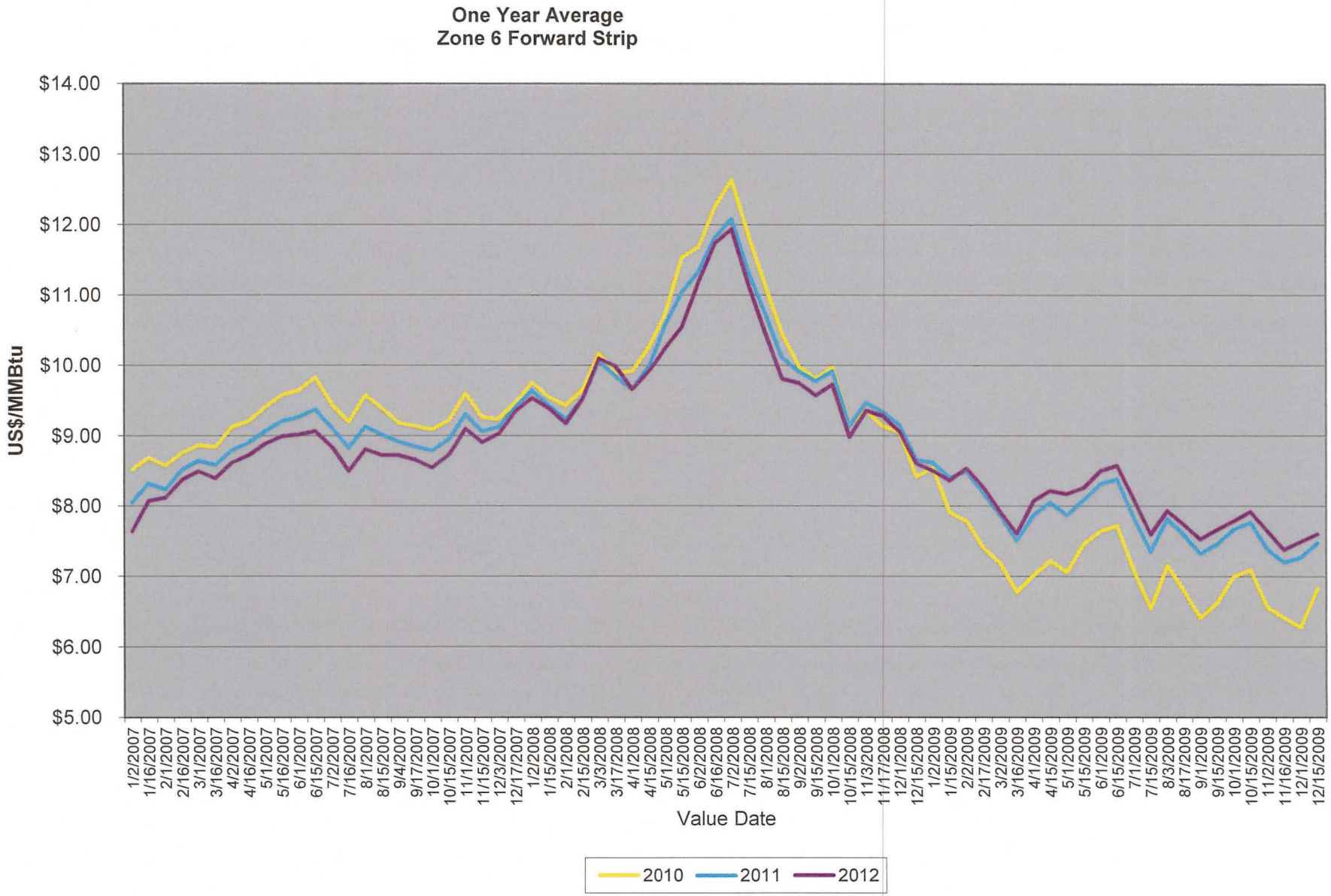
August 2008



Trade Month: August 2008
Henry Hub Contracts Sold (NYMEX)

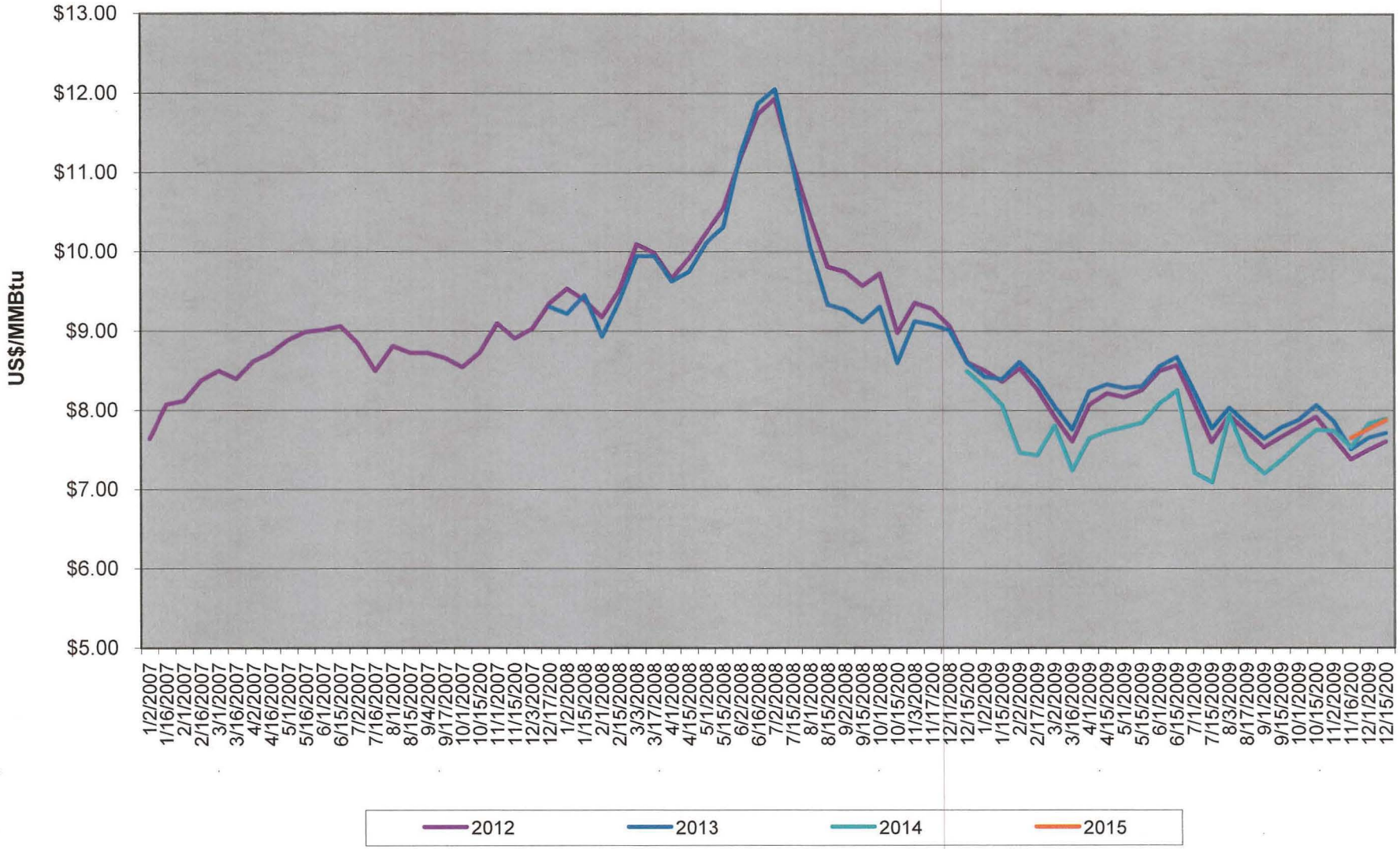


TransCanada

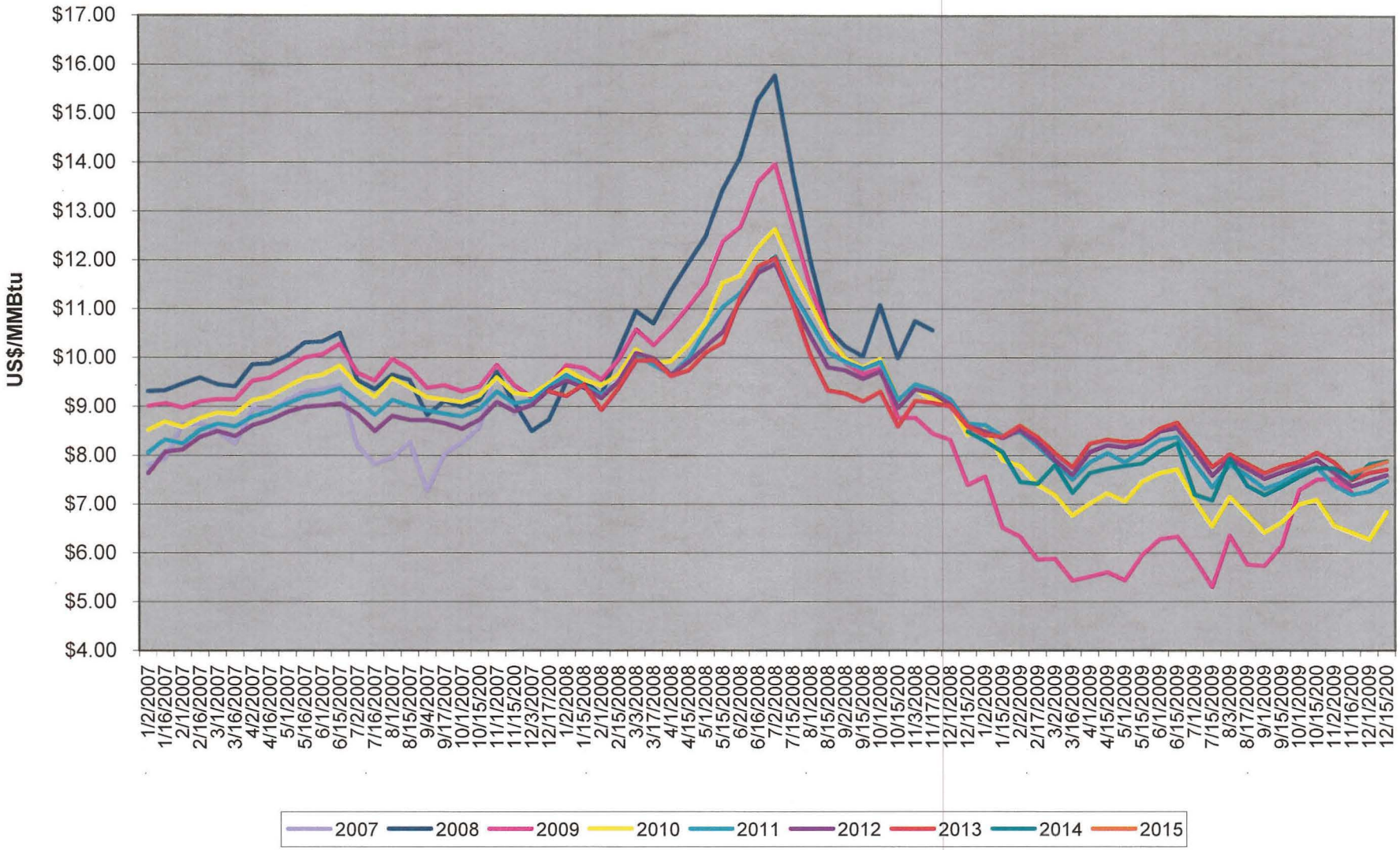


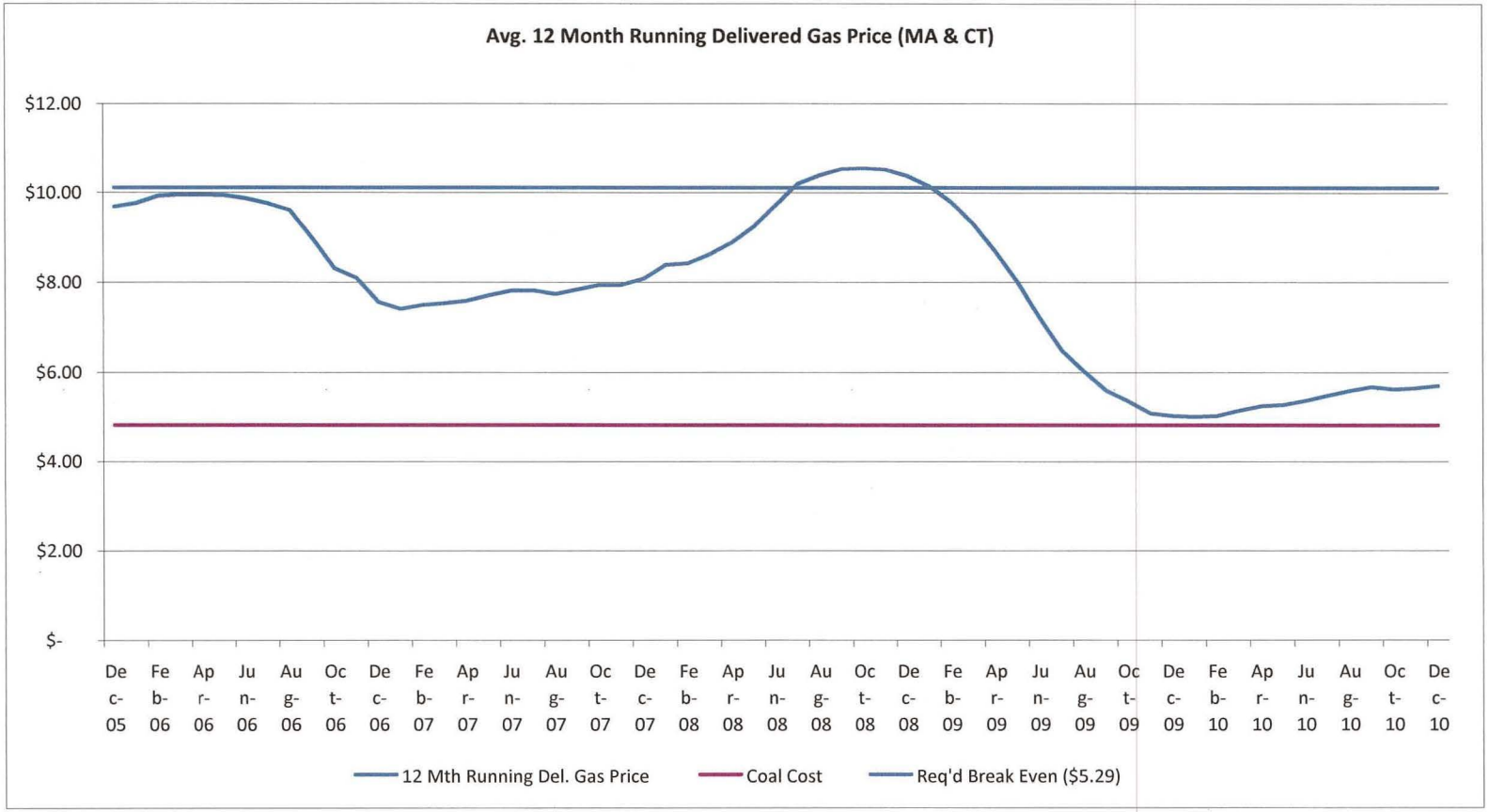
ATTACHMENT 14

One Year Average Zone 6 Forward Strip



One Year Average Zone 6 Forward Strip





ATTACHMENT 15

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-01
Dated: 06/04/2012
Q-TC-002-SP01
Page 1 of 68

Witness: **Frederick White, Jody J. TenBrock, Terrance J. Large**
Request from: **TransCanada**

Question:
(Originally numbered TC-01, Q-TC-002 in the Temporary Rates portion of this docket) Please provide all fuel price forecasts available to PSNH at the time of its initial decision to construct the flue gas scrubber at Merrimack Station.

Response:
ORIGINAL RESPONSE: PSNH objects to this question as it is based upon a faulty premise. Moreover, the information requested is irrelevant to the subject of this proceeding. Notwithstanding this objection, PSNH responds as follows:

See the response to TC-01, Q-TC-001.

SUPPLEMENTAL RESPONSE: The initial round of contracts for construction of the scrubber were signed in October, 2008. The fuel price forecasts available to PSNH at that time are provided in the attached; which includes NYMEX (natural gas) and broker (coal) forward fuel price quotations from June, 2008, and fuel price forecasts (various) received from industry consultants in February, March, July, and August, 2008. In the scrubber analyses prepared by PSNH, in advance of October, 2008, the company examined a range of values for various cost items, including fuel prices, and did not rely on a singular fuel price forecast.

NYMEX Closing Prices - June 11, 2008

$/MMBtu

Year	Natural Gas at Henry Hub	Transportation Basis from Henry Hub	
		Transco Zone 6	Tetco M-3
2008 (Jul-Dec)	12.909	1.714	1.216
2009	11.718	2.178	1.393
2010	10.596	1.919	1.325
2011	10.278	1.801	1.233
2012	10.342	1.700	1.150
2013	10.548		
2014	10.767		
2015	10.992		
2016	11.223		
2017	11.459		

ICAP
ICAP United, Inc - Coal

10-Jun-08

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Dan Vaughn @ 417-336-5582

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Matt Keck @ 502-327-1417

Nymex look-alike

Delivery	Bid - Ask Range		Last	Date
Jul	107.50	108.50	*110.00*	10-Jun
Aug	107.50	108.50	*107.75*	06-Jun
Q3 08	107.50	108.50	*110.00*	10-Jun
Q4 08	109.00	110.00	*110.25*	10-Jun
Q1 09	110.25	111.25	*111.00*	06-Jun
Q2 09	110.25	111.25	*110.75*	06-Jun
Q3 09	110.50	111.50	*112.20*	09-Jun
Q4 09	110.50	111.50	*112.50*	09-Jun
Q1 10	109.75	110.75		
CY 09	110.38	111.38	*111.00*	06-Jun
CY 10	109.25	110.25	*105.50*	05-Jun
CY 11	108.25	109.25	*est*	

CSX-BSK < 1% physical market

Bid - Ask Range		Last	Date
124.50	126.50	*120.00*	04-Jun
123.50	124.50		
123.50	124.50	*124.00 est*	10-Jun
119.50	120.50	*122.00 fin*	09-Jun
116.50	117.50	*114.00 fin*	06-Jun
115.00	116.00		
114.00	115.00		
113.50	114.50	*83.75 est*	28-Feb
112.75	113.75		
114.75	115.75	*115.00 est*	10-Jun
112.50	113.50	*108.50 fin*	29-May
108.00	109.00	*est*	

PRB 8800 - physical market

Bid - Ask Range		Last	Date
11.25	12.25	*12.00*	04-Jun
11.25	12.25		
11.25	12.25	*11.75 fin*	10-Jun
13.00	14.00	*13.50 est*	10-Jun
15.60	16.10		
16.80	17.30		
17.80	18.30		
18.80	19.30		
19.15	19.65		
17.25	17.75	*17.50*	09-Jun
19.65	20.15	*20.45*	27-May
20.15	20.65	*19.75*	03-Jun

Other Markets - Most Recent Trades

Delivery	Origin	Btu	#SO2	Last	Date
Jul	CSX	12500	1.2	*118.00*	05-Jun
Aug-Sep	NS	12500	1.2	*140.00*	06-Jun
Q3Q4	NS	12500	1.6	*121.00*	22-May
CY 09	NS	12500	1.6	*102.00*	06-May
Q1 09	NAPP rc	13000	3.0	*103.00*	15-May
CY 10	NAPP rc	13000	3.0	*103.00*	21-May
May-Aug	Mon Rvr	13000	4.5 / 5.0	*97.50*	22-Apr
May-Jul	ILB bg	11500	3.5	*74.00*	15-May
CY 09	PRB xCC	8400	0.8	*13.70*	09-Jun

Additional Market Activity

Delivery	Origin	Btu	#SO2	Bid	Ask

SO2

	Bid	Ask
2008	320	330
2009	319	329
2010	177	182
2011	167	173

Seasonal NOx

Bank	600	675
2008	750	775
2009	600	675
2010	550	700

Annual NOx

2009	4500	5000
2010	2100	2600
2011	1850	2350

SO2
2008 trades 11x, 315 -330

The Daily Scoreboard

Nymex
Jun-Jul trades 110
Q3 trades 110
Q4 trades 112 (10), 111 (2x), 110.25

CSX fin / Nym
CY 09 trades 4.25

CSX 1% phys
Aug-Sep over Oct-Nov trades 4.00

PRB 8800 fin
Q4 / Q3 trades 1.75
CY 09 17.50 (10k), 17.75 (10k), 17.50 (10k)

Vaughn's View of the U.S. Coal Markets - a perspective provided by Dan Vaughn to assist in marking coals to market

PRB Coal

Origin	10-Jun-08 Btu	#SO2	Prompt Jul	PM + 1 Aug	PQ Q3 08	PQ + 1 Q4 08	PQ + 2 Q1 09	PQ + 3 Q2 09	PQ + 4 Q3 09	PY CY 09	PY + 1 CY 10	PY + 2 CY 11
BNSF / UP	8800	0.8	11.75	11.75	11.75	13.50	#REF!	#REF!	#REF!	17.50	19.90	20.40
BNSF / UP	8400	0.8	10.00	10.15	10.15	10.50	#REF!	#REF!	#REF!	13.40	15.50	16.00

CAPP Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
BS Rvr	12000	1.2	111.67	111.50	111.50	113.00	114.25	114.25	114.50	114.38	112.75	111.75
Nymex	12000	1.7	108.00	108.00	108.00	109.50	110.75	110.75	111.00	110.88	109.75	108.75
BS Rvr	11500	1.8	101.76	102.00	102.00	103.50	105.00	105.00	105.25	105.13	104.50	103.75
CSX-BSK	12500	1.2	128.35	126.75	126.75	122.75	120.00	118.50	117.50	118.25	116.00	111.50
CSX-BSK	12500	1.6	125.50	124.00	124.00	120.00	117.00	115.50	114.50	115.25	113.00	108.50
NS-T/K	12500	1.2	145.00	142.50	142.50	141.50	131.50	130.00	129.00	129.75	126.00	120.00
NS-T/K	12500	1.6	127.00	126.50	126.50	125.50	122.50	121.00	120.00	120.75	118.50	114.00

NAPP Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
MGA	13000	3.0 / 3.4	107.00	107.00	107.00	107.00	106.00	105.00	105.00	105.25	103.00	98.50
MGA	13000	4.0 / 4.5	100.25	100.50	100.50	100.50	99.50	98.50	98.50	98.75	96.50	92.00
Mon Rvr	13000	4.5 - 5.0	102.50	102.50	102.50	102.50	101.50	100.50	100.50	100.75	98.50	94.00
U. OH Rvr	12200	6.5	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.75

ILB Barge Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
L. OH Rvr	12000	2.0	84.00	84.00	84.00	84.00	83.00	83.00	83.00	83.00	83.00	83.00
L. OH Rvr	12000	5.0	74.00	74.00	74.00	74.00	73.00	73.00	73.00	73.00	73.00	73.00

Colorado Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
UP	11800	1.0	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
UP	11300	1.0	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00

International API Markets ($/tonne)

Origin	kCal	# SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
API 2	6000	1.7	176.00	176.00	176.00	176.00	174.00	170.25	166.25	169.00	166.00	163.25
API 4	6000	1.7	137.00	138.25	139.00	140.00	140.50	140.50	140.50	140.50	140.50	141.75

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The bid - ask spread is not to be construed as the actual bid -ask in the market but rather reflects the relative bid - ask range for the Nymex, CSX and PRB markets.
All trades are based on market information reported to ICAP United by market participants. Information is believed to be reliable but cannot be guaranteed.

PETROLEUM PRODUCT PRICES FORECAST

No. 2 Fuel Oil (0.2% Sulfur)

$/MMBtu (Connecticut)

	Current $				Percent Change			
Year	Residential	Commercial	Industrial	Electric	Residential	Commercial	Industrial	Electric
1970	$1.48	$1.09	$0.73	$0.37				
1971	$1.56	$1.16	$0.77	$0.54	5.4%	6.4%	5.5%	45.9%
1972	$1.56	$1.16	$0.77	$0.91	0.0%	0.0%	0.0%	68.5%
1973	$1.77	$1.38	$0.99	$1.29	13.5%	19.0%	28.6%	41.8%
1974	$2.88	$2.46	$2.24	$2.28	62.7%	78.3%	126.3%	76.7%
1975	$2.84	$2.44	$2.41	$2.36	-1.4%	-0.8%	7.6%	3.5%
1976	$3.04	$2.62	$2.52	$2.40	7.0%	7.4%	4.6%	1.7%
1977	$3.40	$2.96	$2.78	$2.38	11.8%	13.0%	10.3%	-0.8%
1978	$3.61	$3.12	$2.88	$2.00	6.2%	5.4%	3.6%	-16.0%
1979	$5.19	$4.59	$4.01	$3.64	43.8%	47.1%	39.2%	82.0%
1980	$7.07	$6.37	$5.75	$6.13	36.2%	38.8%	43.4%	68.4%
1981	$8.77	$8.04	$6.93	$7.78	24.0%	26.2%	20.5%	26.9%
1982	$8.53	$7.80	$7.74	$7.31	-2.7%	-3.0%	11.7%	-6.0%
1983	$8.46	$7.46	$7.42	$6.28	-0.8%	-4.4%	-4.1%	-14.1%
1984	$8.69	$7.41	$6.95	$6.21	2.7%	-0.7%	-6.3%	-1.1%
1985	$8.37	$7.07	$6.75	$5.88	-3.7%	-4.6%	-2.9%	-5.3%
1986	$6.90	$4.97	$4.43	$3.59	-17.6%	-29.7%	-34.4%	-38.9%
1987	$6.46	$4.88	$4.88	$4.01	-6.4%	-1.8%	10.2%	11.7%
1988	$6.61	$4.65	$4.67	$3.64	2.3%	-4.7%	-4.3%	-9.2%
1989	$7.23	$5.51	$5.54	$4.26	9.4%	18.5%	18.6%	17.0%
1990	$8.55	$6.80	$6.77	$5.67	18.3%	23.4%	22.2%	33.1%
1991	$8.27	$6.09	$5.93	$4.92	-3.3%	-10.4%	-12.4%	-13.2%
1992	$7.24	$5.45	$5.11	$4.82	-12.5%	-10.5%	-13.8%	-2.0%
1993	$7.02	$5.22	$5.06	$4.12	-3.0%	-4.2%	-1.0%	-14.5%
1994	$6.80	$5.01	$4.78	$3.82	-3.1%	-4.0%	-5.5%	-7.3%
1995	$6.60	$4.94	$4.77	$3.82	-2.9%	-1.4%	-0.2%	0.0%
1996	$7.54	$5.77	$5.91	$4.76	14.2%	16.8%	23.9%	24.6%
1997	$7.36	$5.54	$5.49	$4.88	-2.4%	-4.0%	-7.1%	2.5%
1998	$6.35	$4.48	$4.52	$3.28	-13.7%	-19.1%	-17.7%	-32.8%
1999	$6.51	$4.86	$4.86	$4.03	2.5%	8.5%	7.5%	22.9%
2000	$9.87	$7.73	$7.71	$6.81	51.6%	59.1%	58.6%	69.0%
2001	$9.47	$7.32	$6.69	$5.79	-4.1%	-5.3%	-13.2%	-15.0%
2002	$8.54	$6.87	$6.31	$5.29	-9.8%	-6.1%	-5.7%	-8.6%
2003	$10.36	$8.12	$7.58	$6.85	21.3%	18.2%	20.1%	29.5%
2004	$11.60	$9.87	$9.58	$6.43	12.0%	21.6%	26.4%	-6.1%
2005	$15.80	$13.64	$13.25	$12.29	36.2%	38.2%	38.3%	91.2%
2006	$17.20	$14.99	$14.60	$13.62	8.9%	10.0%	10.2%	10.8%
2007	$18.93	$16.68	$16.28	$15.28	10.0%	11.2%	11.5%	12.2%
2008	$22.22	$19.93	$19.53	$18.51	17.4%	19.5%	20.0%	21.2%
2009	$21.66	$19.34	$18.93	$17.90	-2.5%	-3.0%	-3.1%	-3.3%
2010	$21.50	$19.14	$18.72	$17.68	-0.8%	-1.0%	-1.1%	-1.2%
2011	$21.77	$19.38	$18.96	$17.90	1.3%	1.3%	1.3%	1.2%
2012	$22.37	$19.95	$19.52	$18.45	2.8%	2.9%	3.0%	3.1%
2013	$22.98	$20.53	$20.09	$19.00	2.7%	2.9%	2.9%	3.0%
2014	$23.60	$21.12	$20.68	$19.57	2.7%	2.9%	2.9%	3.0%
2015	$24.24	$21.73	$21.28	$20.16	2.7%	2.9%	2.9%	3.0%
2016	$24.89	$22.34	$21.89	$20.75	2.7%	2.8%	2.9%	2.9%
2017	$25.82	$23.24	$22.78	$21.63	3.7%	4.0%	4.1%	4.2%
2018	$26.79	$24.17	$23.71	$22.54	3.8%	4.0%	4.1%	4.2%

Note: 1989-1998 data was updated using the latest figures from the Master Oil and Gas Database
Basis differences for 1989-1995 were taken from actual data

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Annual

$/MMBtu (Connecticut)

Year	Current $			Percent Change		
	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1970	$0.42	$0.43	$0.38			
1971	$0.59	$0.61	$0.54	40.5%	41.9%	42.1%
1972	$0.70	$0.66	$0.65	18.6%	8.2%	20.4%
1973	$0.83	$0.79	$0.85	18.6%	19.7%	30.8%
1974	$2.00	$2.02	$2.06	141.0%	155.7%	142.4%
1975	$1.97	$2.12	$2.02	-1.5%	5.0%	-1.9%
1976	$1.87	$2.08	$1.94	-5.1%	-1.9%	-4.0%
1977	$2.22	$2.31	$2.24	18.7%	11.1%	15.5%
1978	$2.11	$2.34	$2.13	-5.0%	1.3%	-4.9%
1979	$3.35	$3.41	$3.32	58.8%	45.7%	55.9%
1980	$4.59	$4.55	$4.70	37.0%	33.4%	41.6%
1981	$5.49	$5.74	$5.56	19.6%	26.2%	18.3%
1982	$4.67	$4.88	$4.75	-14.9%	-15.0%	-14.6%
1983	$4.51	$4.67	$4.54	-3.4%	-4.3%	-4.4%
1984	$5.25	$5.25	$4.84	16.4%	12.4%	6.6%
1985	$4.68	$4.68	$4.24	-10.9%	-10.9%	-12.4%
1986	$2.79	$2.79	$2.51	-40.4%	-40.4%	-40.8%
1987	$3.12	$3.12	$2.93	11.8%	11.8%	16.7%
1988	$2.57	$2.57	$2.40	-17.6%	-17.6%	-18.1%
1989	$3.04	$3.04	$2.85	18.3%	18.3%	18.8%
1990	$3.25	$3.25	$3.01	6.9%	6.9%	5.6%
1991	$2.69	$2.69	$2.47	-17.2%	-17.2%	-17.9%
1992	$2.53	$2.53	$2.40	-5.9%	-5.9%	-2.8%
1993	$2.66	$2.66	$2.39	5.1%	5.1%	-0.4%
1994	$3.16	$3.16	$2.52	18.8%	18.8%	5.4%
1995	$3.38	$3.38	$2.63	7.0%	7.0%	4.4%
1996	$3.90	$3.90	$3.21	15.4%	15.4%	22.1%
1997	$3.15	$3.15	$2.92	-19.2%	-19.2%	-9.0%
1998	$2.46	$2.46	$2.18	-21.9%	-21.9%	-25.3%
1999	$2.55	$2.55	$2.23	3.7%	3.7%	2.3%
2000	$4.36	$4.36	$3.27	71.0%	71.0%	--
2001	$4.04	$4.04	$3.37	-7.3%	-7.3%	--
2002	$4.67	$4.67	$3.67	15.6%	15.6%	8.9%
2003	$5.40	$5.40	$3.74	15.6%	15.6%	1.9%
2004	$5.64	$5.64	$3.96	4.4%	4.4%	5.9%
2005	$7.42	$7.42	$6.62	31.5%	31.5%	67.3%
2006	$8.31	$8.31	$7.50	12.1%	12.1%	13.2%
2007	$9.47	$9.47	$8.64	13.9%	13.9%	15.2%
2008	$11.41	$11.41	$10.57	20.5%	20.5%	22.3%
2009	$10.94	$10.94	$10.09	-4.1%	-4.1%	-4.5%
2010	$10.71	$10.71	$9.85	-2.1%	-2.1%	-2.4%
2011	$11.26	$11.26	$10.38	5.1%	5.1%	5.4%
2012	$11.59	$11.59	$10.70	3.0%	3.0%	3.1%
2013	$11.93	$11.93	$11.03	2.9%	2.9%	3.1%
2014	$12.28	$12.28	$11.37	2.9%	2.9%	3.0%
2015	$12.63	$12.63	$11.71	2.9%	2.9%	3.0%
2016	$12.99	$12.99	$12.06	2.9%	2.9%	3.0%
2017	$13.52	$13.52	$12.58	4.1%	4.1%	4.3%
2018	$14.08	$14.08	$13.12	4.1%	4.1%	4.3%

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Annual

$/MMBtu (Connecticut)

Year	Current $			Percent Change		
	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.66	$2.66	$2.39			
1994	$3.16	$3.16	$2.52	18.8%	18.8%	5.4%
1995	$3.38	$3.38	$2.63	7.0%	7.0%	4.4%
1996	$3.90	$3.90	$3.24	15.4%	15.4%	23.2%
1997	$3.15	$3.15	$2.92	-19.2%	-19.2%	-9.9%
1998	$2.46	$2.46	$2.18	-21.9%	-21.9%	-25.3%
1999	$2.55	$2.55	$2.23	3.7%	3.7%	2.3%
2000	$4.36	$4.36	$3.27	71.0%	71.0%	--
2001	$4.04	$4.04	$3.37	-7.3%	-7.3%	--
2002	$4.67	$4.67	$3.67	15.6%	15.6%	8.9%
2003	$5.40	$5.40	$3.74	15.6%	15.6%	1.9%
2004	$5.64	$5.64	$3.96	4.4%	4.4%	5.9%
2005	$7.42	$7.42	$6.62	31.5%	31.5%	67.3%
2006	$8.31	$8.31	$7.50	12.1%	12.1%	13.2%
2007	$9.47	$9.47	$8.64	13.9%	13.9%	15.2%
2008	$11.41	$11.41	$10.57	20.5%	20.5%	22.3%
2009	$10.94	$10.94	$10.09	-4.1%	-4.1%	-4.5%
2010	$10.71	$10.71	$9.85	-2.1%	-2.1%	-2.4%
2011	$11.26	$11.26	$10.38	5.1%	5.1%	5.4%
2012	$11.59	$11.59	$10.70	3.0%	3.0%	3.1%
2013	$11.93	$11.93	$11.03	2.9%	2.9%	3.1%
2014	$12.28	$12.28	$11.37	2.9%	2.9%	3.0%
2015	$12.63	$12.63	$11.71	2.9%	2.9%	3.0%
2016	$12.99	$12.99	$12.06	2.9%	2.9%	3.0%
2017	$13.52	$13.52	$12.58	4.1%	4.1%	4.3%
2018	$14.08	$14.08	$13.12	4.1%	4.1%	4.3%

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Summer

$/MMBtu (Connecticut)

Year	Current $			Percent Change		
	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.74	$2.74	$2.47			
1994	$3.12	$3.12	$2.48	14.0%	14.0%	0.5%
1995	$3.35	$3.35	$2.60	7.5%	7.5%	5.0%
1996	$3.78	$3.78	$3.12	12.8%	12.8%	20.0%
1997	$3.06	$3.06	$2.83	-19.1%	-19.1%	-9.4%
1998	$2.53	$2.53	$2.25	-17.5%	-17.5%	-20.7%
1999	$2.72	$2.72	$2.40	7.7%	7.7%	6.8%
2000	$4.47	$4.47	--	64.6%	64.6%	--
2001	$4.01	$4.01	$3.34	-10.4%	-10.4%	--
2002	$4.93	$4.93	$3.93	23.0%	23.0%	17.7%
2003	$5.11	$5.11	$3.45	3.6%	3.6%	-12.3%
2004	$5.74	$5.74	$4.06	12.4%	12.4%	17.7%
2005	$7.76	$7.76	$6.97	35.2%	35.2%	71.6%
2006	$8.43	$8.43	$7.62	8.6%	8.6%	9.3%
2007	$10.60	$10.60	$9.77	25.7%	25.7%	28.2%
2008	$10.95	$10.95	$10.11	3.3%	3.3%	3.5%
2009	$10.60	$10.60	$9.75	-3.2%	-3.2%	-3.6%
2010	$10.50	$10.50	$9.64	-1.0%	-1.0%	-1.2%
2011	$11.03	$11.03	$10.16	5.1%	5.1%	5.4%
2012	$11.71	$11.71	$10.82	6.2%	6.2%	6.6%
2013	$12.05	$12.05	$11.15	2.9%	2.9%	3.0%
2014	$12.40	$12.40	$11.49	2.9%	2.9%	3.0%
2015	$12.75	$12.75	$11.83	2.9%	2.9%	3.0%
2016	$13.12	$13.12	$12.18	2.8%	2.8%	2.9%
2017	$13.64	$13.64	$12.70	4.0%	4.0%	4.2%
2018	$14.20	$14.20	$13.24	4.0%	4.0%	4.2%

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Winter

$/MMBtu (Connecticut)

	Current $			Percent Change		
Year	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.55	$2.55	$2.28			
1994	$3.22	$3.22	$2.58	26.0%	26.0%	12.9%
1995	$3.42	$3.42	$2.67	6.2%	6.2%	3.5%
1996	$4.06	$4.06	$3.40	18.9%	18.9%	27.6%
1997	$3.27	$3.27	$3.04	-19.4%	-19.4%	-10.5%
1998	$2.37	$2.37	$2.09	-27.7%	-27.7%	-31.4%
1999	$2.31	$2.31	$1.99	-2.3%	-2.3%	-4.5%
2000	$4.20	$4.20	--	81.5%	81.5%	--
2001	$4.08	$4.08	$3.41	-2.8%	-2.8%	--
2002	$4.30	$4.30	$3.30	5.4%	5.4%	-3.2%
2003	$5.80	$5.80	$4.14	34.9%	34.9%	25.5%
2004	$5.50	$5.50	$3.82	-5.3%	-5.3%	-7.9%
2005	$6.91	$6.91	$6.12	25.8%	25.8%	60.4%
2006	$8.14	$8.14	$7.33	17.8%	17.8%	19.8%
2007	$10.67	$10.67	$9.84	31.0%	31.0%	34.2%
2008	$12.05	$12.05	$11.22	13.0%	13.0%	13.9%
2009	$11.42	$11.42	$10.57	-5.3%	-5.3%	-5.8%
2010	$11.01	$11.01	$10.15	-3.6%	-3.6%	-4.0%
2011	$11.57	$11.57	$10.70	5.1%	5.1%	5.4%
2012	$11.42	$11.42	$10.54	-1.3%	-1.3%	-1.5%
2013	$11.76	$11.76	$10.86	3.0%	3.0%	3.1%
2014	$12.11	$12.11	$11.20	2.9%	2.9%	3.1%
2015	$12.46	$12.46	$11.54	2.9%	2.9%	3.1%
2016	$12.83	$12.83	$11.89	2.9%	2.9%	3.0%
2017	$13.36	$13.36	$12.41	4.1%	4.1%	4.3%
2018	$13.91	$13.91	$12.95	4.1%	4.1%	4.3%

DELIVERED NATURAL GAS PRICES FORECAST

$/MMBtu (Connecticut)

Year	Current $				Percent Change			
	Residential	Commercial	Industrial	Electric	Residential	Commercial	Industrial	Electric
1970	$1.88	$1.45	$1.03	$0.34				
1971	$2.04	$1.53	$1.14	$0.38	8.5%	5.5%	10.7%	11.8%
1972	$2.06	$1.59	$1.15	$0.43	1.0%	3.9%	0.9%	13.2%
1973	$2.21	$1.79	$1.24	$0.53	7.3%	12.6%	7.8%	23.3%
1974	$2.76	$2.20	$1.71	$0.63	24.9%	22.9%	37.9%	18.9%
1975	$3.28	$2.64	$2.24	$1.36	18.8%	20.0%	31.0%	115.9%
1976	$3.38	$3.20	$2.65	$1.65	3.0%	21.2%	18.3%	21.3%
1977	$4.30	$3.53	$2.94		27.2%	10.3%	10.9%	
1978	$4.42	$3.72	$3.04		2.8%	5.4%	3.4%	
1979	$4.69	$3.90	$3.25		6.1%	4.8%	6.9%	
1980	$5.72	$4.67	$4.08		22.0%	19.7%	25.5%	
1981	$6.68	$5.46	$4.97		16.8%	16.9%	21.8%	
1982	$8.29	$6.78	$5.86		24.1%	24.2%	17.9%	
1983	$9.43	$7.24	$5.76		13.8%	6.8%	-1.7%	
1984	$8.56	$6.49	$5.47	$3.71	-9.2%	-10.4%	-5.0%	
1985	$8.88	$6.59	$5.38	$3.39	3.7%	1.5%	-1.6%	-8.6%
1986	$8.57	$6.24	$4.53	$2.09	-3.5%	-5.3%	-15.8%	-38.3%
1987	$7.96	$5.59	$4.08	$2.37	-7.1%	-10.4%	-9.9%	13.4%
1988	$7.63	$5.45	$3.92	$2.17	-4.1%	-2.5%	-3.9%	-8.4%
1989	$7.98	$5.88	$4.36	$2.51	4.6%	7.9%	11.2%	15.7%
1990	$8.58	$6.30	$4.80	$2.81	7.5%	7.1%	10.2%	12.0%
1991	$8.74	$6.90	$4.84	$2.16	2.0%	9.6%	0.6%	-23.1%
1992	$8.96	$7.20	$4.92	$2.74	2.5%	4.3%	1.7%	26.9%
1993	$9.16	$6.81	$4.63	$3.79	2.2%	-5.4%	-5.8%	38.2%
1994	$9.84	$7.18	$4.36	$1.93	7.5%	5.3%	-5.9%	-49.0%
1995	$9.70	$7.34	$4.26	$1.95	-1.4%	2.3%	-2.3%	1.0%
1996	$9.79	$7.19	$4.66	$2.68	0.8%	-2.1%	9.4%	37.3%
1997	$10.03	$7.02	$4.59	$2.40	2.5%	-2.4%	-1.4%	-10.5%
1998	$10.29	$6.69	$4.21	$2.37	2.6%	-4.7%	-8.2%	-1.2%
1999	$10.23	$6.34	$4.03	$2.66	-0.6%	-5.2%	-4.4%	12.3%
2000	$11.10	$6.43	$5.78	$3.97	8.4%	1.4%	43.4%	49.4%
2001	$11.84	$7.46	$6.57	$3.09	6.7%	16.0%	13.8%	-22.2%
2002	$10.83	$6.97	$4.83	$3.51	-8.6%	-6.5%	-26.6%	13.4%
2003	$12.40	$10.17	$7.30	$6.20	14.5%	45.8%	51.3%	76.6%
2004	$13.65	$10.98	$9.05	$6.70	10.1%	8.0%	23.9%	8.1%
2005	$15.79	$12.70	$11.36	$9.61	15.6%	15.6%	25.5%	43.5%
2006	$17.10	$13.20	$10.56	$7.30	8.3%	4.0%	-7.0%	-24.0%
2007	$15.20	$11.92	$9.31	$7.77	-11.1%	-9.7%	-11.8%	6.4%
2008	$15.55	$12.23	$9.58	$8.02	2.3%	2.6%	2.9%	3.2%
2009	$15.34	$11.96	$9.28	$7.69	-1.4%	-2.2%	-3.2%	-4.1%
2010	$15.47	$12.05	$9.32	$7.72	0.9%	0.7%	0.5%	0.3%
2011	$15.81	$12.34	$9.58	$7.95	2.2%	2.4%	2.7%	3.0%
2012	$16.43	$12.91	$10.11	$8.46	3.9%	4.6%	5.5%	6.4%
2013	$16.96	$13.39	$10.56	$8.88	3.3%	3.8%	4.4%	5.0%
2014	$17.33	$13.71	$10.84	$9.14	2.2%	2.4%	2.7%	2.9%
2015	$17.71	$14.04	$11.13	$9.41	2.2%	2.4%	2.7%	2.9%
2016	$18.09	$14.38	$11.43	$9.68	2.2%	2.4%	2.7%	2.9%
2017	$18.48	$14.72	$11.73	$9.96	2.1%	2.4%	2.6%	2.9%
2018	$18.88	$15.07	$12.04	$10.25	2.2%	2.4%	2.6%	2.9%

Note: Beginning in 2000, delivered natural gas prices for the electric sector are estimated.

DELIVERED PROPANE PRICES FORECAST

Cents/Gallon (Selkirk)

Winter

Year	Current $	Percent Change
1989	--	
1990	--	
1991	45.3	
1992	39.1	-13.8%
1993	40.2	3.0%
1994	40.8	1.3%
1995	42.6	4.4%
1996	59.8	40.4%
1997	51.8	-13.3%
1998	37.1	-28.4%
1999	40.7	9.6%
2000	72.3	77.8%
2001	61.7	-14.7%
2002	50.3	-18.4%
2003	74.3	47.6%
2004	84.5	13.7%
2005	99.4	17.7%
2006	104.9	5.5%
2007	137.8	31.3%
2008	178.8	29.8%
2009	169.6	-5.1%
2010	152.0	-10.4%
2011	154.5	1.6%
2012	160.6	4.0%
2013	167.0	3.9%
2014	173.4	3.9%
2015	180.0	3.8%
2016	186.7	3.7%
2017	196.7	5.3%
2018	207.1	5.3%

Annual

Year	Current $	Percent Change
1989	--	
1990	--	
1991	42.6	
1992	40.9	-4.1%
1993	40.8	-0.1%
1994	40.6	-0.6%
1995	41.9	3.3%
1996	56.9	35.7%
1997	48.9	-14.0%
1998	36.5	-25.3%
1999	44.2	21.0%
2000	69.1	56.3%
2001	62.3	-9.9%
2002	52.3	-15.9%
2003	74.0	41.3%
2004	95.7	29.4%
2005	100.5	5.0%
2006	109.8	9.3%
2007	137.5	25.2%
2008	176.3	28.3%
2009	168.0	-4.7%
2010	155.9	-7.1%
2011	158.4	1.6%
2012	164.8	4.0%
2013	171.3	3.9%
2014	178.0	3.9%
2015	184.8	3.8%
2016	191.7	3.7%
2017	202.0	5.4%
2018	212.7	5.3%

Summer

Year	Current $	Percent Change
1989	--	
1990	--	
1991	40.7	
1992	42.1	3.6%
1993	41.3	-2.1%
1994	40.5	-1.9%
1995	41.5	2.6%
1996	54.9	32.2%
1997	46.9	-14.6%
1998	36.1	-22.9%
1999	46.7	29.3%
2000	66.7	43.0%
2001	55.0	-17.6%
2002	52.5	-4.5%
2003	64.4	22.6%
2004	85.8	33.2%
2005	101.3	18.0%
2006	113.3	11.9%
2007	137.2	21.1%
2008	174.5	27.1%
2009	166.8	-4.4%
2010	158.8	-4.8%
2011	161.3	1.6%
2012	167.8	4.0%
2013	174.5	4.0%
2014	181.2	3.9%
2015	188.2	3.8%
2016	195.3	3.8%
2017	205.8	5.4%
2018	216.7	5.3%

HENRY HUB NATURAL GAS PRICE FORECAST

$/MMBtu

Year	Current $			Percent Change		
	Annual	Summer	Winter	Annual	Summer	Winter
1989	$1.70	$1.61	$1.82			
1990	$1.70	$1.48	$2.01	0.1%	-8.1%	10.2%
1991	$1.49	$1.39	$1.62	-12.5%	-5.7%	-19.4%
1992	$1.77	$1.87	$1.63	19.2%	34.4%	0.9%
1993	$2.12	$2.16	$2.07	19.7%	15.4%	26.7%
1994	$1.92	$1.78	$2.11	-9.5%	-17.4%	2.0%
1995	$1.69	$1.61	$1.79	-12.2%	-9.7%	-15.1%
1996	$2.76	$2.31	$3.39	63.4%	43.3%	88.7%
1997	$2.53	$2.40	$2.70	-8.4%	4.0%	-20.3%
1998	$2.08	$2.11	$2.05	-17.5%	-12.1%	-24.1%
1999	$2.27	$2.41	$2.06	8.7%	14.3%	0.7%
2000	$4.23	$4.19	$4.28	86.6%	73.9%	107.2%
2001	$4.07	$3.44	$4.96	-3.7%	-18.0%	15.9%
2002	$3.33	$3.40	$3.23	-18.2%	-1.0%	-34.9%
2003	$5.63	$5.17	$6.26	68.9%	51.9%	94.0%
2004	$5.84	$5.83	$5.86	3.9%	12.8%	-6.4%
2005	$8.81	$8.97	$8.59	50.8%	53.7%	46.6%
2006	$6.76	$6.21	$7.54	-23.3%	-30.8%	-12.3%
2007	$6.95	$6.82	$7.12	2.7%	9.9%	-5.5%
2008	$7.17	$6.92	$7.52	3.2%	1.5%	5.5%
2009	$6.83	$6.74	$6.95	-4.8%	-2.6%	-7.6%
2010	$6.84	$6.38	$7.48	0.1%	-5.4%	7.6%
2011	$7.06	$6.59	$7.72	3.2%	3.2%	3.2%
2012	$7.55	$7.05	$8.26	7.0%	7.0%	7.0%
2013	$7.97	$7.44	$8.71	5.5%	5.5%	5.5%
2014	$8.21	$7.67	$8.98	3.1%	3.1%	3.1%
2015	$8.47	$7.90	$9.26	3.1%	3.1%	3.1%
2016	$8.73	$8.15	$9.55	3.1%	3.1%	3.1%
2017	$9.00	$8.40	$9.84	3.1%	3.1%	3.1%
2018	$9.27	$8.65	$10.14	3.1%	3.1%	3.1%

TX-LA ONSHORE WELLHEAD NATURAL GAS PRICE FORECAST
$/MMBtu

	Current $			Percent Change		
Year	Annual	Summer	Winter	Annual	Summer	Winter
1989	$1.63	$1.55	$1.76			
1990	$1.61	$1.42	$1.87	-1.6%	-8.1%	6.5%
1991	$1.39	$1.30	$1.52	-13.3%	-8.2%	-18.8%
1992	$1.65	$1.74	$1.52	18.4%	33.9%	-0.2%
1993	$2.00	$2.04	$1.94	21.2%	17.1%	27.9%
1994	$1.78	$1.68	$1.93	-11.0%	-17.9%	-0.7%
1995	$1.55	$1.49	$1.65	-12.7%	-11.4%	-14.3%
1996	$2.45	$2.13	$2.90	57.6%	43.1%	75.8%
1997	$2.39	$2.27	$2.56	-2.4%	6.9%	-11.9%
1998	$1.98	$2.01	$1.94	-17.0%	-11.4%	-24.0%
1999	$2.15	$2.30	$1.94	8.3%	14.1%	0.0%
2000	$4.09	$4.05	$4.13	90.1%	76.5%	112.8%
2001	$3.93	$3.32	$4.78	-3.8%	-18.0%	15.6%
2002	$3.21	$3.28	$3.10	-18.4%	-1.1%	-35.2%
2003	$5.39	$5.00	$5.92	68.0%	52.4%	91.2%
2004	$5.72	$5.66	$5.80	6.1%	13.1%	-2.1%
2005	$8.25	$8.56	$7.82	44.4%	51.3%	34.9%
2006	$6.48	$6.05	$7.10	-21.4%	-29.4%	-9.2%
2007	$6.69	$6.63	$6.78	3.2%	9.6%	-4.5%
2008	$6.90	$6.65	$7.25	3.2%	0.4%	7.0%
2009	$6.56	$6.47	$6.68	-4.9%	-2.7%	-7.8%
2010	$6.57	$6.11	$7.21	0.1%	-5.6%	7.9%
2011	$6.79	$6.32	$7.45	3.4%	3.4%	3.4%
2012	$7.28	$6.78	$7.99	7.3%	7.3%	7.3%
2013	$7.82	$7.68	$8.11	7.4%	13.3%	1.5%
2014	$8.07	$7.93	$8.36	3.1%	3.2%	3.1%
2015	$8.32	$8.18	$8.61	3.1%	3.2%	3.1%
2016	$8.58	$8.44	$8.88	3.1%	3.1%	3.0%
2017	$8.84	$8.70	$9.14	3.1%	3.1%	3.0%
2018	$9.12	$8.97	$9.42	3.1%	3.1%	3.0%

LA GULF COAST ONSHORE GAS PRICE FORECAST

$/MMBtu

Year	Current $			Percent Change		
	Annual	Summer	Winter	Annual	Summer	Winter
1989	$1.69	$1.60	$1.81			
1990	$1.69	$1.48	$1.98	0.0%	-7.5%	9.4%
1991	$1.48	$1.37	$1.62	-12.4%	-7.1%	-17.9%
1992	$1.74	$1.86	$1.57	17.8%	35.8%	-3.6%
1993	$2.10	$2.16	$2.02	20.8%	15.9%	29.0%
1994	$1.89	$1.77	$2.06	-10.2%	-18.2%	1.8%
1995	$1.60	$1.54	$1.69	-15.1%	-13.0%	-17.6%
1996	$2.62	$2.18	$3.25	63.7%	41.5%	91.9%
1997	$2.45	$2.31	$2.65	-6.6%	6.2%	-18.6%
1998	$2.04	$2.05	$2.02	-16.8%	-11.1%	-23.7%
1999	$2.21	$2.34	$2.02	8.3%	14.1%	0.0%
2000	$4.16	$4.12	$4.22	88.6%	75.8%	109.3%
2001	$3.98	$3.37	$4.85	-4.3%	-18.3%	14.8%
2002	$3.26	$3.33	$3.16	-18.2%	-1.2%	-34.8%
2003	$5.39	$5.04	$5.88	65.5%	51.5%	86.0%
2004	$5.69	$5.56	$5.86	5.5%	10.4%	-0.4%
2005	$8.63	$8.92	$8.23	51.8%	60.3%	40.4%
2006	$6.72	$6.26	$7.35	-22.2%	-29.8%	-10.7%
2007	$6.94	$6.79	$7.16	3.4%	8.4%	-2.6%
2008	$7.12	$6.87	$7.47	2.5%	1.2%	4.3%
2009	$6.78	$6.69	$6.90	-4.8%	-2.6%	-7.6%
2010	$6.79	$6.33	$7.43	0.1%	-5.4%	7.6%
2011	$7.01	$6.54	$7.67	3.3%	3.3%	3.3%
2012	$7.50	$7.00	$8.21	7.1%	7.1%	7.1%
2013	$7.84	$7.76	$7.83	4.5%	10.8%	-4.6%
2014	$8.09	$8.00	$8.08	3.1%	3.1%	3.1%
2015	$8.34	$8.25	$8.33	3.1%	3.2%	3.1%
2016	$8.60	$8.51	$8.59	3.1%	3.1%	3.1%
2017	$8.87	$8.77	$8.86	3.1%	3.1%	3.1%
2018	$9.14	$9.05	$9.13	3.1%	3.1%	3.1%

Boston City Gate Natural Gas Price
$/MMBtu

Year	Current $			Percent Change		
	Annual	Summer	Winter	Annual	Summer	Winter
1992	$2.28	$2.30	$2.26			
1993	$2.57	$2.53	$2.64	12.8%	10.1%	16.6%
1994	$2.44	$2.10	$2.92	-5.3%	-17.2%	10.7%
1995	$2.25	$1.89	$2.76	-7.5%	-9.8%	-5.3%
1996	$3.60	$2.60	$4.99	59.6%	37.5%	80.8%
1997	$2.94	$2.72	$3.25	-18.4%	4.4%	-35.0%
1998	$2.42	$2.37	$2.48	-17.7%	-12.7%	-23.6%
1999	$2.57	$2.64	$2.48	6.3%	11.2%	-0.2%
2000	$5.18	$4.50	$6.13	101.6%	70.7%	147.7%
2001	$4.42	$3.78	$5.32	-14.6%	-16.0%	-13.2%
2002	$3.52	$3.52	$3.52	-20.4%	-6.8%	-33.8%
2003	$6.35	$5.41	$7.01	80.2%	53.6%	98.9%
2004	$7.29	$6.35	$8.60	14.8%	17.4%	22.7%
2005	$9.85	$9.13	$10.87	35.3%	43.7%	26.5%
2006	$8.23	$6.88	$10.11	-16.5%	-24.6%	-7.0%
2007	$7.88	$7.43	$8.52	-4.2%	7.9%	-15.8%
2008	$8.37	$7.56	$9.50	6.2%	1.8%	11.5%
2009	$8.81	$8.72	$8.93	5.3%	15.4%	-6.0%
2010	$8.82	$8.36	$9.46	0.1%	-4.1%	5.9%
2011	$9.04	$8.57	$9.70	2.5%	2.5%	2.6%
2012	$9.53	$9.03	$10.24	5.5%	5.4%	5.6%
2013	$8.97	$8.07	$10.69	-5.9%	-10.6%	4.4%
2014	$9.24	$8.30	$10.96	2.9%	2.9%	2.5%
2015	$9.50	$8.54	$11.24	2.9%	2.9%	2.5%
2016	$9.78	$8.79	$11.53	2.9%	2.8%	2.5%
2017	$10.06	$9.04	$11.82	2.9%	2.8%	2.5%
2018	$10.35	$9.29	$12.12	2.9%	2.8%	2.5%

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

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QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON	A121

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	$25.59	$26.41	$24.85	$24.45	$26.34	$26.04	$24.94	$23.65	$24.09	$40.52	$30.37	$31.04	$50.27	$54.42	$45.82	$46.61	$78.98	$50.48	$41.14	$37.42
-1.8%, 13000 BTU	$25.06	$25.55	$23.49	$22.21	$22.51	$22.89	$23.59	$22.12	$23.07	$39.46	$29.38	$29.83	$48.89	$52.23	$43.41	$45.85	$77.43	$49.13	$40.29	$36.70
-2.3%, 13000 BTU	$22.40	$21.72	$21.48	$20.71	$21.26	$21.79	$22.54	$20.65	$22.05	$35.99	$27.51	$28.67	$47.91	$48.94	$39.80	$44.71	$75.10	$47.10	$39.00	$35.63
Central Appalachia																				
-.7%, 12500 BTU	$24.31	$26.02	$26.75	$24.86	$26.01	$25.45	$25.97	$24.50	$24.90	$47.09	$29.20	$34.27	$58.62	$61.97	$55.91	$46.46	$80.25	$57.87	$54.38	$54.87
-.7%, 13000 BTU	$26.08	$27.58	$28.31	$26.60	$25.80	$25.25	$25.77	$25.15	$26.42	$50.06	$31.07	$36.49	$62.42	$66.01	$59.56	$49.50	$85.52	$61.68	$57.99	$58.62
-1.0%, 12500 BTU	$21.94	$24.01	$24.22	$22.84	$24.41	$24.02	$24.24	$23.29	$23.45	$44.09	$27.25	$32.04	$55.03	$57.49	$50.71	$44.33	$76.94	$54.65	$50.03	$46.34
-1.5%, 12500 BTU	$21.54	$22.92	$22.70	$21.72	$22.73	$23.05	$23.33	$22.07	$21.72	$38.50	$24.19	$29.19	$49.92	$53.18	$45.49	$40.72	$59.26	$39.79	$39.91	$42.00
Ohio																				
-4%, 12500 BTU	$19.79	$21.50	$20.83	$18.38	$18.25	$18.34	$18.05	$18.41	$18.89	$26.44	$20.72	$23.01	$33.25	$35.88	$32.55	$39.19	$69.01	$42.54	$35.36	$32.34
Illinois Basin																				
-3%, 11000 BTU (IL)	$18.93	$21.68	$19.85	$16.96	$17.71	$18.10	$18.25	$17.44	$16.83	$24.63	$19.71	$19.61	$26.12	$27.54	$27.01	$27.01	$35.91	$32.47	$33.37	$33.43
-3%, 11000 BTU (KY)	$20.03	$22.78	$20.95	$18.10	$19.29	$20.25	$19.90	$18.81	$17.51	$29.93	$23.34	$22.09	$29.18	$29.82	$29.06	$28.91	$37.81	$34.28	$35.18	$35.27
Powder River Basin																				
-.33%, 8400 BTU	$3.58	$3.26	$4.34	$3.60	$3.09	$3.13	$3.35	$3.45	$3.43	$7.58	$4.74	$5.13	$5.23	$7.96	$10.17	$8.36	$12.91	$10.88	$10.08	$10.22
-.35%, 8800 BTU	$4.58	$4.64	$5.08	$4.68	$4.11	$4.29	$4.45	$4.42	$4.38	$9.34	$5.85	$6.21	$6.26	$10.09	$12.74	$9.85	$15.56	$12.30	$11.49	$12.09
Uinta Basin																				
-.5%, 11500 BTU	$19.79	$19.35	$13.64	$14.05	$13.58	$15.18	$15.09	$14.16	$13.35	$20.06	$16.95	$17.13	$26.82	$33.11	$36.76	$29.93	$38.15	$28.99	$25.54	$24.86
Foreign Coal																				
-.7%, 12000 BTU	$28.74	$26.45	$28.05	$34.31	$32.76	$31.71	$29.31	$26.35	$27.89	$35.37	$27.70	$33.43	$59.18	$50.12	$50.53	$62.03	$105.40	$65.52	$56.25	$52.13
-.8%, 11600 BTU						$29.61	$26.70	$24.09	$25.79	$32.94	$26.04	$31.41	$55.40	$46.90	$47.22	$57.85	$98.30	$61.13	$52.57	$48.81
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			$15.42	$12.55	$18.22	$19.39	$3.52	$1.71	$9.98	$12.73	$8.57	$13.03	$11.27	$17.50	$34.76	$44.90	$59.59	$48.09	$46.66	$39.99

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	**$35.40**	**$35.72**	**$32.91**	**$31.73**	**$33.55**	**$32.62**	**$30.91**	**$28.89**	**$28.79**	**$47.30**	**$34.85**	**$34.87**	**$54.91**	**$57.58**	**$46.99**	**$46.61**	**$77.70**	**$48.83**	**$39.03**	**$34.80**
-1.8%, 13000 BTU	**$34.68**	**$34.55**	**$31.11**	**$28.83**	**$28.68**	**$28.67**	**$29.23**	**$27.02**	**$27.58**	**$46.06**	**$33.71**	**$33.51**	**$53.40**	**$55.26**	**$44.52**	**$45.85**	**$76.17**	**$47.52**	**$38.22**	**$34.14**
-2.3%, 13000 BTU	**$31.00**	**$29.37**	**$28.44**	**$26.88**	**$27.08**	**$27.31**	**$27.93**	**$25.23**	**$26.37**	**$42.02**	**$31.56**	**$32.21**	**$52.32**	**$51.77**	**$40.82**	**$44.71**	**$73.88**	**$45.55**	**$37.01**	**$33.14**
Central Appalachia																				
-.7%, 12500 BTU	**$33.63**	**$35.19**	**$35.43**	**$32.27**	**$33.13**	**$31.89**	**$32.19**	**$29.92**	**$29.77**	**$54.97**	**$33.50**	**$38.51**	**$64.02**	**$65.56**	**$57.34**	**$46.46**	**$78.95**	**$55.98**	**$51.60**	**$51.04**
-.7%, 13000 BTU	**$36.08**	**$37.29**	**$37.49**	**$34.52**	**$32.86**	**$31.64**	**$31.93**	**$30.72**	**$31.59**	**$58.44**	**$35.65**	**$41.00**	**$68.17**	**$69.84**	**$61.09**	**$49.50**	**$84.14**	**$59.66**	**$55.02**	**$54.52**
-1.0%, 12500 BTU	**$30.36**	**$32.48**	**$32.07**	**$29.64**	**$31.10**	**$30.10**	**$30.04**	**$28.45**	**$28.03**	**$51.47**	**$31.27**	**$36.00**	**$60.10**	**$60.82**	**$52.00**	**$44.33**	**$75.69**	**$52.86**	**$47.47**	**$43.10**
-1.5%, 12500 BTU	**$29.80**	**$31.00**	**$30.06**	**$28.19**	**$28.96**	**$28.88**	**$28.91**	**$26.96**	**$25.96**	**$44.95**	**$27.76**	**$32.80**	**$54.53**	**$56.27**	**$46.65**	**$40.72**	**$58.30**	**$38.48**	**$37.87**	**$39.06**
Ohio																				
-4%, 12500 BTU	**$27.38**	**$29.08**	**$27.58**	**$23.85**	**$23.25**	**$22.98**	**$22.37**	**$22.49**	**$22.58**	**$30.86**	**$23.78**	**$25.86**	**$36.32**	**$37.96**	**$33.38**	**$39.19**	**$67.89**	**$41.15**	**$33.55**	**$30.08**
Illinois Basin																				
-3%, 11000 BTU (IL)	**$26.18**	**$29.31**	**$26.29**	**$22.02**	**$22.56**	**$22.68**	**$22.62**	**$21.30**	**$20.11**	**$28.75**	**$22.62**	**$22.04**	**$28.52**	**$29.14**	**$27.70**	**$27.01**	**$35.33**	**$31.40**	**$31.66**	**$31.10**
-3%, 11000 BTU (KY)	**$27.71**	**$30.80**	**$27.74**	**$23.49**	**$24.57**	**$25.37**	**$24.66**	**$22.98**	**$20.94**	**$34.93**	**$26.78**	**$24.82**	**$31.86**	**$31.54**	**$29.80**	**$28.91**	**$37.20**	**$33.15**	**$33.38**	**$32.81**
Powder River Basin																				
-.33%, 8400 BTU	**$4.95**	**$4.41**	**$5.74**	**$4.67**	**$3.93**	**$3.92**	**$4.15**	**$4.21**	**$4.09**	**$8.84**	**$5.44**	**$5.76**	**$5.71**	**$8.42**	**$10.43**	**$8.36**	**$12.70**	**$10.53**	**$9.56**	**$9.50**
-.35%, 8800 BTU	**$6.33**	**$6.27**	**$6.72**	**$6.07**	**$5.24**	**$5.37**	**$5.51**	**$5.40**	**$5.23**	**$10.90**	**$6.71**	**$6.98**	**$6.84**	**$10.67**	**$13.06**	**$9.85**	**$15.31**	**$11.89**	**$10.90**	**$11.24**
Uinta Basin																				
-.5%, 11500 BTU	**$27.38**	**$26.17**	**$18.06**	**$18.24**	**$17.29**	**$19.01**	**$18.70**	**$17.30**	**$15.96**	**$23.42**	**$19.45**	**$19.24**	**$29.29**	**$35.02**	**$37.70**	**$29.93**	**$37.54**	**$28.04**	**$24.23**	**$23.12**
Foreign Coal: Colombia																				
-.7%, 12000 BTU	**$39.76**	**$35.77**	**$37.15**	**$44.53**	**$41.73**	**$39.73**	**$36.32**	**$32.19**	**$33.34**	**$41.29**	**$31.78**	**$37.56**	**$64.64**	**$53.02**	**$51.82**	**$62.03**	**$103.69**	**$63.38**	**$53.37**	**$48.48**
-.8%, 11600 BTU						**$37.10**	**$33.09**	**$29.42**	**$30.83**	**$38.45**	**$29.87**	**$35.29**	**$60.50**	**$49.62**	**$48.43**	**$57.85**	**$96.71**	**$59.13**	**$49.88**	**$45.39**
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			**$20.42**	**$16.29**	**$23.21**	**$24.30**	**$4.36**	**$2.09**	**$11.93**	**$14.86**	**$9.83**	**$14.64**	**$12.31**	**$18.52**	**$35.65**	**$44.90**	**$58.62**	**$46.51**	**$44.27**	**$37.19**
IMPLICIT PRICE DEFLATOR (GDP)	86.40	88.39	90.27	92.10	93.85	95.41	96.47	97.86	100.00	102.40	104.19	106.40	109.45	112.99	116.56	119.54	121.51	123.59	126.00	128.53
% Change	2.77%	2.30%	2.12%	2.04%	1.89%	1.67%	1.11%	1.44%	2.18%	2.40%	1.74%	2.12%	2.87%	3.23%	3.16%	2.56%	1.65%	1.71%	1.95%	2.01%

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	1995	1996		1996	1996	1997		1997		1998		1998		1999				2000	
Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Northern Appalachia																				
-1.6%, 13000 BTU	$24.73	$24.68	$26.27	$24.93	$26.76	$27.41	$26.76	$25.67	$25.77	$25.94	$25.72	$24.63	$24.63	$24.78	$24.43	$23.54	$23.29	$23.34	$22.90	$22.95
-1.8%, 13000 BTU	$22.15	$22.10	$23.29	$22.10	$22.35	$22.30	$22.40	$22.30	$23.05	$23.79	$23.79	$23.29	$23.84	$23.44	$22.80	$21.66	$21.41	$22.60	$22.03	$22.00
-2.3%, 13000 BTU	$20.96	$20.87	$21.81	$20.91	$21.21	$21.11	$21.21	$21.16	$22.01	$22.80	$22.80	$22.25	$22.80	$22.30	$21.51	$19.73	$19.92	$21.46	$21.11	$20.96
Central Appalachia																				
-.7%, 12500 BTU	$24.95	$24.70	$25.71	$24.50	$26.86	$26.97	$27.17	$24.55	$24.50	$25.60	$25.64	$25.27	$26.28	$26.71	$25.91	$24.14	$23.89	$24.04	$23.54	$23.39
-.7%, 13000 BTU	$26.49	$26.23	$25.50	$24.30	$26.65	$26.75	$26.95	$24.35	$24.30	$25.40	$25.43	$25.07	$26.07	$26.50	$25.70	$23.95	$25.46	$25.50	$24.96	$24.78
-1.0%, 12500 BTU	$22.92	$22.81	$24.11	$23.54	$24.90	$25.10	$25.21	$23.59	$23.33	$23.96	$24.06	$23.33	$24.48	$25.10	$24.32	$23.13	$22.92	$22.81	$22.34	$22.19
-1.5%, 12500 BTU	$21.61	$21.46	$22.50	$21.56	$23.44	$23.44	$23.54	$23.13	$22.40	$23.13	$23.18	$22.81	$23.33	$24.01	$23.13	$22.03	$21.82	$21.30	$20.73	$20.63
Ohio																				
-4%, 12500 BTU	$18.35	$18.25	$18.25	$18.20	$18.30	$18.25	$18.40	$18.30	$18.35	$18.30	$18.30	$18.10	$18.10	$17.70	$18.35	$18.00	$18.40	$18.90	$19.00	$18.25
Illinois Basin																				
-3%, 11000 BTU (IL)	$16.70	$ 16.85	$ 17.50	$ 17.35	$ 18.00	$ 18.00	$18.00	$18.00	$18.15	$18.25	$18.25	$17.95	$ 18.20	$ 18.60	$18.10	$17.50	$17.15	$17.00	$16.75	$16.70
-3%, 11000 BTU (KY)	$17.80	$ 18.10	$ 18.75	$ 18.50	$ 19.90	$ 20.00	$21.00	$20.05	$20.00	$19.95	$20.05	$19.35	$ 20.00	$ 20.20	$19.75	$19.00	$18.45	$18.05	$17.20	$16.95
Powder River Basin																				
-.33%, 8400 BTU	$3.40	$3.30	$3.20	$3.15	$3.00	$3.00	$3.00	$3.00	$3.20	$3.30	$3.62	$3.35	$3.15	$3.27	$3.38	$3.45	$3.47	$3.50	$3.40	$3.20
-.35%, 8800 BTU	$4.45	$4.40	$4.25	$4.20	$4.00	$4.00	$4.00	$4.05	$4.50	$4.60	$4.80	$4.45	$4.20	$4.34	$4.38	$4.45	$4.40	$4.45	$4.40	$4.20
Uinta Basin																				
-.5%, 11500 BTU	$14.20	$14.00	$13.50	$13.20	$13.60	$14.00	$14.40	$15.05	$15.65	$15.60	$15.25	$15.20	$ 15.10	$ 14.80	$14.65	$14.40	$14.10	$13.50	$12.75	$12.80
Foreign Coal																				
-.7%, 12000 BTU	$34.20	$34.50	$33.65	$32.15	$32.00	$33.25	$33.50	$32.40	$30.95	$30.00	$29.20	$29.00	$30.15	$28.90	$28.40	$28.00	$24.60	$24.40	$26.00	$27.25
-.8%, 11600 BTU							$31.54	$30.51	$28.69	$27.71	$26.61	$26.08	$27.99	$26.13	$25.63	$24.63	$23.34	$22.75	$24.13	$25.21
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$10.28	$11.79	$15.88	$17.24	$19.35	$20.41	$21.47	$21.02	$19.81	$15.27	$7.41	$3.93	$1.36	$1.36	$1.36	$1.36	$1.36	$2.75	$5.58	$5.73

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE SPOT
BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$35.74	$34.76	$34.75	$35.09	$35.54	$36.06	$36.54	$37.02	$37.53	$39.24	$39.84	$40.46	$41.09	$41.75	$42.41	$43.07	$43.72	$44.38	$45.08
-1.8%, 13000 BTU	$35.12	$34.22	$34.33	$34.68	$35.15	$35.67	$36.17	$36.67	$37.21	$38.89	$39.49	$40.11	$40.74	$41.39	$42.04	$42.70	$43.34	$43.99	$44.69
-2.3%, 13000 BTU	$34.18	$33.40	$33.68	$34.07	$34.56	$35.08	$35.61	$36.14	$36.73	$38.38	$38.97	$39.58	$40.20	$40.85	$41.49	$42.14	$42.77	$43.41	$44.10
Central Appalachia																			
-.7%, 12500 BTU	$54.93	$55.89	$56.32	$57.10	$58.07	$59.24	$60.63	$62.10	$63.62	$65.95	$68.34	$70.14	$71.93	$73.84	$75.83	$77.84	$79.91	$81.97	$84.09
-.7%, 13000 BTU	$58.64	$59.66	$60.12	$60.95	$61.98	$63.24	$64.71	$66.28	$67.91	$70.40	$72.96	$74.89	$76.81	$78.85	$80.99	$83.14	$85.36	$87.57	$89.84
-1.0%, 12500 BTU	$44.52	$42.80	$42.61	$42.98	$43.60	$44.39	$45.26	$46.09	$47.07	$48.58	$50.16	$51.25	$52.35	$53.50	$54.65	$55.82	$57.00	$58.19	$59.46
-1.5%, 12500 BTU	$41.26	$41.31	$41.48	$42.20	$42.99	$43.79	$44.66	$45.54	$46.53	$48.04	$49.63	$50.72	$51.83	$52.98	$54.14	$55.31	$56.50	$57.69	$58.96
Ohio																			
-4%, 12500 BTU	$31.04	$30.34	$30.61	$30.98	$31.44	$31.93	$32.42	$32.92	$33.47	$35.00	$35.55	$36.13	$36.71	$37.32	$37.92	$38.53	$39.13	$39.74	$40.38
Illinois Basin																			
-3%, 11000 BTU (IL)	$33.52	$33.62	$33.70	$33.91	$34.20	$34.53	$34.84	$35.19	$35.48	$35.87	$36.25	$36.63	$36.96	$37.33	$37.77	$38.23	$38.67	$39.11	$39.58
-3%, 11000 BTU (KY)	$35.37	$35.52	$35.66	$35.92	$36.27	$36.65	$37.02	$37.42	$37.78	$38.23	$38.66	$39.10	$39.50	$39.92	$40.44	$40.96	$41.47	$41.97	$42.51
Powder River Basin																			
-.33%, 8400 BTU	$10.01	$9.86	$9.75	$9.80	$9.89	$10.12	$10.35	$10.56	$10.81	$11.16	$11.52	$11.72	$11.90	$12.10	$12.26	$12.45	$12.63	$12.80	$13.01
-.35%, 8800 BTU	$12.01	$12.03	$12.03	$12.17	$12.37	$12.63	$12.91	$13.21	$13.59	$14.04	$14.49	$14.78	$15.06	$15.36	$15.63	$15.92	$16.22	$16.50	$16.84
Uinta Basin																			
-.5%, 11500 BTU	$24.00	$24.26	$24.59	$24.93	$25.31	$25.68	$26.05	$26.43	$26.85	$27.26	$27.67	$28.10	$28.53	$28.98	$29.43	$29.88	$30.33	$30.78	$31.26
Foreign Coal																			
-.7%, 12000 BTU	$49.89	$49.93	$50.47	$51.00	$51.55	$52.23	$52.93	$53.60	$54.27	$55.01	$55.80	$56.62	$57.49	$58.40	$59.38	$60.40	$61.44	$62.52	$63.57
-.8%, 11600 BTU	$46.84	$47.02	$47.62	$48.25	$48.91	$49.57	$50.27	$50.96	$51.69	$52.44	$53.20	$54.00	$54.84	$55.73	$56.67	$57.64	$58.63	$59.66	$60.67
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$37.26	$37.14	$37.52	$37.92	$38.35	$38.78	$39.25	$39.72	$40.21	$40.73	$41.28	$41.86	$42.48	$43.14	$43.85	$44.60	$45.37	$46.19	$46.97

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE SPOT
BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$32.59	$31.11	$30.51	$30.22	$30.02	$29.88	$29.71	$29.53	$29.39	$30.16	$30.07	$29.99	$29.90	$29.82	$29.73	$29.64	$29.54	$29.44	$29.37
-1.8%, 13000 BTU	$32.02	$30.62	$30.13	$29.86	$29.68	$29.56	$29.40	$29.25	$29.14	$29.90	$29.81	$29.73	$29.64	$29.56	$29.47	$29.38	$29.28	$29.19	$29.11
-2.3%, 13000 BTU	$31.17	$29.89	$29.57	$29.34	$29.19	$29.07	$28.95	$28.83	$28.76	$29.50	$29.42	$29.34	$29.25	$29.18	$29.09	$28.99	$28.90	$28.80	$28.73
Central Appalachia																			
-.7%, 12500 BTU	$50.09	$50.01	$49.45	$49.16	$49.04	$49.09	$49.29	$49.54	$49.82	$50.69	$51.58	$51.98	$52.34	$52.74	$53.16	$53.56	$53.99	$54.38	$54.78
-.7%, 13000 BTU	$53.48	$53.39	$52.78	$52.48	$52.35	$52.41	$52.61	$52.89	$53.18	$54.12	$55.07	$55.51	$55.89	$56.32	$56.77	$57.21	$57.67	$58.10	$58.53
-1.0%, 12500 BTU	$40.60	$38.30	$37.41	$37.01	$36.83	$36.79	$36.79	$36.78	$36.86	$37.34	$37.86	$37.98	$38.09	$38.21	$38.31	$38.41	$38.51	$38.60	$38.74
-1.5%, 12500 BTU	$37.63	$36.97	$36.42	$36.34	$36.31	$36.29	$36.30	$36.34	$36.44	$36.93	$37.46	$37.59	$37.71	$37.84	$37.95	$38.06	$38.17	$38.27	$38.41
Ohio																			
-4%, 12500 BTU	$28.30	$27.15	$26.87	$26.67	$26.55	$26.46	$26.36	$26.27	$26.21	$26.90	$26.84	$26.78	$26.71	$26.65	$26.58	$26.51	$26.44	$26.36	$26.31
Illinois Basin																			
-3%, 11000 BTU (IL)	$30.57	$30.08	$29.58	$29.20	$28.89	$28.61	$28.33	$28.07	$27.78	$27.58	$27.36	$27.15	$26.89	$26.66	$26.48	$26.30	$26.13	$25.95	$25.79
-3%, 11000 BTU (KY)	$32.26	$31.79	$31.30	$30.93	$30.63	$30.37	$30.10	$29.86	$29.58	$29.38	$29.18	$28.98	$28.74	$28.52	$28.35	$28.18	$28.02	$27.85	$27.70
Powder River Basin																			
-.33%, 8400 BTU	$9.13	$8.82	$8.56	$8.44	$8.36	$8.39	$8.41	$8.43	$8.47	$8.58	$8.69	$8.68	$8.66	$8.64	$8.60	$8.57	$8.54	$8.49	$8.48
-.35%, 8800 BTU	$10.96	$10.76	$10.56	$10.48	$10.45	$10.47	$10.49	$10.54	$10.64	$10.79	$10.93	$10.95	$10.96	$10.97	$10.96	$10.96	$10.96	$10.95	$10.97
Uinta Basin																			
-.5%, 11500 BTU	$21.89	$21.71	$21.59	$21.47	$21.38	$21.28	$21.17	$21.09	$21.03	$20.96	$20.89	$20.82	$20.76	$20.70	$20.63	$20.56	$20.49	$20.42	$20.36
Foreign Coal: Colombia																			
-.7%, 12000 BTU	$45.49	$44.69	$44.31	$43.92	$43.54	$43.28	$43.03	$42.77	$42.50	$42.29	$42.12	$41.96	$41.83	$41.72	$41.63	$41.56	$41.51	$41.48	$41.41
-.8%, 11600 BTU	$42.71	$42.08	$41.80	$41.55	$41.31	$41.08	$40.87	$40.66	$40.48	$40.31	$40.16	$40.02	$39.91	$39.81	$39.73	$39.66	$39.61	$39.58	$39.52
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$33.98	$33.24	$32.93	$32.65	$32.39	$32.14	$31.91	$31.69	$31.49	$31.31	$31.16	$31.02	$30.91	$30.81	$30.74	$30.69	$30.66	$30.64	$30.60
IMPLICIT PRICE DEFLATOR (GDP)	131.09	133.58	136.17	138.84	141.54	144.25	147.05	149.83	152.66	155.51	158.37	161.30	164.29	167.36	170.52	173.73	176.94	180.18	183.49
% Change	1.99%	1.90%	1.93%	1.96%	1.95%	1.91%	1.94%	1.89%	1.89%	1.87%	1.84%	1.85%	1.85%	1.87%	1.89%	1.88%	1.85%	1.83%	1.84%

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

QUARTERLY SPOT PRICES

BASE CASE

	2001						2002				2003				2004				2005			
Year: / Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia																						
-1.6%, 13000 BTU	$24.38	$26.12	$32.86	$42.38	$43.91	$42.92	$35.34	$29.34	$29.09	$27.70	$28.20	$30.88	$31.57	$33.50	$41.24	$45.53	$52.70	$61.62	$56.60	$54.24	$53.91	$52.95
-1.8%, 13000 BTU	$23.59	$24.65	$31.91	$41.26	$42.81	$41.85	$34.32	$28.36	$28.09	$26.73	$27.01	$29.66	$30.41	$32.23	$40.04	$44.46	$51.30	$59.78	$55.15	$52.33	$51.52	$49.91
-2.3%, 13000 BTU	$22.55	$23.59	$29.39	$37.07	$39.40	$38.11	$31.57	$26.61	$26.66	$25.18	$25.82	$28.50	$29.34	$31.03	$39.12	$43.84	$50.32	$58.33	$52.98	$49.48	$47.94	$45.35
Central Appalachia																						
-.7%, 12500 BTU	$24.65	$28.02	$46.72	$51.11	$49.19	$41.33	$30.14	$27.67	$29.23	$29.74	$32.36	$34.02	$33.87	$36.84	$49.62	$56.75	$62.95	$65.15	$62.35	$63.07	$60.38	$62.08
-.7%, 13000 BTU	$26.17	$29.77	$49.66	$54.33	$52.31	$43.93	$32.07	$29.43	$31.12	$31.65	$34.44	$36.21	$36.07	$39.24	$52.84	$60.43	$67.05	$69.37	$66.41	$67.18	$64.33	$66.12
-1.0%, 12500 BTU	$22.92	$26.35	$43.07	$48.65	$45.89	$38.75	$28.18	$25.94	$27.24	$27.66	$29.43	$31.77	$31.93	$35.05	$47.99	$54.08	$58.30	$59.75	$57.71	$59.20	$56.23	$56.81
-1.5%, 12500 BTU	$21.04	$24.48	$34.69	$43.65	$41.15	$34.53	$24.22	$22.86	$24.53	$25.16	$26.93	$28.85	$28.96	$32.03	$44.34	$49.69	$53.05	$52.61	$53.50	$54.86	$52.78	$51.59
Ohio																						
-4%, 12500 BTU	$18.75	$19.55	$23.95	$26.85	$27.85	$27.10	$22.34	$20.15	$20.45	$19.95	$21.40	$22.95	$23.35	$24.35	$28.09	$28.78	$35.38	$40.77	$36.73	$35.18	$35.75	$35.85
Illinois Basin																						
-3%, 11000 BTU (IL)	$16.80	$17.05	$22.05	$25.35	$25.65	$25.45	$21.90	$19.80	$18.50	$18.65	$18.80	$19.55	$19.60	$20.50	$22.55	$25.07	$26.80	$30.05	$27.32	$27.22	$27.75	$27.88
-3%, 11000 BTU (KY)	$17.45	$18.45	$24.30	$31.45	$32.10	$31.85	$27.80	$22.60	$21.50	$21.45	$21.45	$21.95	$22.10	$22.85	$24.95	$28.05	$30.50	$33.20	$30.03	$29.25	$29.83	$30.15
Powder River Basin																						
-.33%, 8400 BTU	$3.40	$3.70	$6.25	$10.65	$7.05	$6.35	$4.65	$4.70	$4.65	$4.95	$5.00	$4.80	$5.25	$5.45	$5.55	$5.43	$5.00	$4.93	$5.18	$6.35	$7.72	$12.57
-.35%, 8800 BTU	$4.35	$4.55	$7.90	$12.75	$8.70	$8.00	$5.85	$5.75	$5.75	$6.05	$6.00	$5.90	$6.30	$6.65	$6.58	$6.43	$6.02	$6.02	$6.33	$7.98	$10.03	$16.00
Uinta Basin																						
-.5%, 11500 BTU	$13.30	$14.55	$19.05	$19.85	$20.55	$20.80	$18.40	$16.30	$16.45	$16.65	$16.15	$16.90	$17.15	$18.30	$22.42	$25.95	$29.42	$29.50	$28.98	$31.12	$34.82	$37.50
Foreign Coal																						
-.7%, 12000 BTU	$27.85	$30.45	$35.10	$36.90	$36.85	$32.62	$29.81	$27.54	$25.06	$28.38	$28.55	$28.04	$35.00	$42.12	$46.23	$54.39	$68.50	$67.62	$57.64	$49.06	$51.92	$41.84
-.8%, 11600 BTU	$25.63	$28.20	$32.60	$34.32	$34.31	$30.52	$27.99	$25.95	$23.57	$26.63	$26.83	$26.40	$32.86	$39.55	$43.28	$50.97	$64.08	$63.25	$53.92	$45.94	$48.57	$39.17
Petroleum Coke																						
-6%/30 HGI, 14000 BTU	$8.83	$19.78	$18.11	$14.62	$9.95	$8.24	$7.44	$5.79	$7.97	$13.08	$20.35	$14.53	$8.52	$8.71	$6.60	$6.46	$14.71	$20.46	$22.76	$13.25	$12.02	$21.98

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

QUARTERLY SPOT PRICE
BASE CASE

Year:	2006				2007				2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia																				
-1.6%, 13000 BTU	$49.63	$46.60	$44.14	$42.90	$44.00	$44.75	$46.60	$51.10	$73.95	$88.05	$82.50	$71.42	$58.77	$49.90	$48.48	$44.78	$42.93	$41.18	$41.03	$39.42
-1.8%, 13000 BTU	$46.48	$43.85	$41.92	$41.40	$43.09	$44.02	$45.83	$50.46	$72.73	$86.53	$80.85	$69.60	$57.15	$48.43	$47.20	$43.74	$42.01	$40.22	$40.24	$38.68
-2.3%, 13000 BTU	$41.76	$39.72	$38.58	$39.14	$41.73	$42.93	$44.67	$49.50	$70.90	$84.25	$78.37	$66.88	$54.73	$46.22	$45.27	$42.17	$40.63	$38.77	$39.05	$37.57
Central Appalachia																				
-.7%, 12500 BTU	$61.21	$59.39	$54.23	$48.82	$41.92	$44.73	$45.65	$53.55	$74.38	$89.33	$85.03	$72.27	$61.70	$57.33	$57.10	$55.35	$54.95	$54.08	$54.77	$53.73
-.7%, 13000 BTU	$65.20	$63.26	$57.79	$52.01	$44.66	$47.65	$48.65	$57.06	$79.26	$95.18	$90.63	$77.01	$65.76	$61.10	$60.87	$59.00	$58.58	$57.65	$58.40	$57.28
-1.0%, 12500 BTU	$55.10	$51.81	$49.69	$46.23	$39.55	$42.53	$43.65	$51.60	$71.43	$85.48	$81.50	$69.35	$58.85	$54.25	$53.77	$51.75	$51.05	$49.88	$50.27	$48.93
-1.5%, 12500 BTU	$48.97	$46.25	$44.09	$42.62	$35.52	$39.22	$40.17	$47.98	$63.05	$67.21	$59.57	$47.20	$41.20	$38.95	$39.65	$39.35	$39.67	$39.35	$40.38	$40.25
Ohio																				
-4%, 12500 BTU	$34.63	$32.63	$30.67	$32.24	$35.45	$37.43	$38.63	$45.23	$65.86	$78.04	$71.70	$60.44	$49.28	$41.73	$40.95	$38.21	$36.86	$35.13	$35.42	$34.05
Illinois Basin																				
-3%, 11000 BTU (IL)	$27.27	$26.53	$26.63	$27.60	$26.85	$26.53	$26.93	$27.73	$32.13	$39.42	$38.23	$33.85	$32.07	$32.27	$32.83	$32.70	$32.98	$32.98	$33.93	$33.58
-3%, 11000 BTU (KY)	$29.37	$28.57	$28.72	$29.58	$28.77	$28.52	$28.77	$29.60	$34.05	$41.40	$40.07	$35.72	$33.88	$34.13	$34.60	$34.48	$34.80	$34.85	$35.70	$35.37
Powder River Basin																				
-.33%, 8400 BTU	$14.20	$10.63	$8.20	$7.63	$7.18	$7.48	$8.92	$9.85	$11.97	$13.85	$13.15	$12.68	$12.22	$11.50	$10.48	$9.33	$9.83	$9.70	$10.50	$10.28
-.35%, 8800 BTU	$17.68	$13.62	$10.18	$9.47	$8.80	$8.93	$10.47	$11.20	$14.42	$17.25	$15.97	$14.62	$13.65	$12.92	$11.82	$10.80	$11.27	$11.12	$11.83	$11.75
Uinta Basin																				
-.5%, 11500 BTU	$38.45	$37.62	$35.83	$35.13	$33.75	$32.50	$27.02	$26.43	$34.83	$42.40	$39.70	$35.68	$32.52	$29.07	$27.90	$26.47	$25.80	$25.40	$25.63	$25.32
Foreign Coal																				
-.7%, 12000 BTU	$48.83	$52.74	$50.93	$49.61	$51.13	$52.48	$59.37	$85.13	$111.06	$123.68	$105.18	$81.68	$70.69	$66.43	$63.52	$61.45	$59.55	$55.20	$56.82	$53.44
-.8%, 11600 BTU	$45.68	$49.24	$47.65	$46.32	$47.70	$48.95	$55.37	$79.38	$103.60	$115.38	$98.07	$76.17	$65.93	$61.96	$59.27	$57.35	$55.62	$51.57	$53.12	$49.98
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$24.99	$36.75	$39.32	$37.98	$44.03	$47.68	$44.98	$42.90	$55.19	$70.38	$60.30	$52.48	$49.98	$47.62	$47.55	$47.20	$46.93	$46.63	$47.30	$45.78

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

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ANNUAL AVERAGE CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$72.15	$49.33	$40.12	$37.51	$36.31	$35.86	$36.05	$36.46	$36.96	$37.47	$37.97	$38.68	$39.64
-1.8%, 13000 BTU	$70.51	$48.28	$39.38	$36.83	$35.73	$35.36	$35.62	$36.05	$36.56	$37.08	$37.60	$38.34	$39.30
-2.3%, 13000 BTU	$68.06	$46.70	$38.27	$35.82	$34.85	$34.61	$34.98	$35.43	$35.95	$36.50	$37.05	$37.81	$38.78
Central Appalachia													
-.7%, 12500 BTU	$73.85	$57.43	$55.24	$56.71	$57.15	$57.92	$58.58	$59.51	$60.65	$61.98	$63.46	$65.14	$67.14
-.7%, 13000 BTU	$78.72	$61.23	$58.93	$60.57	$61.01	$61.83	$62.53	$63.53	$64.74	$66.17	$67.74	$69.54	$71.67
-1.0%, 12500 BTU	$69.14	$52.38	$49.31	$46.50	$44.94	$44.05	$44.19	$44.73	$45.47	$46.31	$47.21	$48.24	$49.53
-1.5%, 12500 BTU	$55.50	$40.86	$41.23	$42.89	$42.56	$42.76	$43.23	$44.01	$44.84	$45.70	$46.62	$47.68	$48.98
Ohio													
-4%, 12500 BTU	$61.80	$42.50	$34.64	$32.52	$31.66	$31.45	$31.80	$32.23	$32.72	$33.23	$33.75	$34.46	$35.36
Illinois Basin													
-3%, 11000 BTU (IL)	$34.94	$33.31	$34.42	$34.50	$34.59	$34.70	$34.87	$35.13	$35.45	$35.79	$36.12	$36.46	$36.81
-3%, 11000 BTU (KY)	$36.83	$35.13	$36.30	$36.41	$36.53	$36.70	$36.92	$37.25	$37.62	$38.01	$38.40	$38.81	$39.22
Powder River Basin													
-.33%, 8400 BTU	$12.69	$10.74	$10.42	$10.39	$10.21	$10.11	$10.08	$10.18	$10.35	$10.58	$10.81	$11.07	$11.38
-.35%, 8800 BTU	$14.65	$12.46	$12.13	$12.42	$12.38	$12.41	$12.49	$12.68	$12.92	$13.21	$13.52	$13.88	$14.30
Uinta Basin													
-.5%, 11500 BTU	$33.60	$27.60	$25.81	$25.21	$24.91	$25.22	$25.57	$25.94	$26.32	$26.70	$27.10	$27.51	$27.94
Foreign Coal													
-.7%, 12000 BTU	$81.21	$60.35	$55.43	$52.54	$51.50	$51.80	$52.36	$52.93	$53.57	$54.27	$54.98	$55.68	$56.42
-.8%, 11600 BTU	$75.81	$56.44	$51.87	$49.29	$48.44	$48.85	$49.49	$50.15	$50.84	$51.54	$52.26	$53.00	$53.76
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$53.71	$47.54	$44.16	$39.76	$38.38	$38.52	$38.92	$39.36	$39.80	$40.27	$40.75	$41.25	$41.78

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE CONTRACT PRICES - REAL 2007 DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$70.98	$47.71	$38.07	$34.88	$33.11	$32.09	$31.65	$31.40	$31.21	$31.05	$30.87	$30.87	$31.04
-1.8%, 13000 BTU	$69.37	$46.69	$37.37	$34.26	$32.58	$31.64	$31.27	$31.04	$30.87	$30.73	$30.57	$30.59	$30.77
-2.3%, 13000 BTU	$66.95	$45.17	$36.31	$33.31	$31.78	$30.98	$30.71	$30.51	$30.37	$30.24	$30.12	$30.17	$30.37
Central Appalachia													
-.7%, 12500 BTU	$72.65	$55.55	$52.41	$52.75	$52.11	$51.83	$51.43	$51.24	$51.22	$51.37	$51.59	$51.98	$52.57
-.7%, 13000 BTU	$77.44	$59.23	$55.91	$56.33	$55.63	$55.33	$54.89	$54.70	$54.68	$54.83	$55.07	$55.48	$56.12
-1.0%, 12500 BTU	$68.02	$50.66	$46.78	$43.25	$40.98	$39.42	$38.79	$38.51	$38.40	$38.38	$38.38	$38.49	$38.78
-1.5%, 12500 BTU	$54.60	$39.52	$39.11	$39.89	$38.81	$38.27	$37.96	$37.90	$37.87	$37.87	$37.90	$38.04	$38.35
Ohio													
-4%, 12500 BTU	$60.80	$41.11	$32.87	$30.24	$28.87	$28.15	$27.92	$27.75	$27.63	$27.53	$27.43	$27.49	$27.69
Illinois Basin													
-3%, 11000 BTU (IL)	$34.37	$32.21	$32.66	$32.09	$31.54	$31.06	$30.61	$30.25	$29.94	$29.66	$29.36	$29.09	$28.83
-3%, 11000 BTU (KY)	$36.24	$33.98	$34.44	$33.86	$33.31	$32.84	$32.41	$32.07	$31.77	$31.50	$31.22	$30.96	$30.71
Powder River Basin													
-.33%, 8400 BTU	$12.48	$10.39	$9.88	$9.66	$9.31	$9.04	$8.85	$8.76	$8.74	$8.77	$8.79	$8.83	$8.91
-.35%, 8800 BTU	$14.41	$12.06	$11.51	$11.55	$11.29	$11.11	$10.97	$10.92	$10.91	$10.94	$10.99	$11.07	$11.20
Uinta Basin													
-.5%, 11500 BTU	$33.05	$26.70	$24.48	$23.44	$22.72	$22.57	$22.45	$22.34	$22.23	$22.13	$22.03	$21.95	$21.88
Foreign Coal: Colombia													
-.7%, 12000 BTU	$79.89	$58.38	$52.59	$48.87	$46.96	$46.36	$45.96	$45.58	$45.24	$44.98	$44.70	$44.43	$44.18
-.8%, 11600 BTU	$74.58	$54.59	$49.22	$45.84	$44.17	$43.71	$43.44	$43.18	$42.94	$42.71	$42.48	$42.28	$42.09
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$52.84	$45.98	$41.89	$36.98	$35.00	$34.47	$34.17	$33.89	$33.62	$33.37	$33.13	$32.91	$32.72

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

QUARTERLY CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$72.06	$78.83	$72.78	$64.93	$56.49	$48.00	$47.43	$45.39	$41.81	$40.00	$39.81	$38.87
-1.8%, 13000 BTU	$70.47	$77.05	$71.10	$63.42	$55.21	$46.96	$46.44	$44.49	$41.01	$39.25	$39.09	$38.18
-2.3%, 13000 BTU	$68.09	$74.39	$68.59	$61.15	$53.29	$45.39	$44.97	$43.14	$39.80	$38.13	$38.01	$37.15
Central Appalachia												
-.7%, 12500 BTU	$75.06	$79.18	$75.47	$65.68	$58.53	$57.43	$57.25	$56.50	$55.80	$55.29	$54.85	$55.00
-.7%, 13000 BTU	$80.00	$84.40	$80.45	$70.01	$62.40	$61.23	$61.04	$60.25	$59.52	$58.99	$58.53	$58.69
-1.0%, 12500 BTU	$70.81	$74.35	$70.50	$60.90	$53.88	$52.52	$52.05	$51.07	$50.18	$49.46	$48.85	$48.75
-1.5%, 12500 BTU	$60.95	$61.57	$53.60	$45.87	$40.65	$40.73	$41.00	$41.06	$41.07	$41.16	$41.28	$41.40
Ohio												
-4%, 12500 BTU	$62.05	$67.63	$62.17	$55.36	$48.26	$41.22	$40.94	$39.57	$36.78	$35.50	$35.66	$35.12
Illinois Basin												
-3%, 11000 BTU (IL)	$34.05	$36.49	$35.95	$33.26	$33.16	$33.27	$33.36	$33.43	$33.45	$33.50	$33.55	$33.53
-3%, 11000 BTU (KY)	$35.90	$38.45	$37.90	$35.09	$34.98	$35.10	$35.18	$35.26	$35.28	$35.34	$35.38	$35.38
Powder River Basin												
-.33%, 8400 BTU	$12.11	$13.58	$12.68	$12.39	$11.73	$10.74	$10.42	$10.07	$10.10	$10.11	$10.12	$10.07
-.35%, 8800 BTU	$14.06	$15.73	$14.58	$14.22	$13.49	$12.43	$12.13	$11.80	$11.87	$11.93	$11.99	$12.02
Uinta Basin												
-.5%, 11500 BTU	$33.12	$35.19	$34.05	$32.03	$29.60	$28.09	$26.67	$26.06	$25.53	$25.37	$25.24	$25.15
Foreign Coal												
-.7%, 12000 BTU	$88.57	$86.35	$79.15	$70.75	$63.16	$60.25	$59.91	$58.08	$56.35	$55.45	$54.93	$53.38
-.8%, 11600 BTU	$82.66	$80.60	$73.90	$66.09	$59.02	$56.33	$56.04	$54.36	$52.78	$51.97	$51.51	$50.09
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$56.16	$56.54	$52.59	$49.55	$48.06	$47.76	$47.21	$47.11	$46.13	$45.24	$45.14	$43.03

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

ANNUAL AVERAGE CONTR

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$40.83	$41.46	$42.12	$42.78	$43.46	$44.14	$44.81	$45.49	$46.19	$46.89
-1.8%, 13000 BTU	$40.48	$41.10	$41.75	$42.41	$43.08	$43.75	$44.42	$45.10	$45.78	$46.48
-2.3%, 13000 BTU	$39.94	$40.56	$41.20	$41.85	$42.51	$43.18	$43.84	$44.50	$45.18	$45.87
Central Appalachia										
-.7%, 12500 BTU	$69.47	$71.62	$73.49	$75.41	$77.42	$79.49	$81.59	$83.73	$85.89	$88.08
-.7%, 13000 BTU	$74.16	$76.47	$78.48	$80.53	$82.69	$84.91	$87.16	$89.45	$91.76	$94.12
-1.0%, 12500 BTU	$51.04	$52.41	$53.55	$54.71	$55.90	$57.10	$58.31	$59.54	$60.80	$62.11
-1.5%, 12500 BTU	$50.49	$51.87	$53.01	$54.18	$55.37	$56.57	$57.79	$59.02	$60.29	$61.59
Ohio										
-4%, 12500 BTU	$36.43	$37.02	$37.62	$38.23	$38.85	$39.48	$40.10	$40.73	$41.37	$42.01
Illinois Basin										
-3%, 11000 BTU (IL)	$37.21	$37.59	$37.96	$38.33	$38.75	$39.22	$39.68	$40.14	$40.60	$41.08
-3%, 11000 BTU (KY)	$39.67	$40.12	$40.55	$40.99	$41.47	$42.00	$42.54	$43.07	$43.60	$44.14
Powder River Basin										
-.33%, 8400 BTU	$11.71	$12.00	$12.20	$12.39	$12.58	$12.76	$12.94	$13.13	$13.33	$13.54
-.35%, 8800 BTU	$14.74	$15.12	$15.42	$15.71	$16.01	$16.30	$16.60	$16.91	$17.23	$17.59
Uinta Basin										
-.5%, 11500 BTU	$28.36	$28.79	$29.24	$29.69	$30.16	$30.62	$31.09	$31.55	$32.03	$32.50
Foreign Coal										
-.7%, 12000 BTU	$57.21	$58.05	$58.92	$59.85	$60.83	$61.87	$62.93	$64.02	$65.11	$66.18
-.8%, 11600 BTU	$54.54	$55.35	$56.21	$57.11	$58.05	$59.04	$60.06	$61.09	$62.14	$63.15
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$42.33	$42.92	$43.54	$44.21	$44.93	$45.68	$46.48	$47.29	$48.10	$48.88

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE CONTR
BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$31.39	$31.30	$31.21	$31.13	$31.04	$30.94	$30.84	$30.74	$30.64	$30.55
-1.8%, 13000 BTU	$31.11	$31.03	$30.94	$30.86	$30.77	$30.67	$30.57	$30.47	$30.37	$30.28
-2.3%, 13000 BTU	$30.70	$30.62	$30.54	$30.45	$30.37	$30.27	$30.17	$30.07	$29.98	$29.88
Central Appalachia										
-.7%, 12500 BTU	$53.40	$54.06	$54.47	$54.87	$55.30	$55.73	$56.15	$56.57	$56.98	$57.38
-.7%, 13000 BTU	$57.01	$57.72	$58.16	$58.60	$59.06	$59.52	$59.97	$60.43	$60.88	$61.31
-1.0%, 12500 BTU	$39.23	$39.56	$39.69	$39.81	$39.93	$40.03	$40.12	$40.23	$40.34	$40.46
-1.5%, 12500 BTU	$38.81	$39.15	$39.29	$39.42	$39.55	$39.66	$39.76	$39.88	$40.00	$40.12
Ohio										
-4%, 12500 BTU	$28.01	$27.94	$27.88	$27.82	$27.75	$27.67	$27.59	$27.52	$27.44	$27.37
Illinois Basin										
-3%, 11000 BTU (IL)	$28.60	$28.37	$28.13	$27.89	$27.68	$27.49	$27.30	$27.12	$26.94	$26.76
-3%, 11000 BTU (KY)	$30.50	$30.28	$30.05	$29.83	$29.62	$29.45	$29.27	$29.10	$28.92	$28.76
Powder River Basin										
-.33%, 8400 BTU	$9.00	$9.05	$9.04	$9.01	$8.98	$8.94	$8.91	$8.87	$8.84	$8.82
-.35%, 8800 BTU	$11.33	$11.41	$11.43	$11.43	$11.44	$11.43	$11.42	$11.42	$11.43	$11.46
Uinta Basin										
-.5%, 11500 BTU	$21.80	$21.73	$21.67	$21.61	$21.54	$21.47	$21.39	$21.32	$21.25	$21.18
Foreign Coal: Colombia										
-.7%, 12000 BTU	$43.98	$43.82	$43.67	$43.55	$43.45	$43.37	$43.30	$43.25	$43.20	$43.11
-.8%, 11600 BTU	$41.93	$41.78	$41.66	$41.55	$41.47	$41.39	$41.32	$41.28	$41.22	$41.14
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$32.54	$32.40	$32.27	$32.17	$32.09	$32.03	$31.98	$31.95	$31.91	$31.85

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
HIGH CASE
March 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$100.66	$105.96	$77.01	$62.96	$62.98	$63.45	$63.67	$64.41	$65.15	$65.97	$66.70	$67.38
-1.8%, 13000 BTU	$45.85	$98.64	$103.11	$75.40	$61.75	$61.88	$62.46	$62.89	$63.66	$64.43	$65.25	$66.02	$66.75
-2.3%, 13000 BTU	$44.71	$95.60	$98.85	$73.00	$59.95	$60.24	$60.96	$61.71	$62.53	$63.35	$64.18	$65.00	$65.79
Central Appalachia													
-.7%, 12500 BTU	$46.46	$78.41	$104.96	$88.47	$79.60	$70.39	$71.54	$72.66	$73.56	$75.07	$76.90	$78.74	$80.62
-.7%, 13000 BTU	$49.50	$83.56	$111.87	$94.34	$85.03	$75.15	$76.37	$77.57	$78.52	$80.14	$82.09	$84.05	$86.05
-1.0%, 12500 BTU	$44.33	$75.18	$99.12	$81.39	$67.22	$57.05	$54.78	$54.97	$55.37	$56.37	$57.62	$58.78	$59.84
-1.5%, 12500 BTU	$40.72	$57.90	$72.16	$64.93	$60.92	$52.88	$52.88	$53.52	$54.37	$55.58	$56.84	$58.00	$59.12
Ohio													
-4%, 12500 BTU	$39.19	$87.71	$89.29	$66.19	$51.87	$50.95	$50.22	$51.04	$51.96	$53.06	$54.18	$55.28	$56.31
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$43.75	$47.01	$41.11	$39.22	$39.76	$40.32	$40.86	$41.56	$42.37	$43.23	$44.08	$44.98
-3%, 11000 BTU (KY)	$28.91	$46.06	$49.63	$43.34	$41.37	$41.96	$42.60	$43.23	$44.03	$44.93	$45.89	$46.84	$47.84
Powder River Basin													
-.33%, 8400 BTU	$8.36	$15.29	$16.34	$13.55	$11.45	$11.46	$11.52	$11.62	$11.90	$12.27	$12.81	$13.37	$13.92
-.35%, 8800 BTU	$9.85	$16.87	$17.72	$15.13	$13.55	$13.76	$14.06	$14.33	$14.78	$15.33	$15.99	$16.68	$17.42
Uinta Basin													
-.5%, 11500 BTU	$29.93	$48.95	$50.65	$47.38	$44.44	$43.05	$43.10	$42.89	$43.02	$43.15	$42.49	$41.70	$40.18
Foreign Coal													
-.7%, 12000 BTU	$62.03	$136.25	$145.03	$108.60	$93.31	$81.37	$74.60	$70.07	$68.76	$70.07	$71.47	$72.81	$73.94
-.8%, 11600 BTU	$57.85	$127.07	$135.30	$101.49	$87.36	$76.41	$70.24	$66.11	$65.05	$66.48	$67.83	$69.14	$70.30
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$78.30	$106.44	$89.90	$71.58	$60.79	$55.49	$52.08	$51.12	$52.13	$53.07	$53.99	$54.78

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
HIGH CASE
March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$99.03	$102.49	$73.07	$58.55	$57.43	$56.78	$55.90	$55.46	$55.03	$54.67	$54.23	$53.76
-1.8%, 13000 BTU	$45.85	$97.04	$99.74	$71.54	$57.44	$56.43	$55.89	$55.21	$54.81	$54.42	$54.07	$53.67	$53.25
-2.3%, 13000 BTU	$44.71	$94.05	$95.61	$69.26	$55.76	$54.93	$54.56	$54.17	$53.84	$53.50	$53.18	$52.84	$52.49
Central Appalachia													
-.7%, 12500 BTU	$46.46	$77.14	$101.52	$83.93	$74.03	$64.19	$64.02	$63.79	$63.33	$63.40	$63.73	$64.01	$64.32
-.7%, 13000 BTU	$49.50	$82.21	$108.21	$89.51	$79.08	$68.53	$68.34	$68.10	$67.60	$67.68	$68.02	$68.33	$68.66
-1.0%, 12500 BTU	$44.33	$73.96	$95.88	$77.22	$62.52	$52.03	$49.02	$48.26	$47.68	$47.61	$47.75	$47.79	$47.74
-1.5%, 12500 BTU	$40.72	$56.96	$69.80	$61.60	$56.66	$48.22	$47.32	$46.98	$46.81	$46.94	$47.10	$47.15	$47.17
Ohio													
-4%, 12500 BTU	$39.19	$86.29	$86.37	$62.80	$48.24	$46.46	$44.94	$44.81	$44.74	$44.81	$44.90	$44.94	$44.93
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$43.04	$45.47	$39.01	$36.48	$36.26	$36.08	$35.87	$35.79	$35.78	$35.82	$35.84	$35.88
-3%, 11000 BTU (KY)	$28.91	$45.31	$48.01	$41.12	$38.48	$38.26	$38.12	$37.95	$37.91	$37.95	$38.03	$38.08	$38.17
Powder River Basin													
-.33%, 8400 BTU	$8.36	$15.04	$15.80	$12.86	$10.65	$10.45	$10.31	$10.20	$10.25	$10.36	$10.62	$10.87	$11.11
-.35%, 8800 BTU	$9.85	$16.59	$17.14	$14.35	$12.60	$12.54	$12.58	$12.58	$12.73	$12.95	$13.25	$13.56	$13.90
Uinta Basin													
-.5%, 11500 BTU	$29.93	$48.15	$48.99	$44.95	$41.33	$39.26	$38.57	$37.65	$37.04	$36.44	$35.21	$33.90	$32.06
Foreign Coal: Colombia													
-.7%, 12000 BTU	$62.03	$134.05	$140.28	$103.03	$86.78	$74.20	$66.76	$61.52	$59.20	$59.18	$59.22	$59.19	$58.99
-.8%, 11600 BTU	$57.85	$125.02	$130.87	$96.29	$81.26	$69.68	$62.86	$58.03	$56.01	$56.15	$56.21	$56.21	$56.09
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$77.03	$102.96	$85.30	$66.57	$55.43	$49.66	$45.72	$44.02	$44.03	$43.98	$43.89	$43.71

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

HIGH CASE

March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$79.50	$101.35	$109.65	$112.15	$115.60	$109.75	$103.70	$94.80	$86.50	$78.55	$72.90	$70.10
-1.8%, 13000 BTU	$78.19	$99.60	$107.45	$109.30	$112.43	$106.51	$100.95	$92.58	$84.65	$76.71	$71.49	$68.78
-2.3%, 13000 BTU	$76.22	$96.98	$104.16	$105.03	$107.67	$101.65	$96.82	$89.26	$81.87	$73.94	$69.38	$66.81
Central Appalachia												
-.7%, 12500 BTU	$85.30	$107.60	$109.55	$11.20	$109.82	$106.54	$102.59	$100.87	$96.25	$92.58	$85.60	$79.44
-.7%, 13000 BTU	$90.90	$114.64	$116.77	$11.94	$117.05	$113.54	$109.37	$107.51	$102.61	$98.68	$91.27	$84.69
-1.0%, 12500 BTU	$81.92	$102.96	$105.00	$10.75	$104.75	$100.81	$96.60	$94.31	$89.42	$85.39	$78.57	$72.34
-1.5%, 12500 BTU	$72.31	$80.95	$76.75	$7.32	$73.33	$72.38	$71.24	$71.71	$69.48	$67.36	$63.12	$59.51
Ohio												
-4%, 12500 BTU	$70.80	$89.83	$95.29	$94.92	$96.93	$91.77	$87.58	$80.89	$74.26	$67.01	$62.93	$60.55
Illinois Basin												
-3%, 11000 BTU (IL)	$35.40	$44.00	$47.40	$48.20	$49.00	$48.70	$46.00	$44.35	$43.00	$41.35	$40.50	$39.60
-3%, 11000 BTU (KY)	$37.49	$46.21	$49.67	$50.86	$51.78	$51.52	$48.48	$46.77	$45.46	$43.72	$42.60	$41.59
Powder River Basin												
-.33%, 8400 BTU	$13.20	$15.50	$16.10	$16.35	$16.50	$16.50	$16.35	$16.00	$15.00	$14.00	$13.20	$12.00
-.35%, 8800 BTU	$14.85	$17.07	$17.58	$17.97	$17.82	$17.92	$17.68	$17.47	$16.50	$15.55	$14.80	$13.65
Uinta Basin												
-.5%, 11500 BTU	$44.10	$48.54	$51.15	$52.00	$52.00	$51.35	$50.15	$49.10	$48.50	$48.00	$47.00	$46.00
Foreign Coal												
-.7%, 12000 BTU	$119.59	$131.88	$142.88	$150.66	$153.17	$150.04	$141.48	$135.41	$127.86	$112.61	$100.94	$93.01
-.8%, 11600 BTU	$111.56	$123.02	$133.22	$140.49	$142.85	$139.96	$132.02	$126.39	$119.41	$105.21	$94.36	$86.98
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$59.43	$75.05	$81.92	$96.80	$108.30	$107.55	$105.91	$104.02	$100.77	$95.13	$84.03	$79.68

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

HIGH CASE

March 2008

ANNUAL AVERAGE SPOT PF

HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$68.03	$68.88	$69.69	$70.53	$71.37	$72.25	$73.14	$74.04	$74.92	$75.81	$76.71
-1.8%, 13000 BTU	$67.45	$68.28	$69.09	$69.91	$70.75	$71.62	$72.50	$73.39	$74.27	$75.15	$76.04
-2.3%, 13000 BTU	$66.57	$67.38	$68.18	$68.99	$69.82	$70.67	$71.55	$72.43	$73.29	$74.16	$75.04
Central Appalachia											
-.7%, 12500 BTU	$82.55	$84.44	$86.39	$88.40	$90.45	$92.57	$94.32	$96.09	$97.87	$99.66	$101.49
-.7%, 13000 BTU	$88.12	$90.14	$92.24	$94.38	$96.59	$98.86	$100.74	$102.64	$104.55	$106.47	$108.44
-1.0%, 12500 BTU	$61.08	$62.20	$63.41	$64.59	$65.83	$67.07	$67.98	$68.91	$69.81	$70.75	$71.77
-1.5%, 12500 BTU	$60.38	$61.51	$62.74	$63.92	$65.17	$66.43	$67.34	$68.28	$69.20	$70.14	$71.17
Ohio											
-4%, 12500 BTU	$57.53	$60.27	$61.38	$62.57	$63.85	$65.14	$66.32	$67.50	$68.66	$69.86	$71.08
Illinois Basin											
-3%, 11000 BTU (IL)	$45.82	$46.80	$47.77	$48.75	$49.68	$50.66	$51.76	$52.89	$54.02	$55.14	$56.32
-3%, 11000 BTU (KY)	$48.79	$49.87	$50.95	$52.04	$53.09	$54.19	$55.41	$56.67	$57.92	$59.17	$60.49
Powder River Basin											
-.33%, 8400 BTU	$14.56	$15.34	$16.22	$16.93	$17.61	$18.36	$19.04	$19.80	$20.62	$21.38	$22.34
-.35%, 8800 BTU	$18.30	$19.30	$20.41	$21.35	$22.28	$23.32	$24.28	$25.34	$26.47	$27.56	$28.91
Uinta Basin											
-.5%, 11500 BTU	$39.42	$41.10	$42.85	$44.70	$46.63	$48.67	$50.80	$53.02	$55.31	$57.71	$60.25
Foreign Coal											
-.7%, 12000 BTU	$74.94	$76.02	$77.14	$78.28	$79.46	$80.67	$81.94	$83.24	$84.53	$85.85	$87.19
-.8%, 11600 BTU	$71.38	$72.46	$73.55	$74.66	$75.80	$76.98	$78.20	$79.43	$80.67	$81.92	$83.20
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$55.53	$56.29	$57.06	$57.87	$58.71	$59.59	$60.51	$61.46	$62.43	$63.42	$64.42

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

HIGH CASE

March 2008

ANNUAL AVERAGE SPOT PF

HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$53.27	$52.95	$52.61	$52.27	$51.94	$51.60	$51.27	$50.94	$50.62	$50.29	$49.97
-1.8%, 13000 BTU	$52.81	$52.48	$52.15	$51.81	$51.48	$51.15	$50.83	$50.50	$50.18	$49.86	$49.54
-2.3%, 13000 BTU	$52.13	$51.79	$51.46	$51.13	$50.81	$50.48	$50.16	$49.84	$49.52	$49.20	$48.89
Central Appalachia											
-.7%, 12500 BTU	$64.64	$64.91	$65.21	$65.51	$65.82	$66.12	$66.12	$66.12	$66.12	$66.12	$66.12
-.7%, 13000 BTU	$69.00	$69.29	$69.62	$69.95	$70.28	$70.61	$70.62	$70.63	$70.63	$70.64	$70.65
-1.0%, 12500 BTU	$47.82	$47.81	$47.86	$47.87	$47.90	$47.91	$47.65	$47.42	$47.17	$46.94	$46.76
-1.5%, 12500 BTU	$47.28	$47.29	$47.36	$47.38	$47.42	$47.45	$47.21	$46.99	$46.75	$46.54	$46.36
Ohio											
-4%, 12500 BTU	$45.05	$46.33	$46.33	$46.38	$46.46	$46.53	$46.49	$46.44	$46.39	$46.35	$46.31
Illinois Basin											
-3%, 11000 BTU (IL)	$35.88	$35.97	$36.06	$36.13	$36.15	$36.18	$36.29	$36.39	$36.49	$36.58	$36.69
-3%, 11000 BTU (KY)	$38.20	$38.33	$38.46	$38.57	$38.63	$38.70	$38.84	$38.99	$39.13	$39.26	$39.41
Powder River Basin											
-.33%, 8400 BTU	$11.40	$11.79	$12.25	$12.54	$12.81	$13.12	$13.35	$13.63	$13.93	$14.18	$14.55
-.35%, 8800 BTU	$14.33	$14.84	$15.40	$15.82	$16.22	$16.65	$17.02	$17.43	$17.89	$18.29	$18.83
Uinta Basin											
-.5%, 11500 BTU	$30.87	$31.59	$32.34	$33.13	$33.93	$34.76	$35.61	$36.48	$37.37	$38.28	$39.25
Foreign Coal: Colombia											
-.7%, 12000 BTU	$58.68	$58.43	$58.23	$58.02	$57.82	$57.62	$57.45	$57.28	$57.11	$56.95	$56.80
-.8%, 11600 BTU	$55.89	$55.70	$55.51	$55.33	$55.16	$54.99	$54.82	$54.66	$54.50	$54.35	$54.20
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$43.48	$43.27	$43.07	$42.89	$42.72	$42.56	$42.42	$42.29	$42.18	$42.08	$41.96

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

LOW CASE

March 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$59.64	$38.26	$28.06	$27.35	$27.21	$26.90	$26.50	$26.29	$26.12	$25.97	$27.08	$26.85
-1.8%, 13000 BTU	$45.85	$58.49	$37.23	$27.47	$26.82	$26.73	$26.47	$26.17	$25.98	$25.83	$25.69	$26.80	$26.60
-2.3%, 13000 BTU	$44.71	$56.76	$35.69	$26.60	$26.04	$26.02	$25.84	$25.68	$25.52	$25.39	$25.26	$26.39	$26.21
Central Appalachia													
-.7%, 12500 BTU	$46.46	$61.48	$45.93	$42.86	$39.58	$39.23	$39.75	$40.31	$40.77	$41.30	$41.88	$42.50	$43.13
-.7%, 13000 BTU	$49.50	$65.52	$48.95	$45.71	$42.28	$41.88	$42.43	$43.02	$43.52	$44.09	$44.70	$45.37	$46.03
-1.0%, 12500 BTU	$44.33	$58.94	$43.37	$39.43	$33.43	$31.79	$30.44	$30.49	$30.69	$31.02	$31.38	$31.73	$32.01
-1.5%, 12500 BTU	$40.72	$45.40	$31.57	$31.46	$30.29	$29.47	$29.38	$29.69	$30.13	$30.58	$30.96	$31.31	$31.63
Ohio													
-4%, 12500 BTU	$39.19	$52.22	$32.24	$24.12	$22.56	$21.35	$20.65	$20.60	$20.57	$20.63	$20.69	$21.77	$21.77
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$28.94	$26.46	$26.50	$26.88	$26.72	$26.57	$26.40	$26.34	$26.33	$26.34	$26.35	$26.36
-3%, 11000 BTU (KY)	$28.91	$30.48	$27.94	$27.94	$28.36	$28.20	$28.07	$27.93	$27.90	$27.92	$27.96	$27.99	$28.04
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.21	$8.83	$8.71	$9.02	$8.65	$8.36	$8.11	$8.01	$7.96	$8.00	$8.05	$8.10
-.35%, 8800 BTU	$9.85	$11.79	$10.21	$10.29	$10.68	$10.39	$10.19	$10.01	$9.95	$9.94	$9.98	$10.04	$10.13
Uinta Basin													
-.5%, 11500 BTU	$29.93	$29.25	$23.59	$21.23	$20.72	$20.86	$20.61	$20.41	$20.23	$20.07	$19.91	$19.74	$19.60
Foreign Coal													
-.7%, 12000 BTU	$62.03	$82.97	$39.13	$33.57	$32.58	$32.87	$33.13	$33.43	$33.70	$33.97	$34.31	$34.65	$34.95
-.8%, 11600 BTU	$57.85	$77.39	$36.50	$31.38	$30.51	$30.87	$31.19	$31.53	$31.88	$32.23	$32.56	$32.90	$33.23
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$46.38	$28.66	$27.88	$25.00	$24.56	$24.64	$24.84	$25.06	$25.27	$25.48	$25.69	$25.90

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ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$58.67	$37.01	$26.63	$25.43	$24.81	$24.07	$23.26	$22.63	$22.06	$21.52	$22.01	$21.42
-1.8%, 13000 BTU	$45.85	$57.54	$36.01	$26.07	$24.95	$24.38	$23.69	$22.98	$22.37	$21.81	$21.29	$21.79	$21.22
-2.3%, 13000 BTU	$44.71	$55.84	$34.52	$25.24	$24.22	$23.73	$23.13	$22.55	$21.97	$21.45	$20.94	$21.45	$20.92
Central Appalachia													
-.7%, 12500 BTU	$46.46	$60.49	$44.42	$40.67	$36.81	$35.77	$35.57	$35.38	$35.10	$34.88	$34.71	$34.55	$34.41
-.7%, 13000 BTU	$49.50	$64.46	$47.35	$43.37	$39.32	$38.19	$37.97	$37.77	$37.47	$37.24	$37.05	$36.88	$36.73
-1.0%, 12500 BTU	$44.33	$57.99	$41.95	$37.41	$31.09	$28.99	$27.24	$26.77	$26.42	$26.20	$26.01	$25.79	$25.54
-1.5%, 12500 BTU	$40.72	$44.66	$30.54	$29.85	$28.17	$26.87	$26.29	$26.06	$25.95	$25.83	$25.65	$25.45	$25.23
Ohio													
-4%, 12500 BTU	$39.19	$51.38	$31.18	$22.88	$20.98	$19.47	$18.48	$18.09	$17.71	$17.42	$17.14	$17.69	$17.37
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$28.47	$25.60	$25.14	$25.00	$24.37	$23.77	$23.18	$22.68	$22.24	$21.83	$21.42	$21.03
-3%, 11000 BTU (KY)	$28.91	$29.98	$27.02	$26.50	$26.38	$25.71	$25.12	$24.52	$24.02	$23.58	$23.17	$22.76	$22.37
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.05	$8.54	$8.27	$8.39	$7.89	$7.48	$7.12	$6.90	$6.72	$6.63	$6.54	$6.46
-.35%, 8800 BTU	$9.85	$11.60	$9.87	$9.76	$9.93	$9.47	$9.12	$8.78	$8.57	$8.40	$8.27	$8.16	$8.08
Uinta Basin													
-.5%, 11500 BTU	$29.93	$28.78	$22.82	$20.14	$19.27	$19.02	$18.44	$17.92	$17.41	$16.95	$16.50	$16.05	$15.64
Foreign Coal: Colombia													
-.7%, 12000 BTU	$62.03	$81.63	$37.84	$31.85	$30.31	$29.98	$29.65	$29.35	$29.02	$28.69	$28.43	$28.17	$27.89
-.8%, 11600 BTU	$57.85	$76.13	$35.31	$29.77	$28.38	$28.15	$27.92	$27.68	$27.45	$27.22	$26.98	$26.75	$26.51
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$45.63	$27.72	$26.45	$23.25	$22.39	$22.05	$21.81	$21.57	$21.34	$21.11	$20.89	$20.66

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
LOW CASE
March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$71.34	$65.16	$54.32	$47.73	$42.73	$40.60	$36.63	$33.08	$30.64	$29.11	$26.85	$25.65
-1.8%, 13000 BTU	$70.17	$64.04	$53.23	$46.52	$41.56	$39.40	$35.66	$32.31	$29.98	$28.42	$26.33	$25.17
-2.3%, 13000 BTU	$68.40	$62.35	$51.60	$44.70	$39.80	$37.60	$34.20	$31.15	$29.00	$27.40	$25.55	$24.45
Central Appalachia												
-.7%, 12500 BTU	$71.15	$63.22	$57.46	$54.10	$48.35	$46.20	$45.00	$44.15	$43.50	$43.00	$42.75	$42.20
-.7%, 13000 BTU	$75.82	$67.36	$61.24	$57.65	$51.53	$49.23	$47.97	$47.06	$46.37	$45.83	$45.58	$44.99
-1.0%, 12500 BTU	$68.33	$60.50	$55.07	$51.92	$46.12	$43.72	$42.37	$41.28	$40.41	$39.66	$39.24	$38.43
-1.5%, 12500 BTU	$60.31	$47.56	$40.26	$35.33	$32.29	$31.39	$31.25	$31.39	$31.40	$31.29	$31.52	$31.61
Ohio												
-4%, 12500 BTU	$63.54	$57.76	$47.21	$40.40	$35.83	$33.95	$30.94	$28.23	$26.31	$24.83	$23.18	$22.16
Illinois Basin												
-3%, 11000 BTU (IL)	$31.10	$29.65	$28.15	$26.85	$26.50	$26.40	$26.60	$26.35	$26.50	$26.40	$26.60	$26.50
-3%, 11000 BTU (KY)	$32.93	$31.14	$29.50	$28.33	$28.00	$27.93	$28.03	$27.79	$28.02	$27.91	$27.98	$27.83
Powder River Basin												
-.33%, 8400 BTU	$11.35	$10.90	$9.40	$9.20	$9.20	$9.10	$8.60	$8.40	$8.50	$8.40	$9.00	$8.95
-.35%, 8800 BTU	$13.00	$12.47	$10.88	$10.82	$10.52	$10.52	$9.93	$9.87	$10.00	$9.95	$10.60	$10.60
Uinta Basin												
-.5%, 11500 BTU	$33.25	$31.10	$27.40	$25.25	$24.70	$24.00	$23.20	$22.45	$21.70	$21.15	$21.20	$20.85
Foreign Coal												
-.7%, 12000 BTU	$108.53	$92.65	$73.93	$56.78	$46.73	$39.35	$36.28	$34.14	$33.73	$33.50	$33.65	$33.41
-.8%, 11600 BTU	$101.24	$86.43	$68.94	$52.94	$43.58	$36.70	$33.85	$31.87	$31.51	$31.30	$31.45	$31.25
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$53.93	$52.72	$42.39	$36.48	$33.04	$28.21	$27.16	$26.23	$26.59	$28.30	$28.01	$28.62

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

LOW CASE

March 2008

ANNUAL AVERAGE SPOT P

LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$26.62	$26.44	$26.25	$26.06	$25.87	$25.69	$25.52	$25.34	$25.16	$24.98	$24.80
-1.8%, 13000 BTU	$26.39	$26.21	$26.02	$25.83	$25.65	$25.47	$25.30	$25.12	$24.94	$24.76	$24.58
-2.3%, 13000 BTU	$26.05	$25.87	$25.68	$25.49	$25.31	$25.14	$24.96	$24.79	$24.61	$24.43	$24.26
Central Appalachia											
-.7%, 12500 BTU	$43.75	$44.35	$44.96	$45.58	$46.22	$46.87	$47.75	$48.65	$49.55	$50.46	$51.38
-.7%, 13000 BTU	$46.70	$47.34	$48.00	$48.67	$49.35	$50.05	$51.00	$51.96	$52.93	$53.91	$54.90
-1.0%, 12500 BTU	$32.37	$32.67	$33.00	$33.30	$33.64	$33.96	$34.42	$34.89	$35.34	$35.82	$36.33
-1.5%, 12500 BTU	$32.00	$32.31	$32.65	$32.96	$33.30	$33.63	$34.09	$34.57	$35.03	$35.51	$36.03
Ohio											
-4%, 12500 BTU	$21.83	$22.44	$22.42	$22.43	$22.45	$22.47	$22.45	$22.41	$22.37	$22.33	$22.29
Illinois Basin											
-3%, 11000 BTU (IL)	$26.34	$26.39	$26.42	$26.44	$26.43	$26.43	$26.49	$26.55	$26.60	$26.63	$26.68
-3%, 11000 BTU (KY)	$28.05	$28.12	$28.17	$28.23	$28.24	$28.27	$28.36	$28.45	$28.52	$28.58	$28.65
Powder River Basin											
-.33%, 8400 BTU	$8.16	$8.30	$8.43	$8.43	$8.43	$8.44	$8.44	$8.45	$8.45	$8.45	$8.47
-.35%, 8800 BTU	$10.26	$10.44	$10.60	$10.64	$10.67	$10.72	$10.76	$10.81	$10.85	$10.90	$10.96
Uinta Basin											
-.5%, 11500 BTU	$19.49	$19.37	$19.25	$19.14	$19.04	$18.95	$18.87	$18.78	$18.69	$18.61	$18.54
Foreign Coal											
-.7%, 12000 BTU	$35.23	$35.54	$35.86	$36.17	$36.49	$36.81	$37.15	$37.48	$37.81	$38.12	$38.44
-.8%, 11600 BTU	$33.56	$33.88	$34.19	$34.50	$34.81	$35.13	$35.45	$35.77	$36.08	$36.38	$36.68
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$26.11	$26.32	$26.52	$26.74	$26.96	$27.19	$27.43	$27.68	$27.92	$28.17	$28.40

QCF (QUARTERLY
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JD Energy, Inc.
LOW CASE
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ANNUAL AVERAGE SPOT P
LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$20.84	$20.33	$19.81	$19.31	$18.83	$18.35	$17.89	$17.44	$17.00	$16.57	$16.15
-1.8%, 13000 BTU	$20.66	$20.15	$19.64	$19.15	$18.66	$18.19	$17.73	$17.29	$16.85	$16.43	$16.01
-2.3%, 13000 BTU	$20.39	$19.88	$19.38	$18.89	$18.42	$17.95	$17.50	$17.06	$16.63	$16.21	$15.80
Central Appalachia											
-.7%, 12500 BTU	$34.26	$34.09	$33.93	$33.78	$33.63	$33.48	$33.48	$33.48	$33.48	$33.48	$33.48
-.7%, 13000 BTU	$36.57	$36.39	$36.23	$36.07	$35.91	$35.75	$35.75	$35.76	$35.76	$35.76	$35.77
-1.0%, 12500 BTU	$25.34	$25.11	$24.91	$24.68	$24.47	$24.26	$24.13	$24.01	$23.88	$23.76	$23.67
-1.5%, 12500 BTU	$25.06	$24.84	$24.64	$24.43	$24.23	$24.02	$23.90	$23.79	$23.67	$23.56	$23.47
Ohio											
-4%, 12500 BTU	$17.10	$17.25	$16.93	$16.62	$16.34	$16.05	$15.74	$15.42	$15.11	$14.81	$14.52
Illinois Basin											
-3%, 11000 BTU (IL)	$20.63	$20.28	$19.94	$19.60	$19.23	$18.88	$18.57	$18.27	$17.97	$17.67	$17.38
-3%, 11000 BTU (KY)	$21.96	$21.61	$21.27	$20.92	$20.55	$20.20	$19.88	$19.57	$19.27	$18.96	$18.67
Powder River Basin											
-.33%, 8400 BTU	$6.39	$6.38	$6.36	$6.25	$6.14	$6.03	$5.92	$5.81	$5.71	$5.61	$5.52
-.35%, 8800 BTU	$8.03	$8.03	$8.00	$7.88	$7.76	$7.66	$7.54	$7.44	$7.33	$7.23	$7.14
Uinta Basin											
-.5%, 11500 BTU	$15.26	$14.89	$14.53	$14.19	$13.85	$13.54	$13.23	$12.92	$12.63	$12.35	$12.08
Foreign Coal: Colombia											
-.7%, 12000 BTU	$27.59	$27.32	$27.07	$26.81	$26.55	$26.29	$26.04	$25.79	$25.54	$25.29	$25.04
-.8%, 11600 BTU	$26.28	$26.04	$25.80	$25.57	$25.33	$25.09	$24.85	$24.61	$24.38	$24.14	$23.90
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$20.44	$20.23	$20.02	$19.82	$19.62	$19.42	$19.23	$19.05	$18.86	$18.69	$18.50

QCF (QUARTERLY
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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$78.93	$50.48	$41.14	$37.42	$37.73	$37.85	$37.96	$38.34	$38.78	$39.25	$39.67	$40.09
-1.8%, 13000 BTU	$45.85	$77.37	$49.13	$40.29	$36.70	$37.11	$37.30	$37.54	$37.93	$38.39	$38.86	$39.30	$39.74
-2.3%, 13000 BTU	$44.71	$75.05	$47.10	$39.00	$35.63	$36.17	$36.49	$36.89	$37.32	$37.80	$38.27	$38.74	$39.21
Central Appalachia													
-.7%, 12500 BTU	$46.46	$80.24	$57.87	$54.38	$53.33	$54.89	$56.50	$57.62	$58.45	$59.48	$60.69	$62.06	$63.50
-.7%, 13000 BTU	$49.50	$85.51	$61.68	$57.99	$56.97	$58.60	$60.32	$61.50	$62.39	$63.50	$64.78	$66.25	$67.78
-1.0%, 12500 BTU	$44.33	$76.93	$54.65	$50.03	$46.04	$44.76	$44.18	$44.05	$43.98	$44.65	$45.46	$46.32	$47.12
-1.5%, 12500 BTU	$40.72	$59.21	$39.79	$39.91	$40.82	$41.23	$41.77	$42.44	$43.20	$44.04	$44.86	$45.71	$46.57
Ohio													
-4%, 12500 BTU	$39.19	$69.01	$42.54	$35.36	$32.34	$32.85	$33.14	$33.53	$33.93	$34.39	$34.83	$35.27	$35.72
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$35.91	$32.47	$33.37	$35.44	$35.53	$35.73	$36.05	$36.39	$36.77	$37.13	$37.51	$37.90
-3%, 11000 BTU (KY)	$28.91	$37.81	$34.28	$35.18	$37.15	$37.22	$37.43	$37.77	$38.13	$38.52	$38.89	$39.28	$39.68
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.91	$10.88	$10.08	$9.98	$10.07	$10.06	$10.06	$10.11	$10.20	$10.40	$10.59	$10.76
-.35%, 8800 BTU	$9.85	$15.56	$12.30	$11.49	$11.85	$12.08	$12.22	$12.33	$12.48	$12.67	$12.91	$13.15	$13.41
Uinta Basin													
-.5%, 11500 BTU	$29.93	$38.15	$28.99	$25.54	$24.86	$24.00	$24.26	$24.59	$24.93	$25.31	$25.68	$26.05	$26.43
Foreign Coal													
-.7%, 12000 BTU	$62.03	$105.40	$65.52	$56.25	$52.13	$49.89	$49.93	$50.47	$51.00	$51.55	$52.23	$52.93	$53.60
-.8%, 11600 BTU	$57.85	$98.30	$61.13	$52.57	$48.81	$46.84	$47.02	$47.62	$48.25	$48.91	$49.57	$50.27	$50.96
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$59.59	$48.09	$46.66	$39.99	$37.26	$37.14	$37.52	$37.92	$38.35	$38.78	$39.25	$39.72

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ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$77.65	$48.83	$39.03	$34.80	$34.41	$33.87	$33.33	$33.01	$32.75	$32.52	$32.25	$31.99
-1.8%, 13000 BTU	$45.85	$76.12	$47.52	$38.22	$34.14	$33.84	$33.38	$32.95	$32.66	$32.42	$32.20	$31.95	$31.71
-2.3%, 13000 BTU	$44.71	$73.83	$45.55	$37.01	$33.14	$32.99	$32.65	$32.39	$32.13	$31.92	$31.71	$31.49	$31.29
Central Appalachia													
-.7%, 12500 BTU	$46.46	$78.94	$55.98	$51.60	$49.60	$50.05	$50.57	$50.58	$50.33	$50.24	$50.29	$50.45	$50.66
-.7%, 13000 BTU	$49.50	$84.12	$59.66	$55.02	$52.99	$53.44	$53.98	$53.99	$53.72	$53.63	$53.69	$53.86	$54.08
-1.0%, 12500 BTU	$44.33	$75.68	$52.86	$47.47	$42.82	$40.82	$39.54	$38.67	$37.87	$37.71	$37.67	$37.65	$37.60
-1.5%, 12500 BTU	$40.72	$58.25	$38.48	$37.87	$37.97	$37.60	$37.38	$37.25	$37.20	$37.19	$37.17	$37.16	$37.16
Ohio													
-4%, 12500 BTU	$39.19	$67.89	$41.15	$33.55	$30.07	$29.95	$29.66	$29.44	$29.22	$29.04	$28.86	$28.68	$28.50
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$35.33	$31.40	$31.66	$32.96	$32.40	$31.97	$31.65	$31.34	$31.05	$30.77	$30.49	$30.24
-3%, 11000 BTU (KY)	$28.91	$37.20	$33.15	$33.38	$34.55	$33.94	$33.50	$33.16	$32.83	$32.53	$32.23	$31.93	$31.66
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.70	$10.53	$9.56	$9.28	$9.18	$9.00	$8.83	$8.70	$8.61	$8.62	$8.61	$8.59
-.35%, 8800 BTU	$9.85	$15.31	$11.89	$10.90	$11.02	$11.01	$10.94	$10.83	$10.74	$10.70	$10.70	$10.69	$10.70
Uinta Basin													
-.5%, 11500 BTU	$29.93	$37.54	$28.04	$24.23	$23.12	$21.89	$21.71	$21.59	$21.47	$21.38	$21.28	$21.17	$21.09
Foreign Coal: Colombia													
-.7%, 12000 BTU	$62.03	$103.69	$63.38	$53.37	$48.48	$45.49	$44.69	$44.31	$43.92	$43.54	$43.28	$43.03	$42.77
-.8%, 11600 BTU	$57.85	$96.71	$59.13	$49.88	$45.39	$42.71	$42.08	$41.80	$41.55	$41.31	$41.08	$40.87	$40.66
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$58.62	$46.51	$44.27	$37.19	$33.98	$33.24	$32.93	$32.65	$32.39	$32.14	$31.91	$31.69

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ANNUAL AVERAGE SPOT P
BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$40.55	$41.14	$41.66	$42.20	$42.75	$43.32	$43.89	$44.46	$45.02	$45.58	$46.17
-1.8%, 13000 BTU	$40.23	$40.78	$41.30	$41.84	$42.38	$42.94	$43.51	$44.07	$44.63	$45.18	$45.77
-2.3%, 13000 BTU	$39.74	$40.24	$40.75	$41.29	$41.82	$42.38	$42.93	$43.49	$44.04	$44.58	$45.17
Central Appalachia											
-.7%, 12500 BTU	$64.96	$66.46	$67.96	$69.60	$71.22	$72.95	$74.75	$76.56	$78.41	$80.25	$82.15
-.7%, 13000 BTU	$69.34	$70.95	$72.56	$74.32	$76.05	$77.90	$79.83	$81.77	$83.76	$85.74	$87.77
-1.0%, 12500 BTU	$48.05	$48.95	$49.89	$50.86	$51.84	$52.86	$53.88	$54.91	$55.94	$56.98	$58.10
-1.5%, 12500 BTU	$47.51	$48.41	$49.36	$50.33	$51.32	$52.34	$53.36	$54.40	$55.44	$56.48	$57.60
Ohio											
-4%, 12500 BTU	$36.22	$36.70	$37.18	$37.68	$38.19	$38.72	$39.24	$39.77	$40.29	$40.81	$41.37
Illinois Basin											
-3%, 11000 BTU (IL)	$38.32	$38.74	$39.16	$39.59	$40.02	$40.47	$40.92	$41.37	$41.81	$42.24	$42.71
-3%, 11000 BTU (KY)	$40.12	$40.55	$40.98	$41.42	$41.87	$42.33	$42.79	$43.25	$43.70	$44.14	$44.62
Powder River Basin											
-.33%, 8400 BTU	$10.97	$11.11	$11.25	$11.39	$11.51	$11.65	$11.75	$11.87	$11.99	$12.09	$12.24
-.35%, 8800 BTU	$13.74	$13.99	$14.22	$14.45	$14.67	$14.91	$15.12	$15.35	$15.58	$15.80	$16.06
Uinta Basin											
-.5%, 11500 BTU	$26.85	$27.26	$27.67	$28.10	$28.53	$28.98	$29.43	$29.88	$30.33	$30.78	$31.26
Foreign Coal											
-.7%, 12000 BTU	$54.27	$55.01	$55.80	$56.62	$57.49	$58.40	$59.38	$60.40	$61.44	$62.52	$63.57
-.8%, 11600 BTU	$51.69	$52.44	$53.20	$54.00	$54.84	$55.73	$56.67	$57.64	$58.63	$59.66	$60.67
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$40.21	$40.73	$41.28	$41.86	$42.48	$43.14	$43.85	$44.60	$45.37	$46.19	$46.97

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March 2008

ANNUAL AVERAGE SPOT P

BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$31.75	$31.62	$31.44	$31.28	$31.11	$30.94	$30.77	$30.59	$30.41	$30.24	$30.08
-1.8%, 13000 BTU	$31.50	$31.35	$31.17	$31.01	$30.84	$30.67	$30.50	$30.33	$30.15	$29.97	$29.82
-2.3%, 13000 BTU	$31.12	$30.94	$30.76	$30.60	$30.43	$30.27	$30.10	$29.93	$29.75	$29.58	$29.43
Central Appalachia											
-.7%, 12500 BTU	$50.87	$51.09	$51.30	$51.59	$51.82	$52.10	$52.40	$52.68	$52.98	$53.24	$53.52
-.7%, 13000 BTU	$54.30	$54.54	$54.77	$55.08	$55.34	$55.64	$55.96	$56.27	$56.59	$56.88	$57.18
-1.0%, 12500 BTU	$37.62	$37.63	$37.66	$37.69	$37.72	$37.76	$37.77	$37.78	$37.80	$37.80	$37.85
-1.5%, 12500 BTU	$37.20	$37.22	$37.26	$37.30	$37.34	$37.39	$37.41	$37.43	$37.46	$37.47	$37.52
Ohio											
-4%, 12500 BTU	$28.36	$28.21	$28.06	$27.93	$27.79	$27.65	$27.51	$27.37	$27.22	$27.07	$26.95
Illinois Basin											
-3%, 11000 BTU (IL)	$30.01	$29.78	$29.56	$29.34	$29.12	$28.91	$28.69	$28.47	$28.25	$28.02	$27.82
-3%, 11000 BTU (KY)	$31.42	$31.17	$30.93	$30.70	$30.46	$30.23	$30.00	$29.76	$29.52	$29.28	$29.07
Powder River Basin											
-.33%, 8400 BTU	$8.59	$8.54	$8.49	$8.44	$8.38	$8.32	$8.24	$8.17	$8.10	$8.02	$7.97
-.35%, 8800 BTU	$10.76	$10.75	$10.74	$10.71	$10.67	$10.65	$10.60	$10.56	$10.53	$10.48	$10.46
Uinta Basin											
-.5%, 11500 BTU	$21.03	$20.96	$20.89	$20.82	$20.76	$20.70	$20.63	$20.56	$20.49	$20.42	$20.36
Foreign Coal: Colombia											
-.7%, 12000 BTU	$42.50	$42.29	$42.12	$41.96	$41.83	$41.72	$41.63	$41.56	$41.51	$41.48	$41.41
-.8%, 11600 BTU	$40.48	$40.31	$40.16	$40.02	$39.91	$39.81	$39.73	$39.66	$39.61	$39.58	$39.52
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$31.49	$31.31	$31.16	$31.02	$30.91	$30.81	$30.74	$30.69	$30.66	$30.64	$30.60

COAL MONTHLY SPREADSHEET
JD Energy, Inc.
July 2nd, 2008

DIRECTORY

Cell	Item
B13	Price Tables for Coal and Petroleum Coke
T13	Coal Production
T39	Coal Demand

All prices are displayed in nominal $/short ton

Region:	Central Appalachia	Central Appalachia	Central Appalachia	Central Appalachia	Northern Appalachia	Northern Appalachia	Illinois Basin (IL)	Illinois Basin (WKY)	Powder River Basin	Powder River Basin	Uinta Basin (CO)	Petcoke (Gulf)	Petcoke (Gulf)	Petcoke (West Coast)	Colombia Basin (CO)
Market:	Physical	Physical	Physical	NYMEX	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical
SO2/mmBTU	1.2	1.6	2.3	1.6	2.5	3.0-4.0	5.45	5.45	0.8	0.8	0.9	8.6	5.7	5.7	1.4
Sulfur:	0.75%	1.00%	1.40%	1.00%	1.60%	2.30%	3.00%	3.00%	0.33%	0.35%	0.50%	6.00%	4.00%	4.00%	0.80%
BTU/lb:	12,500	12,500	12,500	12,000	13,000	13,000	11,000	11,000	8,400	8,800	11,500	14,000	14,000	14,000	11,300
Mode:	FOB Mine (CSX)	FOB Mine (CSX)	FOB Mine (CSX)	Barge-Big Sandy	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOBT	FOBT	FOBT	FOB Mine
Jan 2006	$61.79	$55.52	$49.23	$55.80	$51.05	$43.32	$27.60	$29.75	$16.00	$20.00	$38.45	$19.87	$27.67	$31.30	$41.41
Feb	$61.09	$55.52	$48.65	$55.95	$49.96	$42.23	$27.35	$29.45	$14.10	$18.15	$38.55	$24.83	$28.12	$32.66	$44.83
Mar	$60.74	$54.27	$49.03	$53.88	$47.88	$39.75	$26.85	$28.90	$12.50	$14.90	$38.35	$30.28	$30.39	$32.66	$49.84
Apr	$60.38	$52.86	$47.32	$52.89	$47.63	$40.14	$26.75	$28.75	$11.15	$14.25	$38.25	$34.25	$33.57	$34.25	$50.09
May	$58.97	$51.82	$46.46	$51.19	$46.59	$39.70	$26.40	$28.45	$10.75	$13.75	$37.90	$36.30	$37.83	$36.38	$47.72
Jun	$58.82	$50.73	$44.98	$49.75	$45.60	$39.30	$26.45	$28.50	$10.00	$12.85	$36.70	$39.70	$43.77	$36.74	$48.64
Jul	$56.55	$49.79	$44.21	$46.63	$44.36	$38.06	$26.10	$28.20	$8.95	$11.45	$36.00	$41.30	$44.45	$40.82	$47.67
Aug	$53.83	$49.95	$44.11	$47.51	$43.81	$38.31	$26.70	$28.80	$8.25	$10.45	$35.45	$38.10	$43.09	$43.09	$49.73
Sep	$52.32	$49.32	$43.96	$45.35	$44.26	$39.35	$27.10	$29.15	$7.40	$8.65	$36.05	$38.55	$43.32	$44.45	$44.68
Oct	$50.86	$47.81	$43.75	$43.12	$43.81	$39.75	$27.45	$29.45	$7.80	$9.45	$36.00	$39.35	$43.91	$41.64	$45.13
Nov	$49.45	$46.77	$43.19	$40.82	$42.92	$39.50	$27.70	$29.70	$7.80	$9.80	$34.95	$36.05	$38.78	$38.78	$45.93
Dec	$46.17	$44.11	$40.93	$41.89	$41.98	$38.16	$27.65	$29.60	$7.30	$9.15	$34.45	$38.55	$43.09	$40.37	$46.44
Jan 2007	$42.90	$40.55	$36.90	$39.55	$44.05	$41.10	$26.60	$28.50	$7.15	$8.85	$34.20	$43.18	$51.35	$46.09	$46.16
Feb	$40.90	$38.20	$34.00	$40.72	$44.25	$42.15	$26.90	$28.80	$7.35	$8.95	$33.55	$44.00	$52.45	$47.63	$47.57
Mar	$41.95	$39.90	$35.65	$41.07	$43.70	$41.95	$27.05	$29.00	$7.05	$8.60	$33.50	$44.91	$52.63	$48.76	$48.22
Apr	$43.90	$41.70	$38.00	$41.88	$45.05	$43.40	$26.85	$28.85	$7.00	$8.45	$33.55	$46.38	$52.80	$49.10	$46.89
May	$45.00	$43.00	$39.90	$43.97	$44.35	$42.35	$26.55	$28.55	$7.45	$8.85	$33.50	$48.13	$53.13	$49.94	$46.22
Jun	$45.30	$42.90	$39.75	$46.93	$44.85	$43.05	$26.20	$28.15	$8.00	$9.50	$30.45	$48.53	$53.18	$50.58	$51.96
Jul	$45.55	$43.50	$40.20	$43.86	$46.35	$44.35	$26.65	$28.50	$8.50	$10.05	$27.95	$48.53	$53.18	$51.14	$53.19
Aug	$45.60	$43.55	$40.05	$43.08	$46.65	$44.70	$27.10	$28.90	$9.05	$10.65	$26.45	$44.79	$48.28	$51.44	$54.78
Sep	$45.80	$43.90	$40.25	$44.13	$46.80	$44.95	$27.05	$28.90	$9.20	$10.70	$26.65	$41.62	$46.55	$51.65	$56.53
Oct	$50.55	$48.55	$44.70	$46.87	$48.75	$46.95	$27.65	$29.55	$9.45	$10.90	$26.90	$42.07	$46.38	$51.26	$66.68
Nov	$53.95	$52.15	$48.10	$51.82	$49.50	$48.00	$27.95	$29.80	$9.80	$11.05	$26.10	$42.07	$46.55	$56.02	$82.33
Dec	$56.15	$54.10	$51.15	$53.65	$55.05	$53.55	$27.60	$29.45	$10.30	$11.65	$26.30	$44.57	$48.42	$60.33	$86.75
Jan 2008	$60.70	$58.65	$55.75	$62.96	$62.60	$60.30	$28.05	$29.95	$10.65	$12.40	$28.85	$46.95	$51.48	$62.78	$92.19
Feb	$77.75	$74.45	$65.95	$82.50	$74.30	$71.20	$31.95	$33.85	$11.95	$14.30	$35.50	$55.11	$59.99	$65.09	$105.60
Mar	$82.75	$79.30	$73.45	$76.85	$82.45	$79.60	$35.15	$37.10	$12.10	$14.50	$38.75	$56.98	$66.40	$71.56	$102.17
Apr	$87.40	$84.25	$78.55	$89.95	$102.10	$96.20	$43.10	$45.10	$11.85	$14.40	$43.35	$59.10	$70.99	$74.84	$100.33
May	$102.40	$99.40	$91.30	$104.95	$105.25	$101.60	$49.25	$51.25	$11.60	$14.10	$51.90	$64.86	$79.29	$100.92	$112.38
Jun	$118.40	$115.00	$106.25	$119.54	$113.15	$108.40	$53.00	$54.95	$11.15	$13.25	$56.65	$74.16	$84.82	$113.67	$130.07
Jul	$161.45	$158.45	$148.95	$167.36	$158.78	$152.83	$59.00	$60.85	$10.60	$12.40	$61.40	$96.79	$113.04	$135.64	$173.45
Aug	$167.08	$164.08	$153.13	$172.80	$164.73	$158.68	$59.65	$61.45	$11.05	$12.75	$62.10	$103.69	$120.04	$142.59	$179.08
Sep	$171.34	$168.34	$157.24	$178.67	$169.09	$163.09	$60.05	$61.90	$11.60	$13.20	$62.55	$108.36	$124.86	$147.46	$183.34
Oct	$173.52	$170.52	$159.22	$179.08	$171.37	$165.42	$60.20	$62.10	$11.80	$13.55	$63.40	$110.57	$127.32	$149.72	$185.52
Nov	$171.97	$169.02	$157.57	$177.25	$169.67	$163.87	$60.50	$62.35	$11.90	$13.80	$62.90	$111.33	$128.18	$150.53	$184.02
Dec	$169.78	$167.03	$155.43	$172.96	$167.53	$161.88	$60.75	$62.60	$12.05	$13.80	$61.25	$111.58	$128.08	$150.88	$182.03
Jan 2009	$167.79	$164.99	$153.19	$168.58	$165.19	$159.79	$60.75	$62.55	$12.35	$13.90	$61.00	$111.95	$127.85	$151.30	$179.99
Feb	$165.43	$162.58	$150.43	$164.57	$162.58	$157.33	$60.25	$62.05	$12.30	$13.70	$59.85	$112.76	$128.76	$152.16	$177.58
Mar	$162.40	$159.50	$147.05	$160.55	$159.40	$154.20	$59.80	$61.65	$12.00	$13.35	$56.45	$105.75	$121.85	$145.25	$174.50
Apr	$155.78	$152.83	$140.08	$152.44	$152.53	$147.48	$58.85	$60.70	$11.80	$13.20	$52.70	$94.99	$111.19	$134.54	$167.83
May	$140.01	$136.91	$123.91	$134.47	$136.51	$131.51	$56.60	$58.50	$11.50	$12.95	$49.75	$79.60	$96.00	$119.50	$151.91
Jun	$117.84	$114.64	$101.44	$111.67	$114.19	$109.24	$53.70	$55.55	$11.20	$12.60	$46.95	$65.73	$81.53	$105.73	$129.64
Jul	$107.73	$104.48	$91.38	$102.71	$103.88	$99.03	$50.45	$52.25	$10.85	$12.20	$47.30	$59.62	$75.02	$99.77	$119.48
Aug	$102.66	$99.31	$86.26	$97.84	$98.56	$93.81	$48.20	$49.95	$10.55	$11.85	$45.65	$59.41	$74.31	$99.76	$114.31
Sep	$99.71	$96.31	$83.46	$94.17	$95.41	$90.76	$44.65	$46.40	$10.05	$11.40	$42.80	$60.15	$74.55	$100.35	$111.31
Oct	$96.27	$92.77	$80.27	$91.45	$91.72	$87.12	$42.10	$43.90	$9.30	$10.80	$39.90	$60.47	$74.27	$100.57	$107.77
Nov	$92.20	$88.60	$76.40	$89.24	$87.25	$82.90	$39.95	$41.75	$9.15	$10.65	$36.35	$60.28	$73.38	$100.28	$103.60
Dec	$86.99	$83.29	$71.49	$84.05	$81.64	$77.54	$37.30	$39.05	$9.55	$10.95	$33.45	$59.22	$71.82	$96.62	$98.29
Jan 2010	$82.15	$78.35	$66.75	$79.35	$76.40	$72.55	$35.50	$37.30	$9.75	$11.30	$31.80	$58.18	$70.28	$92.28	$93.35
Feb	$78.39	$74.49	$62.94	$74.83	$72.19	$68.59	$35.20	$37.00	$9.90	$11.30	$31.50	$57.63	$69.33	$88.79	$89.49
Mar	$73.73	$69.73	$58.63	$69.33	$66.93	$63.73	$34.45	$36.30	$9.85	$11.20	$29.50	$56.32	$67.32	$84.87	$84.73
Apr	$68.61	$64.51	$53.86	$63.46	$61.31	$58.36	$33.40	$35.25	$9.70	$11.10	$27.85	$54.50	$64.90	$80.05	$79.51
May	$63.59	$59.39	$49.34	$57.85	$55.74	$53.04	$32.85	$34.75	$9.55	$11.00	$26.00	$52.52	$62.32	$75.07	$74.39
Jun	$59.74	$55.44	$45.54	$55.52	$51.19	$48.79	$33.20	$35.05	$9.85	$11.25	$25.40	$51.20	$59.80	$70.75	$70.44
Jul	$59.50	$55.10	$44.80	$55.64	$50.40	$48.20	$33.60	$35.40	$10.20	$11.55	$25.60	$49.37	$57.17	$65.92	$66.04
Aug	$60.40	$55.90	$45.90	$56.65	$50.60	$48.70	$34.20	$35.95	$10.80	$12.10	$25.80	$48.05	$54.90	$63.25	$62.55
Sep	$58.35	$53.75	$44.40	$53.70	$48.20	$46.35	$34.00	$35.75	$10.50	$11.85	$25.50	$46.09	$53.09	$61.04	$58.42
Oct	$56.20	$51.50	$42.25	$50.44	$45.75	$43.85	$33.75	$35.55	$10.20	$11.70	$25.30	$44.07	$51.32	$58.67	$54.43
Nov	$54.10	$49.30	$40.85	$49.24	$43.25	$41.40	$33.60	$35.40	$10.25	$11.75	$25.30	$42.18	$49.48	$54.98	$50.80
Dec	$53.55	$48.65	$40.30	$49.01	$42.30	$40.50	$33.40	$35.15	$10.40	$11.80	$25.35	$40.14	$47.39	$51.34	$47.17

COAL MONTHLY SPREADSHEET
JD Energy, Inc.
July 2nd, 2008

PRODUCTION

TOTAL PRODUCTION (Millions of Tons)

	Q1	Q2	Q3	Q4	Total	% Change
2006	289.1	292.4	289.8	291.4	1,162.7	2.76%
2007	285.9	285.6	285.8	288.3	1,145.6	-1.48%
2008	289.1	288.5	295.1	290.9	1,163.6	1.58%
2009	291.5	285.6	289.9	291.0	1,158.7	-0.42%

APPALACHIAN PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2006	103.5	100.3	94.3	93.8	391.9	-1.38%
2007	99.5	95.5	91.4	91.4	377.8	-3.59%
2008	97.8	99.2	98.6	95.8	391.4	3.60%
2009	95.6	93.5	94.3	95.2	379.4	-3.09%

INTERIOR PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2006	37.6	36.8	38.8	38.2	151.4	1.50%
2007	38.0	36.3	36.9	35.5	146.7	-3.10%
2008	35.5	39.4	39.2	38.9	153.0	4.29%
2009	38.6	37.9	38.6	38.7	153.8	0.48%

WESTERN PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2006	148.0	155.3	156.8	159.4	619.4	5.89%
2007	148.4	153.8	157.4	161.4	621.0	0.25%
2008	155.8	149.8	157.3	156.2	619.2	-0.30%
2009	157.3	154.1	157.0	157.1	625.6	1.04%

DEMAND

Millions of Tons	2004	2005	2006	2007	2008	2009
Elec Power	1013.5	1030.8	1021.2	1039.2	1045.4	1044.2
Industrial	53.0	52.7	51.5	50.3	52.5	52.5
Coke Plants	23.7	23.4	23.0	22.7	22.7	23.4
Resident/Com.	4.1	3.7	3.7	3.9	4.1	4.1
Total Domestic	1,094.3	1,110.6	1,099.4	1,116.1	1,124.7	1,124.2
+Exports	48.0	49.9	49.6	59.2	85.1	70.1
-Imports	27.3	30.5	36.2	36.3	31.7	32.8
Stock Change	-11.5	-9.7	42.6	2.5	-14.4	-2.8
Production	1,112.1	1,131.5	1,162.7	1,145.6	1,163.6	1,158.7
Discrepancy	-8.5	-11.1	-7.3	-4.1	0.0	0.0

NOTE: Both Production and Demand numbers exclude waste coal; Electric Power consumption data includes electricty generation from all sectors including the electric, industrial and commerical sectors. Non-electricity output from both the electricity and industrial sectors are included under the Industrial category.

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

	Cell
ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON	A14
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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	$25.59	$26.41	$24.85	$24.45	$26.34	$26.04	$24.94	$23.65	$24.09	$40.52	$30.37	$31.04	$50.27	$54.42	$45.82	$46.61	$109.29	$100.38	$56.06	$41.01
-1.8%, 13000 BTU	$25.06	$25.55	$23.49	$22.21	$22.51	$22.89	$23.59	$22.12	$23.07	$39.46	$29.38	$29.83	$48.89	$52.23	$43.41	$45.85	$107.07	$98.45	$55.05	$40.30
-2.3%, 13000 BTU	$22.40	$21.72	$21.48	$20.71	$21.26	$21.79	$22.54	$20.65	$22.05	$35.99	$27.51	$28.67	$47.91	$48.94	$39.80	$44.71	$103.75	$95.54	$53.54	$39.25
Central Appalachia																				
-.7%, 12500 BTU	$24.31	$26.02	$26.75	$24.86	$26.01	$25.45	$25.97	$24.50	$24.90	$47.09	$29.20	$34.27	$58.62	$61.97	$55.91	$46.46	$108.30	$105.04	$64.73	$56.86
-.7%, 13000 BTU	$26.08	$27.58	$28.31	$26.60	$25.80	$25.25	$25.77	$25.15	$26.42	$50.06	$31.07	$36.49	$62.42	$66.01	$59.56	$49.50	$115.41	$111.96	$69.02	$60.74
-1.0%, 12500 BTU	$21.94	$24.01	$24.22	$22.84	$24.41	$24.02	$24.24	$23.29	$23.45	$44.09	$27.25	$32.04	$55.03	$57.49	$50.71	$44.33	$105.29	$101.83	$60.38	$48.01
-1.5%, 12500 BTU	$21.54	$22.92	$22.70	$21.72	$22.73	$23.05	$23.33	$22.07	$21.72	$38.50	$24.19	$29.19	$49.92	$53.18	$45.49	$40.72	$93.27	$88.15	$50.33	$43.51
Ohio																				
-4%, 12500 BTU	$19.79	$21.50	$20.83	$18.38	$18.25	$18.34	$18.05	$18.41	$18.89	$26.44	$20.72	$23.01	$33.25	$35.88	$32.55	$39.19	$81.14	$78.23	$48.35	$35.60
Illinois Basin																				
-3%, 11000 BTU (IL)	$18.93	$21.68	$19.85	$16.96	$17.71	$18.10	$18.25	$17.44	$16.83	$24.63	$19.71	$19.61	$26.12	$27.54	$27.01	$27.01	$50.75	$54.48	$38.12	$34.89
-3%, 11000 BTU (KY)	$20.03	$22.78	$20.95	$18.10	$19.29	$20.25	$19.90	$18.81	$17.51	$29.93	$23.34	$22.09	$29.18	$29.82	$29.06	$28.91	$52.65	$56.29	$39.93	$36.70
Powder River Basin																				
-.33%, 8400 BTU	$3.58	$3.26	$4.34	$3.60	$3.09	$3.13	$3.35	$3.45	$3.43	$7.58	$4.74	$5.13	$5.23	$7.96	$10.17	$8.36	$11.77	$11.99	$11.08	$11.13
-.35%, 8800 BTU	$4.58	$4.64	$5.08	$4.68	$4.11	$4.29	$4.45	$4.42	$4.38	$9.34	$5.85	$6.21	$6.26	$10.09	$12.74	$9.85	$13.78	$13.40	$12.50	$12.97
Uinta Basin																				
-.5%, 11500 BTU	$19.79	$19.35	$13.64	$14.05	$13.58	$15.18	$15.09	$14.16	$13.35	$20.06	$16.95	$17.13	$26.82	$33.11	$36.76	$29.93	$59.78	$54.61	$27.08	$25.68
Foreign Coal																				
-.7%, 12000 BTU	$28.74	$26.45	$28.05	$34.31	$32.76	$31.71	$29.31	$26.35	$27.89	$35.37	$27.70	$33.43	$59.18	$50.12	$50.53	$62.03	$125.45	$115.01	$76.58	$54.42
-.8%, 11600 BTU						$29.61	$26.70	$24.09	$25.79	$32.94	$26.04	$31.41	$55.40	$46.90	$47.22	$57.85	$117.00	$107.30	$71.56	$50.95
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			$15.42	$12.55	$18.22	$19.39	$3.52	$1.71	$9.98	$12.73	$8.57	$13.03	$11.27	$17.50	$34.76	$44.90	$66.62	$58.65	$50.02	$40.71

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	**$36.16**	**$36.49**	**$33.62**	**$32.42**	**$34.28**	**$33.32**	**$31.57**	**$29.51**	**$29.41**	**$48.32**	**$35.59**	**$35.62**	**$56.08**	**$58.81**	**$48.00**	**$47.57**	**$109.29**	**$98.34**	**$53.89**	**$38.64**
-1.8%, 13000 BTU	**$35.42**	**$35.29**	**$31.77**	**$29.45**	**$29.29**	**$29.29**	**$29.86**	**$27.60**	**$28.17**	**$47.05**	**$34.43**	**$34.23**	**$54.54**	**$56.44**	**$45.48**	**$46.79**	**$107.07**	**$96.44**	**$52.92**	**$37.98**
-2.3%, 13000 BTU	**$31.66**	**$30.00**	**$29.05**	**$27.46**	**$27.67**	**$27.89**	**$28.53**	**$25.77**	**$26.93**	**$42.92**	**$32.24**	**$32.90**	**$53.44**	**$52.88**	**$41.69**	**$45.62**	**$103.75**	**$93.59**	**$51.47**	**$36.98**
Central Appalachia																				
-.7%, 12500 BTU	**$34.35**	**$35.95**	**$36.19**	**$32.96**	**$33.84**	**$32.58**	**$32.88**	**$30.57**	**$30.40**	**$56.15**	**$34.22**	**$39.33**	**$65.39**	**$66.97**	**$58.57**	**$47.41**	**$108.30**	**$102.90**	**$62.23**	**$53.57**
-.7%, 13000 BTU	**$36.85**	**$38.09**	**$38.30**	**$35.26**	**$33.57**	**$32.32**	**$32.61**	**$31.38**	**$32.26**	**$59.69**	**$36.41**	**$41.88**	**$69.63**	**$71.33**	**$62.40**	**$50.52**	**$115.41**	**$109.68**	**$66.36**	**$57.23**
-1.0%, 12500 BTU	**$31.01**	**$33.17**	**$32.76**	**$30.28**	**$31.77**	**$30.75**	**$30.69**	**$29.07**	**$28.64**	**$52.58**	**$31.94**	**$36.77**	**$61.39**	**$62.12**	**$53.12**	**$45.24**	**$105.29**	**$99.75**	**$58.05**	**$45.24**
-1.5%, 12500 BTU	**$30.44**	**$31.67**	**$30.70**	**$28.79**	**$29.58**	**$29.50**	**$29.54**	**$27.54**	**$26.52**	**$45.91**	**$28.35**	**$33.50**	**$55.69**	**$57.47**	**$47.65**	**$41.55**	**$93.27**	**$86.35**	**$48.39**	**$41.00**
Ohio																				
-4%, 12500 BTU	**$27.97**	**$29.70**	**$28.17**	**$24.36**	**$23.75**	**$23.47**	**$22.85**	**$22.97**	**$23.06**	**$31.53**	**$24.29**	**$26.41**	**$37.10**	**$38.77**	**$34.09**	**$39.99**	**$81.14**	**$76.63**	**$46.49**	**$33.55**
Illinois Basin																				
-3%, 11000 BTU (IL)	**$26.75**	**$29.94**	**$26.85**	**$22.49**	**$23.05**	**$23.17**	**$23.10**	**$21.76**	**$20.55**	**$29.37**	**$23.10**	**$22.51**	**$29.14**	**$29.76**	**$28.29**	**$27.56**	**$50.75**	**$53.37**	**$36.65**	**$32.87**
-3%, 11000 BTU (KY)	**$28.30**	**$31.46**	**$28.34**	**$24.00**	**$25.10**	**$25.92**	**$25.19**	**$23.47**	**$21.38**	**$35.69**	**$27.35**	**$25.35**	**$32.55**	**$32.22**	**$30.44**	**$29.50**	**$52.65**	**$55.14**	**$38.38**	**$34.58**
Powder River Basin																				
-.33%, 8400 BTU	**$5.06**	**$4.51**	**$5.87**	**$4.77**	**$4.02**	**$4.00**	**$4.24**	**$4.30**	**$4.18**	**$9.03**	**$5.55**	**$5.88**	**$5.83**	**$8.60**	**$10.65**	**$8.53**	**$11.77**	**$11.75**	**$10.66**	**$10.48**
-.35%, 8800 BTU	**$6.47**	**$6.41**	**$6.87**	**$6.20**	**$5.35**	**$5.49**	**$5.63**	**$5.52**	**$5.34**	**$11.13**	**$6.86**	**$7.13**	**$6.99**	**$10.90**	**$13.34**	**$10.05**	**$13.78**	**$13.12**	**$12.01**	**$12.22**
Uinta Basin																				
-.5%, 11500 BTU	**$27.97**	**$26.73**	**$18.45**	**$18.63**	**$17.66**	**$19.42**	**$19.10**	**$17.67**	**$16.30**	**$23.92**	**$19.87**	**$19.65**	**$29.92**	**$35.77**	**$38.51**	**$30.54**	**$59.78**	**$53.50**	**$26.03**	**$24.20**
Foreign Coal: Colombia																				
-.7%, 12000 BTU	**$40.61**	**$36.54**	**$37.95**	**$45.49**	**$42.63**	**$40.59**	**$37.10**	**$32.88**	**$34.05**	**$42.18**	**$32.46**	**$38.36**	**$66.02**	**$54.16**	**$52.93**	**$63.30**	**$125.45**	**$112.67**	**$73.63**	**$51.27**
-.8%, 11600 BTU						**$37.90**	**$33.80**	**$30.06**	**$31.49**	**$39.28**	**$30.51**	**$36.05**	**$61.80**	**$50.68**	**$49.47**	**$59.03**	**$117.00**	**$105.11**	**$68.80**	**$48.01**
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			**$20.86**	**$16.64**	**$23.71**	**$24.82**	**$4.45**	**$2.13**	**$12.19**	**$15.18**	**$10.04**	**$14.95**	**$12.58**	**$18.91**	**$36.41**	**$45.82**	**$66.62**	**$57.46**	**$48.09**	**$38.35**
IMPLICIT PRICE DEFLATOR (GDP)	86.40	88.39	90.27	92.10	93.85	95.41	96.47	97.86	100.00	102.40	104.19	106.40	109.46	113.00	116.57	119.66	122.11	124.65	127.01	129.59
% Change	2.77%	2.30%	2.12%	2.04%	1.89%	1.67%	1.11%	1.44%	2.18%	2.40%	1.75%	2.13%	2.87%	3.23%	3.16%	2.66%	2.04%	2.08%	1.89%	2.03%

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	1995		1996		1996	1996	1997		1997		1998		1998		1999				2000	
Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Northern Appalachia																				
-1.6%, 13000 BTU	$24.73	$24.68	$26.27	$24.93	$26.76	$27.41	$26.76	$25.67	$25.77	$25.94	$25.72	$24.63	$24.63	$24.78	$24.43	$23.54	$23.29	$23.34	$22.90	$22.95
-1.8%, 13000 BTU	$22.15	$22.10	$23.29	$22.10	$22.35	$22.30	$22.40	$22.30	$23.05	$23.79	$23.79	$23.29	$23.84	$23.44	$22.80	$21.66	$21.41	$22.60	$22.03	$22.00
-2.3%, 13000 BTU	$20.96	$20.87	$21.81	$20.91	$21.21	$21.11	$21.21	$21.16	$22.01	$22.80	$22.80	$22.25	$22.80	$22.30	$21.51	$19.73	$19.92	$21.46	$21.11	$20.96
Central Appalachia																				
-.7%, 12500 BTU	$24.95	$24.70	$25.71	$24.50	$26.86	$26.97	$27.17	$24.55	$24.50	$25.60	$25.64	$25.27	$26.28	$26.71	$25.91	$24.14	$23.89	$24.04	$23.54	$23.39
-.7%, 13000 BTU	$26.49	$26.23	$25.50	$24.30	$26.65	$26.75	$26.95	$24.35	$24.30	$25.40	$25.43	$25.07	$26.07	$26.50	$25.70	$23.95	$25.46	$25.50	$24.96	$24.78
-1.0%, 12500 BTU	$22.92	$22.81	$24.11	$23.54	$24.90	$25.10	$25.21	$23.59	$23.33	$23.96	$24.06	$23.33	$24.48	$25.10	$24.32	$23.13	$22.92	$22.81	$22.34	$22.19
-1.5%, 12500 BTU	$21.61	$21.46	$22.50	$21.56	$23.44	$23.44	$23.54	$23.13	$22.40	$23.13	$23.18	$22.81	$23.33	$24.01	$23.13	$22.03	$21.82	$21.30	$20.73	$20.63
Ohio																				
-4%, 12500 BTU	$18.35	$18.25	$18.25	$18.20	$18.30	$18.25	$18.40	$18.30	$18.35	$18.30	$18.30	$18.10	$18.10	$17.70	$18.35	$18.00	$18.40	$18.90	$19.00	$18.25
Illinois Basin																				
-3%, 11000 BTU (IL)	$16.70	$ 16.85	$ 17.50	$ 17.35	$ 18.00	$ 18.00	$18.00	$18.00	$18.15	$18.25	$18.25	$17.95	$ 18.20	$ 18.60	$18.10	$17.50	$17.15	$17.00	$16.75	$16.70
-3%, 11000 BTU (KY)	$17.80	$ 18.10	$ 18.75	$ 18.50	$ 19.90	$ 20.00	$21.00	$20.05	$20.00	$19.95	$20.05	$19.35	$ 20.00	$ 20.20	$19.75	$19.00	$18.45	$18.05	$17.20	$16.95
Powder River Basin																				
-.33%, 8400 BTU	$3.40	$3.30	$3.20	$3.15	$3.00	$3.00	$3.00	$3.00	$3.20	$3.30	$3.62	$3.35	$3.15	$3.27	$3.38	$3.45	$3.47	$3.50	$3.40	$3.20
-.35%, 8800 BTU	$4.45	$4.40	$4.25	$4.20	$4.00	$4.00	$4.00	$4.05	$4.50	$4.60	$4.80	$4.45	$4.20	$4.34	$4.38	$4.45	$4.40	$4.45	$4.40	$4.20
Uinta Basin																				
-.5%, 11500 BTU	$14.20	$14.00	$13.50	$13.20	$13.60	$14.00	$14.40	$15.05	$15.65	$15.60	$15.25	$15.20	$ 15.10	$ 14.80	$14.65	$14.40	$14.10	$13.50	$12.75	$12.80
Foreign Coal																				
-.7%, 12000 BTU	$34.20	$34.50	$33.65	$32.15	$32.00	$33.25	$33.50	$32.40	$30.95	$30.00	$29.20	$29.00	$30.15	$28.90	$28.40	$28.00	$24.60	$24.40	$26.00	$27.25
-.8%, 11600 BTU							$31.54	$30.51	$28.69	$27.71	$26.61	$26.08	$27.99	$26.13	$25.63	$24.63	$23.34	$22.75	$24.13	$25.21
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$10.28	$11.79	$15.88	$17.24	$19.35	$20.41	$21.47	$21.02	$19.81	$15.27	$7.41	$3.93	$1.36	$1.36	$1.36	$1.36	$1.36	$2.75	$5.58	$5.73

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

ANNUAL AVERAGE SPOT
BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$40.45	$40.62	$40.76	$41.25	$41.81	$42.47	$43.15	$43.90	$44.70	$45.69	$46.51	$47.37	$48.20	$49.01	$49.86	$50.76	$51.64	$52.51	$53.40
-1.8%, 13000 BTU	$39.84	$40.08	$40.34	$40.84	$41.42	$42.09	$42.78	$43.56	$44.38	$45.29	$46.10	$46.96	$47.78	$48.58	$49.42	$50.32	$51.19	$52.05	$52.94
-2.3%, 13000 BTU	$38.91	$39.27	$39.70	$40.24	$40.84	$41.51	$42.22	$43.04	$43.90	$44.69	$45.50	$46.34	$47.15	$47.94	$48.77	$49.66	$50.52	$51.37	$52.24
Central Appalachia																			
-.7%, 12500 BTU	$59.48	$60.96	$62.60	$64.03	$63.36	$63.77	$64.55	$66.30	$68.03	$69.88	$71.77	$73.91	$76.11	$79.24	$82.59	$85.18	$87.81	$90.43	$93.05
-.7%, 13000 BTU	$63.50	$65.08	$66.83	$68.34	$67.63	$68.08	$68.90	$70.77	$72.62	$74.60	$76.62	$78.91	$81.28	$84.63	$88.20	$90.98	$93.81	$96.61	$99.42
-1.0%, 12500 BTU	$48.21	$47.70	$47.36	$48.20	$47.58	$47.80	$48.18	$49.22	$50.34	$51.48	$52.68	$54.00	$55.39	$57.41	$59.52	$61.09	$62.64	$64.19	$65.80
-1.5%, 12500 BTU	$44.68	$45.39	$46.11	$47.33	$46.91	$47.15	$47.54	$48.63	$49.76	$50.91	$52.12	$53.45	$54.84	$56.86	$58.96	$60.53	$62.08	$63.64	$65.24
Ohio																			
-4%, 12500 BTU	$35.32	$35.66	$36.07	$36.57	$37.13	$37.76	$38.43	$39.19	$39.99	$40.74	$41.49	$42.28	$43.04	$43.78	$44.56	$45.39	$46.20	$47.00	$47.82
Illinois Basin																			
-3%, 11000 BTU (IL)	$35.09	$35.32	$35.67	$36.02	$36.40	$36.79	$37.22	$37.74	$38.31	$38.80	$39.29	$39.79	$40.26	$40.70	$41.16	$41.67	$42.14	$42.60	$43.07
-3%, 11000 BTU (KY)	$36.91	$37.20	$37.61	$38.02	$38.45	$38.89	$39.38	$39.96	$40.58	$41.14	$41.68	$42.25	$42.77	$43.28	$43.81	$44.38	$44.92	$45.44	$45.97
Powder River Basin																			
-.33%, 8400 BTU	$10.78	$10.61	$10.52	$10.60	$10.69	$10.93	$11.14	$11.38	$11.63	$12.02	$12.39	$12.62	$12.82	$13.02	$13.22	$13.45	$13.66	$13.87	$14.08
-.35%, 8800 BTU	$12.77	$12.75	$12.78	$12.95	$13.14	$13.41	$13.67	$14.01	$14.38	$14.88	$15.33	$15.66	$15.96	$16.26	$16.57	$16.89	$17.22	$17.54	$17.87
Uinta Basin																			
-.5%, 11500 BTU	$24.64	$25.00	$25.40	$25.79	$26.20	$26.61	$27.05	$27.57	$28.11	$28.62	$29.12	$29.65	$30.16	$30.66	$31.18	$31.73	$32.27	$32.80	$33.34
Foreign Coal																			
-.7%, 12000 BTU	$50.48	$49.17	$49.72	$50.23	$50.75	$51.41	$52.10	$52.82	$53.55	$54.31	$55.12	$55.96	$56.82	$57.70	$58.63	$59.63	$60.67	$61.73	$62.77
-.8%, 11600 BTU	$47.40	$46.30	$46.91	$47.52	$48.15	$48.79	$49.48	$50.22	$51.00	$51.77	$52.55	$53.37	$54.21	$55.06	$55.95	$56.91	$57.90	$58.91	$59.90
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$36.37	$34.69	$35.07	$35.47	$35.89	$36.33	$36.82	$37.35	$37.92	$38.49	$39.03	$39.64	$40.29	$40.96	$41.68	$42.46	$43.28	$44.13	$44.95

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

ANNUAL AVERAGE SPOT
BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$37.33	$36.74	$36.17	$35.90	$35.71	$35.60	$35.48	$35.39	$35.31	$35.41	$35.38	$35.37	$35.33	$35.28	$35.24	$35.22	$35.18	$35.12	$35.08
-1.8%, 13000 BTU	$36.76	$36.26	$35.79	$35.55	$35.38	$35.28	$35.17	$35.11	$35.06	$35.11	$35.07	$35.06	$35.02	$34.97	$34.93	$34.91	$34.87	$34.82	$34.77
-2.3%, 13000 BTU	$35.91	$35.52	$35.23	$35.02	$34.88	$34.79	$34.72	$34.69	$34.68	$34.64	$34.61	$34.60	$34.56	$34.51	$34.48	$34.45	$34.41	$34.36	$34.31
Central Appalachia																			
-.7%, 12500 BTU	$54.88	$55.15	$55.54	$55.73	$54.11	$53.46	$53.08	$53.45	$53.75	$54.17	$54.60	$55.18	$55.79	$57.04	$58.37	$59.10	$59.81	$60.48	$61.12
-.7%, 13000 BTU	$58.59	$58.87	$59.29	$59.49	$57.76	$57.06	$56.65	$57.05	$57.38	$57.82	$58.29	$58.92	$59.57	$60.91	$62.35	$63.13	$63.89	$64.62	$65.30
-1.0%, 12500 BTU	$44.48	$43.15	$42.02	$41.95	$40.64	$40.06	$39.62	$39.68	$39.77	$39.90	$40.07	$40.32	$40.60	$41.32	$42.07	$42.38	$42.66	$42.93	$43.22
-1.5%, 12500 BTU	$41.23	$41.06	$40.91	$41.19	$40.07	$39.52	$39.09	$39.21	$39.32	$39.46	$39.65	$39.90	$40.19	$40.92	$41.67	$42.00	$42.29	$42.57	$42.86
Ohio																			
-4%, 12500 BTU	$32.59	$32.26	$32.00	$31.83	$31.72	$31.65	$31.60	$31.59	$31.60	$31.58	$31.56	$31.56	$31.54	$31.51	$31.50	$31.49	$31.47	$31.44	$31.41
Illinois Basin																			
-3%, 11000 BTU (IL)	$32.37	$31.95	$31.65	$31.36	$31.09	$30.84	$30.61	$30.43	$30.27	$30.07	$29.89	$29.71	$29.50	$29.29	$29.10	$28.91	$28.70	$28.49	$28.29
-3%, 11000 BTU (KY)	$34.06	$33.66	$33.37	$33.09	$32.84	$32.60	$32.38	$32.21	$32.06	$31.88	$31.71	$31.54	$31.35	$31.15	$30.96	$30.79	$30.59	$30.39	$30.20
Powder River Basin																			
-.33%, 8400 BTU	$9.95	$9.59	$9.34	$9.23	$9.13	$9.16	$9.16	$9.18	$9.19	$9.32	$9.42	$9.42	$9.40	$9.37	$9.35	$9.33	$9.30	$9.27	$9.25
-.35%, 8800 BTU	$11.78	$11.53	$11.34	$11.27	$11.22	$11.24	$11.24	$11.29	$11.36	$11.53	$11.66	$11.69	$11.70	$11.70	$11.71	$11.72	$11.73	$11.73	$11.74
Uinta Basin																			
-.5%, 11500 BTU	$22.74	$22.62	$22.54	$22.45	$22.38	$22.30	$22.24	$22.22	$22.21	$22.18	$22.15	$22.14	$22.10	$22.07	$22.04	$22.01	$21.98	$21.94	$21.90
Foreign Coal: Colombia																			
-.7%, 12000 BTU	$46.58	$44.49	$44.11	$43.72	$43.34	$43.09	$42.84	$42.58	$42.31	$42.10	$41.93	$41.78	$41.64	$41.53	$41.44	$41.38	$41.33	$41.29	$41.23
-.8%, 11600 BTU	$43.74	$41.89	$41.62	$41.36	$41.12	$40.90	$40.68	$40.48	$40.30	$40.13	$39.98	$39.85	$39.73	$39.63	$39.55	$39.48	$39.44	$39.40	$39.35
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$33.56	$31.39	$31.12	$30.87	$30.65	$30.45	$30.27	$30.11	$29.96	$29.83	$29.69	$29.59	$29.53	$29.48	$29.46	$29.46	$29.48	$29.52	$29.52
IMPLICIT PRICE DEFLATOR (GDP)	132.33	134.98	137.63	140.29	142.97	145.68	148.51	151.47	154.55	157.54	160.52	163.56	166.61	169.65	172.76	176.00	179.27	182.56	185.90
% Change	2.11%	2.00%	1.97%	1.93%	1.91%	1.90%	1.94%	1.99%	2.03%	1.93%	1.89%	1.89%	1.87%	1.83%	1.83%	1.87%	1.86%	1.83%	1.83%

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

QUARTERLY SPOT PRICE
BASE CASE

Year:			2001				2002				2003				2004				2005			
Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia																						
-1.6%, 13000 BTU	$24.38	$26.12	$32.86	$42.38	$43.91	$42.92	$35.34	$29.34	$29.09	$27.70	$28.20	$30.88	$31.57	$33.50	$41.24	$45.53	$52.70	$61.62	$56.60	$54.24	$53.91	$52.95
-1.8%, 13000 BTU	$23.59	$24.65	$31.91	$41.26	$42.81	$41.85	$34.32	$28.36	$28.09	$26.73	$27.01	$29.66	$30.41	$32.23	$40.04	$44.46	$51.30	$59.78	$55.15	$52.33	$51.52	$49.91
-2.3%, 13000 BTU	$22.55	$23.59	$29.39	$37.07	$39.40	$38.11	$31.57	$26.61	$26.66	$25.18	$25.82	$28.50	$29.34	$31.03	$39.12	$43.84	$50.32	$58.33	$52.98	$49.48	$47.94	$45.35
Central Appalachia																						
-.7%, 12500 BTU	$24.65	$28.02	$46.72	$51.11	$49.19	$41.33	$30.14	$27.67	$29.23	$29.74	$32.36	$34.02	$33.87	$36.84	$49.62	$56.75	$62.95	$65.15	$62.35	$63.07	$60.38	$62.08
-.7%, 13000 BTU	$26.17	$29.77	$49.66	$54.33	$52.31	$43.93	$32.07	$29.43	$31.12	$31.65	$34.44	$36.21	$36.07	$39.24	$52.84	$60.43	$67.05	$69.37	$66.41	$67.18	$64.33	$66.12
-1.0%, 12500 BTU	$22.92	$26.35	$43.07	$48.65	$45.89	$38.75	$28.18	$25.94	$27.24	$27.66	$29.43	$31.77	$31.93	$35.05	$47.99	$54.08	$58.30	$59.75	$57.71	$59.20	$56.23	$56.81
-1.5%, 12500 BTU	$21.04	$24.48	$34.69	$43.65	$41.15	$34.53	$24.22	$22.86	$24.53	$25.16	$26.93	$28.85	$28.96	$32.03	$44.34	$49.69	$53.05	$52.61	$53.50	$54.86	$52.78	$51.59
Ohio																						
-4%, 12500 BTU	$18.75	$19.55	$23.95	$26.85	$27.85	$27.10	$22.34	$20.15	$20.45	$19.95	$21.40	$22.95	$23.35	$24.35	$28.09	$28.78	$35.38	$40.77	$36.73	$35.18	$35.75	$35.85
Illinois Basin																						
-3%, 11000 BTU (IL)	$16.80	$17.05	$22.05	$25.35	$25.65	$25.45	$21.90	$19.80	$18.50	$18.65	$18.80	$19.55	$19.60	$20.50	$22.55	$25.07	$26.80	$30.05	$27.32	$27.22	$27.75	$27.88
-3%, 11000 BTU (KY)	$17.45	$18.45	$24.30	$31.45	$32.10	$31.85	$27.80	$22.60	$21.50	$21.45	$21.45	$21.95	$22.10	$22.85	$24.95	$28.05	$30.50	$33.20	$30.03	$29.25	$29.83	$30.15
Powder River Basin																						
-.33%, 8400 BTU	$3.40	$3.70	$6.25	$10.65	$7.05	$6.35	$4.65	$4.70	$4.65	$4.95	$5.00	$4.80	$5.25	$5.45	$5.55	$5.43	$5.00	$4.93	$5.18	$6.35	$7.72	$12.57
-.35%, 8800 BTU	$4.35	$4.55	$7.90	$12.75	$8.70	$8.00	$5.85	$5.75	$5.75	$6.05	$6.00	$5.90	$6.30	$6.65	$6.58	$6.43	$6.02	$6.02	$6.33	$7.98	$10.03	$16.00
Uinta Basin																						
-.5%, 11500 BTU	$13.30	$14.55	$19.05	$19.85	$20.55	$20.80	$18.40	$16.30	$16.45	$16.65	$16.15	$16.90	$17.15	$18.30	$22.42	$25.95	$29.42	$29.50	$28.98	$31.12	$34.82	$37.50
Foreign Coal																						
-.7%, 12000 BTU	$27.85	$30.45	$35.10	$36.90	$36.85	$32.62	$29.81	$27.54	$25.06	$28.38	$28.55	$28.04	$35.00	$42.12	$46.23	$54.39	$68.50	$67.62	$57.64	$49.06	$51.92	$41.84
-.8%, 11600 BTU	$25.63	$28.20	$32.60	$34.32	$34.31	$30.52	$27.99	$25.95	$23.57	$26.63	$26.83	$26.40	$32.86	$39.55	$43.28	$50.97	$64.08	$63.25	$53.92	$45.94	$48.57	$39.17
Petroleum Coke																						
-6%/30 HGI, 14000 BTU	$8.83	$19.78	$18.11	$14.62	$9.95	$8.24	$7.44	$5.79	$7.97	$13.08	$20.35	$14.53	$8.52	$8.71	$6.60	$6.46	$14.71	$20.46	$22.76	$13.25	$12.02	$21.98

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

QUARTERLY SPOT PRICE

BASE CASE

Year:	2006				2007				2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia																				
-1.6%, 13000 BTU	$49.63	$46.60	$44.14	$42.90	$44.00	$44.75	$46.60	$51.10	$73.12	$106.83	$135.23	$121.97	$117.50	$108.58	$92.97	$82.49	$71.84	$56.08	$49.73	$46.57
-1.8%, 13000 BTU	$46.48	$43.85	$41.92	$41.40	$43.09	$44.02	$45.83	$50.46	$72.02	$104.93	$131.75	$119.59	$115.39	$106.58	$91.07	$80.75	$70.42	$55.01	$48.94	$45.83
-2.3%, 13000 BTU	$41.76	$39.72	$38.58	$39.14	$41.73	$42.93	$44.67	$49.50	$70.37	$102.07	$126.52	$116.03	$112.22	$103.58	$88.22	$78.14	$68.29	$53.40	$47.75	$44.72
Central Appalachia																				
-.7%, 12500 BTU	$61.21	$59.39	$54.23	$48.82	$41.92	$44.73	$45.65	$53.55	$73.73	$102.73	$132.65	$124.07	$120.32	$112.05	$97.05	$90.76	$78.09	$63.98	$59.42	$57.42
-.7%, 13000 BTU	$65.20	$63.26	$57.79	$52.01	$44.66	$47.65	$48.65	$57.06	$78.58	$109.46	$141.39	$132.21	$128.24	$119.40	$103.46	$96.74	$83.25	$68.20	$63.35	$61.21
-1.0%, 12500 BTU	$55.10	$51.81	$49.69	$46.23	$39.55	$42.53	$43.65	$51.60	$70.80	$99.55	$129.65	$121.17	$117.47	$108.96	$93.72	$87.16	$74.19	$59.78	$54.92	$52.62
-1.5%, 12500 BTU	$48.97	$46.25	$44.09	$42.62	$35.52	$39.22	$40.17	$47.98	$65.05	$92.03	$111.25	$104.73	$102.12	$94.76	$80.72	$75.00	$62.77	$49.58	$45.03	$43.93
Ohio																				
-4%, 12500 BTU	$34.63	$32.63	$30.67	$32.24	$35.45	$37.43	$38.63	$45.23	$65.68	$80.68	$90.76	$87.44	$86.32	$80.97	$73.76	$71.86	$61.37	$48.21	$43.31	$40.52
Illinois Basin																				
-3%, 11000 BTU (IL)	$27.27	$26.53	$26.63	$27.60	$26.85	$26.53	$26.93	$27.73	$31.72	$48.45	$60.67	$62.15	$62.03	$57.87	$52.52	$45.52	$41.00	$37.82	$37.17	$36.48
-3%, 11000 BTU (KY)	$29.37	$28.57	$28.72	$29.58	$28.77	$28.52	$28.77	$29.60	$33.63	$50.43	$62.50	$64.02	$63.85	$59.73	$54.28	$47.30	$42.82	$39.68	$38.93	$38.27
Powder River Basin																				
-.33%, 8400 BTU	$14.20	$10.63	$8.20	$7.63	$7.18	$7.48	$8.92	$9.85	$11.57	$11.53	$11.62	$12.37	$13.12	$12.50	$11.48	$10.87	$10.85	$10.70	$11.50	$11.28
-.35%, 8800 BTU	$17.68	$13.62	$10.18	$9.47	$8.80	$8.93	$10.47	$11.20	$13.73	$13.92	$13.52	$13.97	$14.52	$13.92	$12.82	$12.33	$12.28	$12.12	$12.83	$12.75
Uinta Basin																				
-.5%, 11500 BTU	$38.45	$37.62	$35.83	$35.13	$33.75	$32.50	$27.02	$26.43	$34.37	$50.63	$75.12	$78.98	$73.72	$60.23	$47.93	$36.57	$30.93	$26.42	$25.63	$25.32
Foreign Coal																				
-.7%, 12000 BTU	$48.83	$52.74	$50.93	$49.61	$51.13	$52.48	$59.37	$85.13	$107.74	$124.32	$144.00	$125.74	$123.07	$117.18	$112.62	$107.20	$98.65	$82.68	$68.88	$56.12
-.8%, 11600 BTU	$45.68	$49.24	$47.65	$46.32	$47.70	$48.95	$55.37	$79.38	$100.50	$115.97	$134.27	$117.25	$114.77	$109.31	$105.08	$100.05	$92.13	$77.25	$64.40	$52.48
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$24.99	$36.75	$39.32	$37.98	$44.03	$47.68	$44.98	$42.90	$53.01	$66.04	$76.59	$70.85	$68.94	$56.49	$52.85	$56.33	$57.37	$52.74	$47.83	$42.13

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

	Cell
ANNUAL AVERAGE CONTRACT PRICES - NOMINAL DOLLARS PE	A14
ANNUAL AVERAGE CONTRACT PRICES - REAL 2008 DOLLARS P	A67
QUARTERLY CONTRACT PRICES - NOMINAL DOLLARS PER TON	A121

ANNUAL AVERAGE CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$102.89	$89.58	$50.24	$41.98	$41.78	$41.99	$42.33	$42.89	$43.52	$44.22	$44.97	$45.80	$46.69
-1.8%, 13000 BTU	$100.86	$87.94	$49.43	$41.31	$41.20	$41.50	$41.91	$42.48	$43.12	$43.84	$44.60	$45.44	$46.32
-2.3%, 13000 BTU	$97.81	$85.48	$48.21	$40.31	$40.34	$40.76	$41.27	$41.87	$42.53	$43.26	$44.06	$44.91	$45.76
Central Appalachia													
-.7%, 12500 BTU	$105.62	$96.98	$61.76	$60.17	$62.31	$63.88	$65.10	$65.67	$65.61	$66.39	$67.69	$69.50	$71.35
-.7%, 13000 BTU	$112.58	$103.39	$65.89	$64.25	$66.52	$68.19	$69.49	$70.10	$70.03	$70.87	$72.25	$74.19	$76.17
-1.0%, 12500 BTU	$101.17	$90.77	$55.18	$49.47	$49.33	$49.10	$49.11	$49.37	$49.19	$49.61	$50.35	$51.47	$52.64
-1.5%, 12500 BTU	$87.03	$79.85	$47.59	$45.54	$46.51	$47.33	$48.05	$48.57	$48.51	$48.95	$49.72	$50.87	$52.06
Ohio													
-4%, 12500 BTU	$79.10	$69.43	$43.19	$36.58	$36.62	$37.02	$37.51	$38.07	$38.69	$39.37	$40.11	$40.91	$41.71
Illinois Basin													
-3%, 11000 BTU (IL)	$51.42	$51.57	$37.63	$36.08	$36.32	$36.62	$36.99	$37.37	$37.77	$38.21	$38.70	$39.25	$39.79
-3%, 11000 BTU (KY)	$53.56	$53.93	$39.50	$37.96	$38.24	$38.60	$39.02	$39.45	$39.91	$40.41	$40.97	$41.57	$42.18
Powder River Basin													
-.33%, 8400 BTU	$12.48	$11.88	$11.38	$11.25	$11.00	$10.90	$10.90	$11.01	$11.17	$11.41	$11.64	$11.92	$12.24
-.35%, 8800 BTU	$14.22	$13.61	$13.08	$13.25	$13.15	$13.18	$13.28	$13.48	$13.72	$14.00	$14.32	$14.71	$15.15
Uinta Basin													
-.5%, 11500 BTU	$54.94	$48.85	$26.99	$25.98	$25.64	$26.02	$26.43	$26.85	$27.27	$27.72	$28.22	$28.76	$29.30
Foreign Coal													
-.7%, 12000 BTU	$106.24	$79.42	$66.79	$53.80	$51.41	$51.02	$51.56	$52.12	$52.73	$53.43	$54.16	$54.91	$55.69
-.8%, 11600 BTU	$109.29	$97.37	$62.49	$50.46	$48.36	$48.11	$48.74	$49.38	$50.04	$50.74	$51.48	$52.26	$53.06
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$64.74	$56.44	$45.98	$39.40	$36.66	$36.00	$36.40	$36.83	$37.28	$37.76	$38.30	$38.86	$39.44

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE CONTRACT PRICES - REAL 2008 DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$102.89	$87.76	$48.30	$39.56	$38.55	$37.99	$37.56	$37.33	$37.17	$37.07	$36.97	$36.92	$36.89
-1.8%, 13000 BTU	$100.86	$86.15	$47.52	$38.93	$38.02	$37.54	$37.18	$36.97	$36.83	$36.75	$36.67	$36.63	$36.60
-2.3%, 13000 BTU	$97.81	$83.74	$46.35	$37.99	$37.22	$36.88	$36.62	$36.44	$36.32	$36.26	$36.22	$36.20	$36.16
Central Appalachia													
-.7%, 12500 BTU	$105.62	$95.00	$59.38	$56.69	$57.49	$57.79	$57.76	$57.16	$56.03	$55.65	$55.65	$56.03	$56.37
-.7%, 13000 BTU	$112.58	$101.28	$63.35	$60.54	$61.38	$61.69	$61.65	$61.02	$59.81	$59.40	$59.41	$59.81	$60.18
-1.0%, 12500 BTU	$101.17	$88.92	$53.05	$46.61	$45.52	$44.42	$43.57	$42.97	$42.01	$41.58	$41.40	$41.49	$41.59
-1.5%, 12500 BTU	$87.03	$78.23	$45.76	$42.91	$42.92	$42.82	$42.63	$42.28	$41.43	$41.03	$40.88	$41.01	$41.13
Ohio													
-4%, 12500 BTU	$79.10	$68.01	$41.52	$34.47	$33.79	$33.49	$33.28	$33.13	$33.04	$33.00	$32.98	$32.98	$32.95
Illinois Basin													
-3%, 11000 BTU (IL)	$51.42	$50.52	$36.18	$33.99	$33.51	$33.13	$32.82	$32.52	$32.26	$32.02	$31.82	$31.64	$31.44
-3%, 11000 BTU (KY)	$53.56	$52.83	$37.97	$35.77	$35.29	$34.92	$34.62	$34.34	$34.09	$33.87	$33.68	$33.51	$33.32
Powder River Basin													
-.33%, 8400 BTU	$12.48	$11.64	$10.94	$10.60	$10.15	$9.86	$9.67	$9.58	$9.54	$9.56	$9.57	$9.61	$9.67
-.35%, 8800 BTU	$14.22	$13.33	$12.58	$12.49	$12.13	$11.92	$11.78	$11.73	$11.72	$11.74	$11.77	$11.85	$11.97
Uinta Basin													
-.5%, 11500 BTU	$54.94	$47.85	$25.95	$24.48	$23.65	$23.54	$23.45	$23.37	$23.29	$23.24	$23.20	$23.19	$23.15
Foreign Coal: Colombia													
-.7%, 12000 BTU	$106.24	$77.80	$64.21	$50.69	$47.44	$46.16	$45.75	$45.36	$45.04	$44.79	$44.53	$44.26	$44.00
-.8%, 11600 BTU	$109.29	$95.39	$60.07	$47.55	$44.62	$43.52	$43.24	$42.98	$42.74	$42.53	$42.33	$42.13	$41.92
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$64.74	$55.29	$44.20	$37.13	$33.83	$32.57	$32.30	$32.05	$31.84	$31.65	$31.49	$31.33	$31.16

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

QUARTERLY CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$72.06	$108.68	$117.78	$113.06	$108.62	$94.96	$83.07	$71.68	$62.31	$50.44	$46.95	$41.25
-1.8%, 13000 BTU	$70.47	$106.55	$115.46	$110.95	$106.61	$93.20	$81.54	$70.41	$61.26	$49.62	$46.22	$40.61
-2.3%, 13000 BTU	$68.09	$103.36	$111.99	$107.79	$103.60	$90.57	$79.25	$68.51	$59.68	$48.39	$45.11	$39.65
Central Appalachia												
-.7%, 12500 BTU	$75.06	$101.89	$127.37	$118.15	$113.67	$102.43	$89.46	$82.34	$70.32	$59.22	$58.69	$58.81
-.7%, 13000 BTU	$80.00	$108.61	$135.77	$125.94	$121.18	$109.20	$95.39	$87.81	$75.01	$63.18	$62.62	$62.76
-1.0%, 12500 BTU	$70.81	$97.62	$121.38	$114.88	$105.44	$96.57	$85.90	$75.19	$63.36	$55.92	$51.56	$49.89
-1.5%, 12500 BTU	$60.95	$84.22	$103.99	$98.94	$94.23	$83.99	$75.10	$66.10	$53.80	$47.77	$44.38	$44.41
Ohio												
-4%, 12500 BTU	$62.05	$81.22	$89.24	$83.89	$78.73	$72.37	$64.44	$62.17	$54.05	$43.88	$40.93	$36.68
Illinois Basin												
-3%, 11000 BTU (IL)	$34.05	$51.36	$59.36	$60.92	$58.58	$54.64	$50.12	$42.93	$38.48	$36.27	$35.38	$35.21
-3%, 11000 BTU (KY)	$35.90	$53.32	$61.65	$63.38	$61.08	$57.10	$52.49	$45.04	$40.42	$38.12	$37.20	$37.05
Powder River Basin												
-.33%, 8400 BTU	$12.11	$12.65	$12.61	$12.56	$12.84	$12.25	$11.41	$11.01	$11.00	$10.98	$10.97	$10.90
-.35%, 8800 BTU	$14.06	$14.36	$14.26	$14.22	$14.59	$14.01	$13.11	$12.72	$12.75	$12.78	$12.82	$12.82
Uinta Basin												
-.5%, 11500 BTU	$33.12	$49.54	$68.80	$68.29	$64.28	$52.41	$44.81	$33.89	$27.56	$26.00	$25.34	$25.09
Foreign Coal												
-.7%, 12000 BTU	$88.57	$117.98	$115.91	$102.50	$89.16	$81.26	$76.83	$70.43	$64.61	$60.19	$57.18	$54.44
-.8%, 11600 BTU	$82.66	$114.70	$128.11	$111.67	$104.12	$100.11	$96.22	$89.05	$78.09	$66.65	$54.59	$50.14
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$56.16	$64.14	$72.60	$66.06	$59.46	$55.04	$55.49	$55.77	$55.53	$49.11	$43.48	$40.44

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE CONTRA

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$47.63	$48.49	$49.36	$50.21	$51.07	$51.97	$52.89	$53.79	$54.71	$55.63
-1.8%, 13000 BTU	$47.21	$48.07	$48.93	$49.77	$50.63	$51.52	$52.43	$53.32	$54.23	$55.15
-2.3%, 13000 BTU	$46.59	$47.44	$48.28	$49.12	$49.96	$50.84	$51.74	$52.62	$53.52	$54.42
Central Appalachia										
-.7%, 12500 BTU	$73.32	$75.40	$77.80	$80.58	$83.79	$86.85	$89.54	$92.24	$94.97	$97.76
-.7%, 13000 BTU	$78.27	$80.51	$83.07	$86.06	$89.49	$92.77	$95.65	$98.55	$101.47	$104.46
-1.0%, 12500 BTU	$53.87	$55.18	$56.68	$58.46	$60.49	$62.38	$63.98	$65.59	$67.24	$68.94
-1.5%, 12500 BTU	$53.29	$54.61	$56.11	$57.88	$59.91	$61.80	$63.41	$65.02	$66.66	$68.35
Ohio										
-4%, 12500 BTU	$42.48	$43.27	$44.06	$44.85	$45.64	$46.46	$47.31	$48.14	$48.98	$49.82
Illinois Basin										
-3%, 11000 BTU (IL)	$40.30	$40.81	$41.30	$41.77	$42.25	$42.74	$43.24	$43.72	$44.20	$44.69
-3%, 11000 BTU (KY)	$42.75	$43.31	$43.87	$44.41	$44.95	$45.51	$46.07	$46.62	$47.17	$47.72
Powder River Basin										
-.33%, 8400 BTU	$12.61	$12.91	$13.14	$13.34	$13.55	$13.77	$13.99	$14.21	$14.43	$14.65
-.35%, 8800 BTU	$15.61	$16.01	$16.33	$16.64	$16.96	$17.29	$17.62	$17.96	$18.30	$18.67
Uinta Basin										
-.5%, 11500 BTU	$29.83	$30.36	$30.89	$31.41	$31.94	$32.49	$33.05	$33.60	$34.16	$34.73
Foreign Coal										
-.7%, 12000 BTU	$56.50	$57.35	$58.23	$59.14	$60.08	$61.09	$62.14	$63.22	$64.30	$65.36
-.8%, 11600 BTU	$53.87	$54.69	$55.55	$56.43	$57.34	$58.29	$59.30	$60.33	$61.36	$62.38
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$40.02	$40.62	$41.28	$41.96	$42.69	$43.47	$44.30	$45.15	$46.01	$46.85

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE CONTRA

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	**$36.92**	**$36.89**	**$36.85**	**$36.80**	**$36.76**	**$36.73**	**$36.70**	**$36.64**	**$36.59**	**$36.54**
-1.8%, 13000 BTU	**$36.60**	**$36.57**	**$36.53**	**$36.48**	**$36.44**	**$36.42**	**$36.38**	**$36.32**	**$36.27**	**$36.22**
-2.3%, 13000 BTU	**$36.11**	**$36.09**	**$36.05**	**$36.00**	**$35.96**	**$35.94**	**$35.90**	**$35.84**	**$35.79**	**$35.75**
Central Appalachia										
-.7%, 12500 BTU	**$56.83**	**$57.36**	**$58.08**	**$59.06**	**$60.31**	**$61.39**	**$62.12**	**$62.83**	**$63.52**	**$64.21**
-.7%, 13000 BTU	**$60.67**	**$61.24**	**$62.02**	**$63.07**	**$64.41**	**$65.57**	**$66.36**	**$67.12**	**$67.87**	**$68.61**
-1.0%, 12500 BTU	**$41.75**	**$41.98**	**$42.32**	**$42.84**	**$43.54**	**$44.09**	**$44.39**	**$44.68**	**$44.97**	**$45.28**
-1.5%, 12500 BTU	**$41.31**	**$41.54**	**$41.89**	**$42.42**	**$43.12**	**$43.68**	**$44.00**	**$44.29**	**$44.59**	**$44.90**
Ohio										
-4%, 12500 BTU	**$32.93**	**$32.92**	**$32.90**	**$32.87**	**$32.85**	**$32.84**	**$32.82**	**$32.79**	**$32.76**	**$32.73**
Illinois Basin										
-3%, 11000 BTU (IL)	**$31.24**	**$31.04**	**$30.83**	**$30.62**	**$30.41**	**$30.21**	**$30.00**	**$29.78**	**$29.57**	**$29.35**
-3%, 11000 BTU (KY)	**$33.13**	**$32.95**	**$32.75**	**$32.55**	**$32.35**	**$32.17**	**$31.97**	**$31.76**	**$31.55**	**$31.35**
Powder River Basin										
-.33%, 8400 BTU	**$9.77**	**$9.82**	**$9.81**	**$9.78**	**$9.75**	**$9.73**	**$9.71**	**$9.68**	**$9.65**	**$9.62**
-.35%, 8800 BTU	**$12.10**	**$12.18**	**$12.20**	**$12.20**	**$12.21**	**$12.22**	**$12.23**	**$12.23**	**$12.24**	**$12.26**
Uinta Basin										
-.5%, 11500 BTU	**$23.12**	**$23.09**	**$23.06**	**$23.02**	**$22.99**	**$22.96**	**$22.93**	**$22.89**	**$22.85**	**$22.81**
Foreign Coal: Colombia										
-.7%, 12000 BTU	**$43.80**	**$43.63**	**$43.48**	**$43.34**	**$43.25**	**$43.18**	**$43.11**	**$43.06**	**$43.01**	**$42.93**
-.8%, 11600 BTU	**$41.75**	**$41.61**	**$41.47**	**$41.36**	**$41.27**	**$41.20**	**$41.14**	**$41.09**	**$41.04**	**$40.97**
Petroleum Coke										
-6%/30 HGI, 14000 BTU	**$31.02**	**$30.90**	**$30.82**	**$30.76**	**$30.73**	**$30.73**	**$30.74**	**$30.76**	**$30.78**	**$30.77**

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

HIGH CASE

August 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$130.75	$186.80	$166.74	$137.86	$108.77	$96.29	$87.55	$82.29	$82.01	$82.72	$83.69	$84.86
-1.8%, 13000 BTU	$45.85	$128.06	$183.10	$163.80	$135.49	$107.12	$95.01	$86.64	$81.48	$81.25	$81.97	$82.97	$84.19
-2.3%, 13000 BTU	$44.71	$124.03	$177.69	$159.31	$131.94	$104.63	$93.10	$85.28	$80.27	$80.11	$80.84	$81.90	$83.19
Central Appalachia													
-.7%, 12500 BTU	$46.46	$128.57	$185.30	$163.85	$131.26	$102.12	$92.96	$94.89	$96.99	$99.23	$101.63	$104.07	$106.65
-.7%, 13000 BTU	$49.50	$137.01	$197.50	$174.73	$140.22	$109.03	$99.24	$101.29	$103.53	$105.92	$108.48	$111.08	$113.84
-1.0%, 12500 BTU	$44.33	$125.00	$179.62	$152.84	$110.84	$82.77	$72.73	$71.79	$73.02	$74.52	$76.16	$77.67	$79.18
-1.5%, 12500 BTU	$40.72	$110.72	$155.49	$127.41	$100.45	$76.72	$69.21	$69.89	$71.70	$73.47	$75.13	$76.64	$78.23
Ohio													
-4%, 12500 BTU	$39.19	$96.15	$146.94	$143.94	$119.69	$94.96	$84.53	$77.47	$72.96	$72.84	$73.54	$74.54	$75.75
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$57.55	$83.28	$84.89	$71.53	$70.82	$70.19	$69.75	$69.30	$68.88	$68.45	$68.06	$67.80
-3%, 11000 BTU (KY)	$28.91	$59.65	$86.08	$88.92	$75.29	$74.55	$73.96	$73.58	$73.17	$72.79	$72.40	$72.06	$71.84
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.43	$15.78	$14.43	$13.89	$14.26	$14.55	$14.99	$15.46	$15.95	$16.66	$17.34	$18.08
-.35%, 8800 BTU	$9.85	$14.44	$17.18	$15.84	$16.19	$16.88	$17.49	$18.20	$18.88	$19.59	$20.45	$21.28	$22.25
Uinta Basin													
-.5%, 11500 BTU	$29.93	$65.15	$101.65	$92.01	$81.10	$74.45	$69.14	$64.37	$59.71	$55.52	$56.49	$57.50	$58.55
Foreign Coal													
-.7%, 12000 BTU	$62.03	$148.93	$202.88	$193.86	$125.62	$86.67	$74.99	$75.37	$76.09	$79.48	$81.92	$84.00	$84.96
-.8%, 11600 BTU	$57.85	$138.90	$189.28	$181.16	$117.62	$81.38	$70.61	$71.10	$71.99	$75.41	$77.75	$79.77	$80.78
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$78.25	$103.85	$126.98	$93.97	$62.44	$52.90	$53.16	$53.74	$56.21	$57.90	$59.36	$60.08

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

HIGH CASE

August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$130.75	$182.99	$160.30	$129.90	$100.37	$87.11	$77.68	$71.63	$70.05	$69.33	$68.81	$68.41
-1.8%, 13000 BTU	$46.79	$128.06	$179.37	$157.48	$127.67	$98.84	$85.96	$76.87	$70.92	$69.40	$68.70	$68.22	$67.87
-2.3%, 13000 BTU	$45.62	$124.03	$174.07	$153.16	$124.32	$96.55	$84.22	$75.66	$69.87	$68.42	$67.76	$67.34	$67.06
Central Appalachia													
-.7%, 12500 BTU	$47.41	$128.57	$181.52	$157.52	$123.68	$94.23	$84.10	$84.19	$84.42	$84.75	$85.18	$85.56	$85.98
-.7%, 13000 BTU	$50.52	$137.01	$193.47	$167.98	$132.12	$100.60	$89.78	$89.87	$90.11	$90.46	$90.93	$91.34	$91.77
-1.0%, 12500 BTU	$45.24	$125.00	$175.96	$146.94	$104.44	$76.38	$65.80	$63.69	$63.56	$63.65	$63.84	$63.87	$63.83
-1.5%, 12500 BTU	$41.55	$110.72	$152.32	$122.49	$94.65	$70.79	$62.61	$62.01	$62.40	$62.75	$62.97	$63.01	$63.07
Ohio													
-4%, 12500 BTU	$39.99	$96.15	$143.94	$138.38	$112.78	$87.63	$76.47	$68.73	$63.50	$62.21	$61.64	$61.29	$61.06
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$57.55	$81.58	$81.61	$67.40	$65.35	$63.49	$61.89	$60.32	$58.83	$57.37	$55.96	$54.66
-3%, 11000 BTU (KY)	$29.50	$59.65	$84.32	$85.49	$70.94	$68.79	$66.91	$65.28	$63.69	$62.17	$60.68	$59.24	$57.91
Powder River Basin													
-.33%, 8400 BTU	$8.53	$12.43	$15.45	$13.87	$13.08	$13.16	$13.16	$13.30	$13.46	$13.62	$13.97	$14.26	$14.58
-.35%, 8800 BTU	$10.05	$14.44	$16.83	$15.23	$15.26	$15.58	$15.82	$16.15	$16.43	$16.73	$17.14	$17.50	$17.94
Uinta Basin													
-.5%, 11500 BTU	$30.54	$65.15	$99.58	$88.46	$76.42	$68.70	$62.55	$57.11	$51.97	$47.42	$47.35	$47.28	$47.20
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$148.93	$198.75	$186.38	$118.37	$79.97	$67.84	$66.87	$66.23	$67.88	$68.66	$69.07	$68.49
-.8%, 11600 BTU	$59.03	$138.90	$185.42	$174.17	$110.83	$75.09	$63.88	$63.08	$62.66	$64.41	$65.17	$65.59	$65.12
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$78.25	$101.73	$122.08	$88.54	$57.61	$47.86	$47.16	$46.77	$48.01	$48.53	$48.81	$48.43

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
HIGH CASE
August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$73.12	$106.83	$168.45	$174.60	$183.25	$186.15	$190.45	$187.35	$182.45	$175.00	$161.15	$148.35
-1.8%, 13000 BTU	$72.02	$104.93	$164.11	$171.20	$179.95	$182.72	$186.56	$183.40	$178.84	$171.65	$158.58	$145.99
-2.3%, 13000 BTU	$70.37	$102.07	$157.59	$166.11	$175.01	$177.58	$180.72	$177.47	$173.43	$166.63	$154.72	$142.46
Central Appalachia												
-.7%, 12500 BTU	$73.73	$102.73	$164.85	$172.95	$181.44	$185.00	$189.40	$185.35	$179.20	$171.10	$159.15	$145.95
-.7%, 13000 BTU	$78.58	$109.46	$175.71	$184.31	$193.39	$197.15	$201.91	$197.56	$191.04	$182.37	$169.70	$155.59
-1.0%, 12500 BTU	$70.80	$99.55	$161.12	$168.91	$177.14	$179.91	$182.89	$178.00	$170.25	$159.87	$147.10	$133.75
-1.5%, 12500 BTU	$65.05	$92.03	$138.26	$146.00	$153.99	$156.46	$157.52	$153.15	$144.05	$132.59	$120.62	$111.68
Ohio												
-4%, 12500 BTU	$65.68	$80.68	$113.06	$125.17	$134.62	$138.82	$151.10	$163.22	$155.85	$150.44	$140.35	$129.10
Illinois Basin												
-3%, 11000 BTU (IL)	$31.72	$48.45	$72.55	$77.50	$80.20	$82.50	$85.75	$84.65	$85.00	$84.40	$86.00	$84.15
-3%, 11000 BTU (KY)	$33.63	$50.43	$74.72	$79.83	$82.55	$85.16	$88.63	$87.97	$88.77	$88.57	$90.09	$88.26
Powder River Basin												
-.33%, 8400 BTU	$11.57	$11.53	$13.10	$13.50	$14.85	$15.90	$16.35	$16.00	$15.50	$14.40	$14.00	$13.80
-.35%, 8800 BTU	$13.73	$13.92	$15.00	$15.10	$16.25	$17.32	$17.68	$17.47	$16.93	$15.82	$15.33	$15.27
Uinta Basin												
-.5%, 11500 BTU	$34.37	$50.63	$84.25	$91.35	$98.65	$100.45	$104.55	$102.95	$98.30	$94.45	$89.70	$85.60
Foreign Coal												
-.7%, 12000 BTU	$107.74	$124.32	$178.95	$175.28	$185.59	$193.47	$219.78	$218.91	$226.37	$221.10	$184.51	$142.64
-.8%, 11600 BTU	$100.50	$115.97	$166.86	$163.45	$173.07	$180.48	$205.08	$204.32	$211.43	$206.58	$172.49	$133.40
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$53.01	$66.04	$95.18	$98.76	$103.96	$93.27	$103.15	$115.03	$131.66	$141.03	$128.13	$107.09

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
HIGH CASE
August 2008

ANNUAL AVERAGE SPOT F

HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$86.22	$88.06	$89.57	$91.14	$92.74	$94.36	$96.04	$97.82	$99.65	$101.52	$103.45
-1.8%, 13000 BTU	$85.60	$87.30	$88.79	$90.35	$91.93	$93.54	$95.20	$96.97	$98.78	$100.63	$102.55
-2.3%, 13000 BTU	$84.68	$86.15	$87.62	$89.16	$90.72	$92.31	$93.95	$95.69	$97.48	$99.31	$101.20
Central Appalachia											
-.7%, 12500 BTU	$109.36	$112.00	$114.66	$117.39	$120.15	$122.93	$125.78	$128.75	$131.78	$134.84	$137.96
-.7%, 13000 BTU	$116.74	$119.56	$122.42	$125.34	$128.30	$131.29	$134.34	$137.53	$140.77	$144.05	$147.41
-1.0%, 12500 BTU	$80.91	$82.50	$84.16	$85.77	$87.44	$89.07	$90.65	$92.33	$94.00	$95.71	$97.57
-1.5%, 12500 BTU	$79.99	$81.59	$83.27	$84.89	$86.57	$88.20	$89.79	$91.49	$93.17	$94.89	$96.74
Ohio											
-4%, 12500 BTU	$77.15	$78.52	$79.90	$81.34	$82.81	$84.29	$85.83	$87.47	$89.15	$90.86	$92.63
Illinois Basin											
-3%, 11000 BTU (IL)	$67.57	$67.22	$66.84	$66.44	$65.96	$65.43	$64.90	$64.40	$63.83	$63.20	$62.57
-3%, 11000 BTU (KY)	$71.64	$71.33	$70.97	$70.61	$70.16	$69.65	$69.14	$68.66	$68.10	$67.50	$66.88
Powder River Basin											
-.33%, 8400 BTU	$18.87	$19.71	$20.52	$21.48	$22.40	$23.34	$24.33	$25.37	$26.46	$27.59	$28.78
-.35%, 8800 BTU	$23.33	$24.40	$25.40	$26.65	$27.87	$29.15	$30.47	$31.88	$33.35	$34.90	$36.53
Uinta Basin											
-.5%, 11500 BTU	$59.65	$60.71	$61.76	$62.84	$63.91	$64.98	$66.06	$67.20	$68.34	$69.49	$70.65
Foreign Coal											
-.7%, 12000 BTU	$86.07	$87.04	$88.07	$88.88	$89.70	$89.51	$89.30	$90.14	$91.05	$92.05	$93.07
-.8%, 11600 BTU	$81.98	$82.97	$83.96	$84.77	$85.57	$85.42	$85.22	$86.02	$86.89	$87.85	$88.81
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$60.96	$61.68	$62.35	$62.96	$63.59	$63.54	$63.48	$64.18	$64.94	$65.80	$66.64

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
HIGH CASE
August 2008

ANNUAL AVERAGE SPOT F

HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$68.12	$68.26	$68.14	$68.05	$67.97	$67.92	$67.88	$67.87	$67.88	$67.90	$67.95
-1.8%, 13000 BTU	$67.64	$67.66	$67.55	$67.45	$67.38	$67.33	$67.29	$67.28	$67.28	$67.31	$67.36
-2.3%, 13000 BTU	$66.91	$66.77	$66.66	$66.57	$66.49	$66.44	$66.41	$66.39	$66.40	$66.43	$66.47
Central Appalachia											
-.7%, 12500 BTU	$86.41	$86.81	$87.23	$87.64	$88.06	$88.48	$88.91	$89.33	$89.76	$90.19	$90.62
-.7%, 13000 BTU	$92.23	$92.67	$93.13	$93.58	$94.04	$94.50	$94.96	$95.42	$95.88	$96.35	$96.82
-1.0%, 12500 BTU	$63.93	$63.95	$64.02	$64.04	$64.09	$64.11	$64.07	$64.06	$64.02	$64.02	$64.09
-1.5%, 12500 BTU	$63.20	$63.24	$63.35	$63.38	$63.45	$63.49	$63.47	$63.48	$63.46	$63.47	$63.54
Ohio											
-4%, 12500 BTU	$60.95	$60.86	$60.79	$60.73	$60.69	$60.67	$60.67	$60.69	$60.72	$60.77	$60.85
Illinois Basin											
-3%, 11000 BTU (IL)	$53.39	$52.11	$50.84	$49.60	$48.34	$47.09	$45.87	$44.68	$43.47	$42.27	$41.10
-3%, 11000 BTU (KY)	$56.60	$55.29	$53.99	$52.72	$51.42	$50.13	$48.87	$47.64	$46.39	$45.15	$43.93
Powder River Basin											
-.33%, 8400 BTU	$14.91	$15.28	$15.61	$16.04	$16.41	$16.80	$17.19	$17.60	$18.02	$18.45	$18.90
-.35%, 8800 BTU	$18.43	$18.91	$19.32	$19.90	$20.43	$20.98	$21.54	$22.12	$22.72	$23.34	$24.00
Uinta Basin											
-.5%, 11500 BTU	$47.13	$47.06	$46.99	$46.91	$46.84	$46.77	$46.70	$46.62	$46.55	$46.48	$46.41
Foreign Coal: Colombia											
-.7%, 12000 BTU	$68.01	$67.47	$66.99	$66.36	$65.74	$64.43	$63.12	$62.54	$62.02	$61.57	$61.13
-.8%, 11600 BTU	$64.77	$64.31	$63.87	$63.29	$62.72	$61.48	$60.24	$59.68	$59.18	$58.76	$58.34
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$48.16	$47.81	$47.43	$47.00	$46.61	$45.74	$44.87	$44.53	$44.24	$44.01	$43.77

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$95.68	$49.48	$30.24	$29.04	$28.91	$28.59	$28.21	$27.99	$27.80	$27.64	$28.83	$28.62
-1.8%, 13000 BTU	$45.85	$93.75	$48.52	$29.70	$28.54	$28.47	$28.21	$27.92	$27.71	$27.54	$27.39	$28.58	$28.40
-2.3%, 13000 BTU	$44.71	$90.87	$47.09	$28.89	$27.80	$27.81	$27.64	$27.48	$27.30	$27.15	$27.01	$28.21	$28.06
Central Appalachia													
-.7%, 12500 BTU	$46.46	$93.12	$50.49	$40.76	$39.64	$39.97	$40.54	$41.12	$41.58	$42.11	$42.69	$43.33	$44.01
-.7%, 13000 BTU	$49.50	$99.23	$53.81	$43.47	$42.34	$42.67	$43.28	$43.89	$44.38	$44.95	$45.57	$46.25	$46.97
-1.0%, 12500 BTU	$44.33	$90.53	$48.94	$38.02	$33.47	$32.40	$31.72	$31.11	$31.30	$31.63	$31.99	$32.34	$32.67
-1.5%, 12500 BTU	$40.72	$80.19	$42.37	$31.70	$30.34	$30.03	$30.18	$30.28	$30.74	$31.18	$31.56	$31.91	$32.28
Ohio													
-4%, 12500 BTU	$39.19	$71.60	$38.49	$26.10	$25.21	$25.24	$25.10	$24.96	$24.81	$24.69	$24.57	$25.68	$25.55
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$46.30	$38.53	$29.13	$25.54	$25.47	$25.42	$25.45	$25.48	$25.52	$25.57	$25.63	$25.75
-3%, 11000 BTU (KY)	$28.91	$48.07	$39.81	$30.51	$26.88	$26.81	$26.79	$26.85	$26.90	$26.97	$27.04	$27.14	$27.28
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.60	$8.68	$8.71	$9.05	$8.82	$8.59	$8.42	$8.32	$8.24	$8.27	$8.30	$8.35
-.35%, 8800 BTU	$9.85	$12.51	$10.06	$10.29	$10.55	$10.44	$10.32	$10.23	$10.16	$10.13	$10.15	$10.19	$10.28
Uinta Basin													
-.5%, 11500 BTU	$29.93	$54.25	$40.67	$21.69	$19.51	$18.97	$18.46	$17.96	$17.49	$17.03	$16.60	$16.18	$15.78
Foreign Coal													
-.7%, 12000 BTU	$62.03	$107.87	$55.28	$48.23	$37.94	$33.92	$32.70	$32.66	$32.62	$33.73	$34.41	$34.97	$35.06
-.8%, 11600 BTU	$57.85	$100.60	$51.57	$45.07	$35.52	$31.85	$30.79	$30.81	$30.86	$32.00	$32.66	$33.21	$33.33
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$57.93	$28.18	$31.56	$28.38	$24.44	$23.07	$23.04	$23.04	$23.85	$24.32	$24.72	$24.79

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
LOW CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$95.68	$48.47	$29.07	$27.37	$26.68	$25.87	$25.03	$24.36	$23.74	$23.17	$23.70	$23.07
-1.8%, 13000 BTU	$46.79	$93.75	$47.54	$28.56	$26.90	$26.27	$25.52	$24.77	$24.12	$23.52	$22.96	$23.50	$22.89
-2.3%, 13000 BTU	$45.62	$90.87	$46.13	$27.77	$26.19	$25.66	$25.01	$24.38	$23.76	$23.19	$22.64	$23.19	$22.62
Central Appalachia													
-.7%, 12500 BTU	$47.41	$93.12	$49.46	$39.19	$37.35	$36.88	$36.67	$36.48	$36.19	$35.97	$35.78	$35.63	$35.48
-.7%, 13000 BTU	$50.52	$99.23	$52.72	$41.79	$39.90	$39.37	$39.15	$38.94	$38.63	$38.39	$38.20	$38.03	$37.87
-1.0%, 12500 BTU	$45.24	$90.53	$47.94	$36.56	$31.54	$29.89	$28.69	$27.60	$27.25	$27.01	$26.82	$26.59	$26.34
-1.5%, 12500 BTU	$41.55	$80.19	$41.50	$30.47	$28.58	$27.71	$27.30	$26.87	$26.75	$26.63	$26.45	$26.24	$26.02
Ohio													
-4%, 12500 BTU	$39.99	$71.60	$37.71	$25.09	$23.76	$23.29	$22.71	$22.15	$21.60	$21.09	$20.60	$21.11	$20.59
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$46.30	$37.74	$28.00	$24.07	$23.50	$23.00	$22.58	$22.18	$21.80	$21.43	$21.08	$20.76
-3%, 11000 BTU (KY)	$29.50	$48.07	$39.00	$29.33	$25.33	$24.73	$24.24	$23.82	$23.42	$23.04	$22.67	$22.31	$21.99
Powder River Basin													
-.33%, 8400 BTU	$8.53	$10.60	$8.50	$8.38	$8.52	$8.14	$7.77	$7.47	$7.24	$7.04	$6.93	$6.83	$6.73
-.35%, 8800 BTU	$10.05	$12.51	$9.85	$9.89	$9.94	$9.63	$9.34	$9.08	$8.85	$8.65	$8.51	$8.38	$8.28
Uinta Basin													
-.5%, 11500 BTU	$30.54	$54.25	$39.84	$20.85	$18.38	$17.51	$16.70	$15.94	$15.22	$14.55	$13.91	$13.30	$12.72
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$107.87	$54.15	$46.37	$35.75	$31.30	$29.58	$28.97	$28.39	$28.81	$28.84	$28.76	$28.26
-.8%, 11600 BTU	$59.03	$100.60	$50.52	$43.33	$33.47	$29.39	$27.86	$27.33	$26.86	$27.33	$27.38	$27.31	$26.87
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$57.93	$27.61	$30.35	$26.74	$22.55	$20.87	$20.44	$20.05	$20.37	$20.39	$20.32	$19.99

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$73.12	$106.83	$116.20	$86.55	$62.40	$51.70	$44.15	$39.65	$34.20	$31.05	$28.70	$27.00
-1.8%, 13000 BTU	$72.02	$104.93	$113.20	$84.87	$61.28	$50.75	$43.25	$38.81	$33.52	$30.46	$28.24	$26.57
-2.3%, 13000 BTU	$70.37	$102.07	$108.71	$82.34	$59.59	$49.32	$41.89	$37.56	$32.51	$29.56	$27.56	$25.93
Central Appalachia												
-.7%, 12500 BTU	$73.73	$102.73	$113.55	$82.45	$59.95	$53.65	$46.15	$42.20	$41.00	$40.40	$41.00	$40.65
-.7%, 13000 BTU	$78.58	$109.46	$121.03	$87.86	$63.90	$57.17	$49.20	$44.98	$43.71	$43.06	$43.72	$43.34
-1.0%, 12500 BTU	$70.80	$99.55	$110.98	$80.52	$58.53	$52.17	$44.56	$40.53	$38.95	$37.75	$37.89	$37.25
-1.5%, 12500 BTU	$65.05	$92.03	$95.23	$69.60	$50.88	$45.37	$38.38	$34.87	$32.96	$31.31	$31.07	$31.10
Ohio												
-4%, 12500 BTU	$65.68	$80.68	$77.99	$62.05	$45.84	$38.55	$35.03	$34.54	$29.21	$26.69	$25.00	$23.50
Illinois Basin												
-3%, 11000 BTU (IL)	$31.72	$48.45	$55.70	$49.35	$42.80	$38.80	$37.50	$35.00	$32.00	$30.00	$28.00	$26.50
-3%, 11000 BTU (KY)	$33.63	$50.43	$57.37	$50.83	$44.05	$40.05	$38.76	$36.37	$33.42	$31.48	$29.33	$27.80
Powder River Basin												
-.33%, 8400 BTU	$11.57	$11.53	$10.10	$9.20	$8.90	$8.80	$8.60	$8.40	$8.50	$8.40	$9.00	$8.95
-.35%, 8800 BTU	$13.73	$13.92	$11.58	$10.82	$10.22	$10.22	$9.93	$9.87	$10.00	$9.95	$10.60	$10.60
Uinta Basin												
-.5%, 11500 BTU	$34.37	$50.63	$69.40	$62.60	$55.35	$46.55	$35.70	$28.45	$24.95	$22.45	$21.85	$21.00
Foreign Coal												
-.7%, 12000 BTU	$107.74	$124.32	$123.27	$83.56	$61.32	$56.11	$53.55	$49.84	$51.79	$52.21	$47.53	$39.73
-.8%, 11600 BTU	$100.50	$115.97	$114.93	$77.92	$57.19	$52.34	$49.97	$46.52	$48.37	$48.78	$44.44	$37.15
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$53.01	$66.04	$65.56	$47.08	$34.35	$27.05	$25.13	$26.19	$30.12	$33.30	$33.01	$29.83

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

ANNUAL AVERAGE SPOT PRI

LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$28.42	$28.36	$28.16	$27.97	$27.78	$27.57	$27.37	$27.18	$26.99	$26.79	$26.59
-1.8%, 13000 BTU	$28.22	$28.11	$27.92	$27.73	$27.54	$27.33	$27.13	$26.94	$26.75	$26.56	$26.36
-2.3%, 13000 BTU	$27.91	$27.74	$27.55	$27.36	$27.17	$26.97	$26.77	$26.59	$26.40	$26.21	$26.01
Central Appalachia											
-.7%, 12500 BTU	$44.70	$45.35	$45.99	$46.65	$47.31	$47.95	$48.83	$49.75	$50.67	$51.60	$52.55
-.7%, 13000 BTU	$47.72	$48.41	$49.10	$49.81	$50.52	$51.21	$52.15	$53.13	$54.13	$55.13	$56.14
-1.0%, 12500 BTU	$33.07	$33.40	$33.76	$34.09	$34.43	$34.74	$35.19	$35.67	$36.14	$36.63	$37.16
-1.5%, 12500 BTU	$32.70	$33.04	$33.40	$33.74	$34.08	$34.40	$34.86	$35.35	$35.82	$36.31	$36.84
Ohio											
-4%, 12500 BTU	$25.43	$25.28	$25.12	$24.97	$24.80	$24.63	$24.46	$24.30	$24.14	$23.98	$23.81
Illinois Basin											
-3%, 11000 BTU (IL)	$25.88	$25.98	$26.06	$26.15	$26.21	$26.26	$26.31	$26.38	$26.42	$26.46	$26.49
-3%, 11000 BTU (KY)	$27.44	$27.56	$27.68	$27.79	$27.88	$27.95	$28.03	$28.12	$28.20	$28.25	$28.31
Powder River Basin											
-.33%, 8400 BTU	$8.42	$8.49	$8.53	$8.54	$8.54	$8.54	$8.54	$8.54	$8.55	$8.55	$8.56
-.35%, 8800 BTU	$10.41	$10.50	$10.56	$10.60	$10.63	$10.66	$10.69	$10.73	$10.77	$10.82	$10.87
Uinta Basin											
-.5%, 11500 BTU	$15.39	$15.02	$14.67	$14.33	$14.00	$13.69	$13.39	$13.10	$12.82	$12.55	$12.30
Foreign Coal											
-.7%, 12000 BTU	$35.18	$35.24	$35.32	$35.32	$35.32	$34.91	$34.67	$34.83	$35.01	$35.23	$35.45
-.8%, 11600 BTU	$33.51	$33.59	$33.68	$33.69	$33.69	$33.32	$33.08	$33.24	$33.41	$33.62	$33.83
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$24.92	$24.97	$25.01	$25.02	$25.04	$24.79	$24.64	$24.80	$24.97	$25.18	$25.38

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

LOW CASE

August 2008

ANNUAL AVERAGE SPOT PRI

LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$22.45	$21.98	$21.42	$20.88	$20.36	$19.85	$19.35	$18.86	$18.38	$17.92	$17.47
-1.8%, 13000 BTU	$22.29	$21.79	$21.24	$20.70	$20.18	$19.67	$19.18	$18.69	$18.22	$17.76	$17.32
-2.3%, 13000 BTU	$22.05	$21.50	$20.96	$20.43	$19.92	$19.41	$18.92	$18.45	$17.98	$17.53	$17.09
Central Appalachia											
-.7%, 12500 BTU	$35.32	$35.15	$34.99	$34.83	$34.67	$34.51	$34.51	$34.51	$34.51	$34.51	$34.51
-.7%, 13000 BTU	$37.70	$37.52	$37.35	$37.19	$37.02	$36.86	$36.86	$36.87	$36.87	$36.87	$36.88
-1.0%, 12500 BTU	$26.13	$25.89	$25.68	$25.45	$25.23	$25.01	$24.87	$24.75	$24.62	$24.50	$24.41
-1.5%, 12500 BTU	$25.83	$25.61	$25.41	$25.19	$24.98	$24.76	$24.64	$24.53	$24.40	$24.29	$24.20
Ohio											
-4%, 12500 BTU	$20.09	$19.60	$19.11	$18.64	$18.18	$17.73	$17.29	$16.86	$16.44	$16.04	$15.64
Illinois Basin											
-3%, 11000 BTU (IL)	$20.45	$20.14	$19.83	$19.52	$19.21	$18.90	$18.60	$18.30	$18.00	$17.70	$17.40
-3%, 11000 BTU (KY)	$21.68	$21.37	$21.05	$20.75	$20.43	$20.12	$19.81	$19.51	$19.21	$18.90	$18.60
Powder River Basin											
-.33%, 8400 BTU	$6.65	$6.58	$6.49	$6.38	$6.26	$6.15	$6.03	$5.93	$5.82	$5.72	$5.62
-.35%, 8800 BTU	$8.22	$8.14	$8.04	$7.91	$7.79	$7.68	$7.56	$7.45	$7.34	$7.23	$7.14
Uinta Basin											
-.5%, 11500 BTU	$12.16	$11.64	$11.16	$10.70	$10.26	$9.85	$9.46	$9.09	$8.73	$8.40	$8.08
Foreign Coal: Colombia											
-.7%, 12000 BTU	$27.80	$27.32	$26.87	$26.37	$25.88	$25.13	$24.50	$24.16	$23.85	$23.56	$23.28
-.8%, 11600 BTU	$26.48	$26.04	$25.62	$25.15	$24.69	$23.98	$23.38	$23.06	$22.76	$22.49	$22.22
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$19.69	$19.36	$19.03	$18.68	$18.35	$17.84	$17.42	$17.20	$17.01	$16.84	$16.67

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BUSINESS-AS-USUAL CASE
August 2008

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ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER T(	A67

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$109.29	$100.38	$56.06	$41.01	$42.71	$44.22	$44.53	$45.07	$45.62	$46.23	$46.84	$47.55
-1.8%, 13000 BTU	$45.85	$107.07	$98.45	$55.05	$40.30	$42.10	$43.69	$44.11	$44.67	$45.24	$45.85	$46.48	$47.21
-2.3%, 13000 BTU	$44.71	$103.75	$95.54	$53.54	$39.25	$41.18	$42.90	$43.49	$44.07	$44.67	$45.28	$45.94	$46.70
Central Appalachia													
-.7%, 12500 BTU	$46.46	$108.30	$105.04	$64.73	$55.26	$59.43	$61.64	$64.04	$65.55	$64.91	$65.34	$66.08	$67.80
-.7%, 13000 BTU	$49.50	$115.41	$111.96	$69.02	$59.03	$63.45	$61.64	$68.36	$69.97	$69.28	$69.75	$70.53	$72.38
-1.0%, 12500 BTU	$44.33	$105.29	$101.83	$60.38	$47.70	$48.47	$50.82	$48.96	$49.32	$48.72	$48.94	$49.31	$50.32
-1.5%, 12500 BTU	$40.72	$93.27	$88.15	$50.33	$42.29	$44.65	$45.89	$47.17	$48.45	$48.05	$48.30	$48.67	$49.73
Ohio													
-4%, 12500 BTU	$39.19	$81.14	$78.23	$48.35	$35.60	$37.37	$38.95	$39.51	$40.06	$40.62	$41.19	$41.81	$42.52
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$50.75	$54.48	$38.12	$34.09	$34.16	$34.32	$34.61	$34.92	$35.26	$35.59	$35.93	$36.28
-3%, 11000 BTU (KY)	$28.91	$52.65	$56.29	$39.93	$35.87	$35.94	$36.15	$36.49	$36.85	$37.25	$37.62	$38.01	$38.41
Powder River Basin													
-.33%, 8400 BTU	$8.36	$11.77	$11.99	$11.08	$10.99	$11.00	$10.96	$11.00	$11.09	$11.17	$11.37	$11.54	$11.74
-.35%, 8800 BTU	$9.85	$13.78	$13.40	$12.50	$12.84	$12.98	$13.11	$13.26	$13.43	$13.61	$13.85	$14.07	$14.36
Uinta Basin													
-.5%, 11500 BTU	$29.93	$59.78	$54.61	$27.08	$25.68	$24.64	$25.00	$25.40	$25.79	$26.20	$26.61	$27.05	$27.57
Foreign Coal													
-.7%, 12000 BTU	$62.03	$125.45	$115.01	$76.58	$54.06	$50.75	$52.40	$51.40	$51.40	$51.96	$52.64	$53.33	$53.99
-.8%, 11600 BTU	$57.85	$117.00	$107.30	$71.56	$50.62	$47.66	$49.34	$48.49	$48.63	$49.30	$49.97	$50.64	$51.33
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$66.62	$58.65	$50.02	$40.44	$36.56	$36.96	$36.26	$36.30	$36.75	$37.21	$37.68	$38.18

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BUSINESS-AS-USUAL CASE

August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$109.29	$98.34	$53.89	$38.64	$39.41	$40.01	$39.51	$39.22	$38.97	$38.75	$38.52	$38.33
-1.8%, 13000 BTU	$46.79	$107.07	$96.44	$52.92	$37.98	$38.84	$39.53	$39.14	$38.88	$38.64	$38.43	$38.22	$38.06
-2.3%, 13000 BTU	$45.62	$103.75	$93.59	$51.47	$36.98	$38.00	$38.81	$38.58	$38.36	$38.15	$37.95	$37.77	$37.64
Central Appalachia													
-.7%, 12500 BTU	$47.41	$108.30	$102.90	$62.23	$52.07	$54.84	$55.76	$56.82	$57.05	$55.44	$54.77	$54.33	$54.66
-.7%, 13000 BTU	$50.52	$115.41	$109.68	$66.36	$55.62	$58.55	$55.76	$60.65	$60.90	$59.17	$58.46	$57.99	$58.35
-1.0%, 12500 BTU	$45.24	$105.29	$99.75	$58.05	$44.94	$44.73	$45.98	$43.44	$42.93	$41.61	$41.03	$40.54	$40.56
-1.5%, 12500 BTU	$41.55	$93.27	$86.35	$48.39	$39.85	$41.20	$41.51	$41.85	$42.17	$41.04	$40.48	$40.02	$40.09
Ohio													
-4%, 12500 BTU	$39.99	$81.14	$76.63	$46.49	$33.55	$34.49	$35.24	$35.05	$34.86	$34.69	$34.53	$34.38	$34.28
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$50.75	$53.37	$36.65	$32.13	$31.52	$31.05	$30.71	$30.40	$30.12	$29.83	$29.54	$29.25
-3%, 11000 BTU (KY)	$29.50	$52.65	$55.14	$38.38	$33.80	$33.17	$32.70	$32.38	$32.07	$31.81	$31.53	$31.25	$30.96
Powder River Basin													
-.33%, 8400 BTU	$8.53	$11.77	$11.75	$10.66	$10.36	$10.15	$9.92	$9.76	$9.65	$9.54	$9.53	$9.49	$9.46
-.35%, 8800 BTU	$10.05	$13.78	$13.12	$12.01	$12.10	$11.98	$11.86	$11.76	$11.69	$11.63	$11.61	$11.57	$11.58
Uinta Basin													
-.5%, 11500 BTU	$30.54	$59.78	$53.50	$26.03	$24.20	$22.74	$22.62	$22.54	$22.45	$22.38	$22.30	$22.24	$22.22
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$125.45	$112.67	$73.63	$50.94	$46.83	$47.40	$45.61	$44.74	$44.38	$44.13	$43.85	$43.52
-.8%, 11600 BTU	$59.03	$117.00	$105.11	$68.80	$47.69	$43.97	$44.63	$43.02	$42.32	$42.11	$41.88	$41.64	$41.38
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$66.62	$57.46	$48.09	$38.10	$33.74	$33.44	$32.17	$31.59	$31.39	$31.19	$30.98	$30.78

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BUSINESS-AS-USUAL CASE
August 2008

ANNUAL AVERAGE SPOT F

BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$48.29	$47.90	$48.63	$49.41	$50.14	$50.85	$51.60	$52.40	$53.17	$53.93	$54.70
-1.8%, 13000 BTU	$47.98	$47.49	$48.21	$48.98	$49.70	$50.41	$51.15	$51.94	$52.71	$53.46	$54.23
-2.3%, 13000 BTU	$47.51	$46.86	$47.58	$48.33	$49.05	$49.74	$50.47	$51.26	$52.01	$52.75	$53.51
Central Appalachia											
-.7%, 12500 BTU	$69.46	$70.43	$71.38	$73.35	$75.37	$78.29	$81.40	$83.78	$86.17	$88.54	$90.90
-.7%, 13000 BTU	$74.15	$75.18	$76.21	$78.31	$80.48	$83.61	$86.94	$89.49	$92.05	$94.59	$97.13
-1.0%, 12500 BTU	$51.38	$51.87	$52.39	$53.60	$54.86	$56.73	$58.68	$60.09	$61.47	$62.86	$64.29
-1.5%, 12500 BTU	$50.81	$51.31	$51.84	$53.04	$54.30	$56.18	$58.12	$59.53	$60.92	$62.31	$63.74
Ohio											
-4%, 12500 BTU	$43.28	$42.71	$43.38	$44.09	$44.77	$45.42	$46.11	$46.85	$47.57	$48.27	$48.98
Illinois Basin											
-3%, 11000 BTU (IL)	$36.68	$37.04	$37.42	$37.81	$38.19	$38.60	$39.00	$39.40	$39.78	$40.17	$40.58
-3%, 11000 BTU (KY)	$38.85	$39.27	$39.70	$40.14	$40.58	$41.04	$41.50	$41.96	$42.40	$42.84	$43.32
Powder River Basin											
-.33%, 8400 BTU	$11.94	$12.11	$12.24	$12.41	$12.54	$12.67	$12.81	$12.96	$13.10	$13.23	$13.38
-.35%, 8800 BTU	$14.69	$14.97	$15.19	$15.45	$15.68	$15.91	$16.15	$16.41	$16.66	$16.91	$17.17
Uinta Basin											
-.5%, 11500 BTU	$28.11	$28.62	$29.12	$29.65	$30.16	$30.66	$31.18	$31.73	$32.27	$32.80	$33.34
Foreign Coal											
-.7%, 12000 BTU	$54.66	$54.73	$54.82	$55.54	$56.27	$57.02	$57.81	$58.66	$59.55	$60.46	$61.33
-.8%, 11600 BTU	$52.06	$52.17	$52.27	$52.97	$53.68	$54.41	$55.17	$55.98	$56.83	$57.70	$58.52
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$38.71	$38.78	$38.81	$39.34	$39.90	$40.48	$41.09	$41.77	$42.48	$43.22	$43.91

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BUSINESS-AS-USUAL CASE
August 2008

ANNUAL AVERAGE SPOT F

BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$38.15	$37.13	$37.00	$36.89	$36.75	$36.60	$36.47	$36.35	$36.22	$36.07	$35.93
-1.8%, 13000 BTU	$37.91	$36.81	$36.68	$36.57	$36.43	$36.28	$36.15	$36.04	$35.90	$35.76	$35.62
-2.3%, 13000 BTU	$37.53	$36.32	$36.19	$36.08	$35.95	$35.80	$35.68	$35.56	$35.43	$35.29	$35.15
Central Appalachia											
-.7%, 12500 BTU	$54.88	$54.59	$54.30	$54.76	$55.24	$56.35	$57.54	$58.13	$58.69	$59.22	$59.71
-.7%, 13000 BTU	$58.58	$58.28	$57.97	$58.47	$58.98	$60.18	$61.45	$62.09	$62.70	$63.27	$63.80
-1.0%, 12500 BTU	$40.59	$40.21	$39.86	$40.01	$40.20	$40.83	$41.47	$41.69	$41.87	$42.05	$42.23
-1.5%, 12500 BTU	$40.14	$39.77	$39.43	$39.60	$39.80	$40.43	$41.08	$41.31	$41.50	$41.68	$41.87
Ohio											
-4%, 12500 BTU	$34.19	$33.11	$33.00	$32.92	$32.81	$32.70	$32.59	$32.51	$32.40	$32.28	$32.18
Illinois Basin											
-3%, 11000 BTU (IL)	$28.98	$28.71	$28.46	$28.23	$27.99	$27.78	$27.57	$27.34	$27.10	$26.87	$26.65
-3%, 11000 BTU (KY)	$30.70	$30.44	$30.20	$29.97	$29.74	$29.54	$29.33	$29.11	$28.88	$28.66	$28.45
Powder River Basin											
-.33%, 8400 BTU	$9.43	$9.39	$9.31	$9.26	$9.19	$9.12	$9.05	$8.99	$8.92	$8.85	$8.79
-.35%, 8800 BTU	$11.61	$11.60	$11.55	$11.53	$11.49	$11.45	$11.41	$11.38	$11.35	$11.31	$11.28
Uinta Basin											
-.5%, 11500 BTU	$22.21	$22.18	$22.15	$22.14	$22.10	$22.07	$22.04	$22.01	$21.98	$21.94	$21.90
Foreign Coal: Colombia											
-.7%, 12000 BTU	$43.18	$42.42	$41.71	$41.46	$41.24	$41.04	$40.86	$40.70	$40.56	$40.44	$40.28
-.8%, 11600 BTU	$41.13	$40.44	$39.76	$39.55	$39.35	$39.16	$38.99	$38.84	$38.71	$38.59	$38.44
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$30.58	$30.06	$29.53	$29.37	$29.24	$29.13	$29.04	$28.98	$28.93	$28.91	$28.84

THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 11-250

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

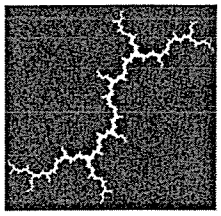
Investigation of Merrimack Station Scrubber Costs and Cost Recovery

PREFILED TESTIMONY OF MICHAEL E. HACHEY
ON BEHALF OF TRANSCANADA POWER MARKETING LTD. AND
TRANSCANADA HYDRO NORTHEAST INC.

ATTACHMENT 17

Synapse Energy Economics, Inc. analysis – link:

http://www.synapse-energy.com/cgi-bin/synapsePublications.pl?filter_type=Topic&filter_option=Price+Forecasting&advanced=false



Synapse
Energy Economics, Inc.

Avoided Energy Supply Costs in New England:

2007 FINAL REPORT

Revised – January 3, 2008

AUTHORS

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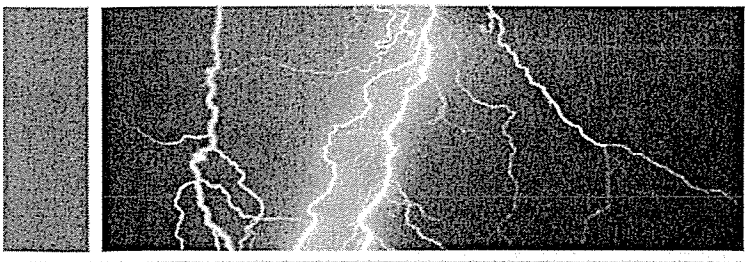
PREPARED FOR

Avoided-Energy-Supply-Component (AESC) Study Group



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1. Executive Summary

A. Background to Report

This 2007 Avoided-Energy-Supply-Component (AESC) report provides projections of marginal energy supply costs which will be avoided due to savings in electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England. These projections were developed in order to support energy efficiency program decision-making and regulatory filings during 2008 and 2009. The program administrators will use these projections in their efficiency program decision-making and regulatory filings in 2008 and 2009.

The 2007 AESC Study updates the 2005 AESC Study to reflect current market conditions and cost projections. The report provides detailed projections for an initial fifteen year period beginning in 2007 and escalation rates for another fifteen years from 2022 through 2037. All values are reported in 2007$ unless noted otherwise.

The 2007 AESC Study was sponsored by a group of electric utilities, gas utilities and other efficiency program administrators (collectively, "program administrators"). The sponsors, along with non-utility parties and their consultants, formed a 2007 AESC Study Group to oversee the design and execution of the report. The 2007 AESC sponsors include Berkshire Gas Company, KeySpan Energy Delivery New England (Boston Gas Company, Essex Gas Company, Colonial Gas Company, and EnergyNorth Natural Gas, Inc.), Cape Light Compact, National Grid USA, New England Gas Company, NSTAR Electric & Gas Company, New Hampshire Electric Co-op, Bay State Gas and Northern Utilities, Northeast Utilities (Connecticut Light and Power, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas), Unitil (Fitchburg Gas and Electric Light Company and Unitil Energy Systems, Inc.), United Illuminating, Southern Connecticut Gas and Connecticut Natural Gas, the State of Maine, and the State of Vermont. The following agencies or organizations are represented in the Study Group: Connecticut Energy Conservation Management Board, Massachusetts Department of Public Utilities, Massachusetts Division of Energy Resources, Massachusetts Low-Income Energy Affordability Network (LEAN) and other Non-Utility Parties, New Hampshire Public Utilities Commission, and Rhode Island Division of Public Utilities and Carriers.

The 2007 AESC Study Group specified the scope of work, selected the contractor, and monitored progress of the study. The report was prepared by a project team consisting of contractors from Synapse Energy Economics (Synapse), Swanson Energy Group and Resource Insight (Synapse project team). Carl Swanson led the analysis of avoided natural gas costs and David White was lead investigator on projections of prices of oil and other fuels. Michael Drunsic was responsible for projecting electricity prices with advice from Bruce Biewald, Paul Chernick and David White. Doug Hurley provided advice on the structure and operation of the New England market, including ICAP and LICAP issues.

Paul Chernick developed zonal avoided electric costs by costing period, including analyses of DRIPE. Bruce Biewald, Paul Chernick, and Lucy Johnston developed estimates of environmental externalities. Jennifer Kallay provided research and analytic support including data collection, literature searches, spreadsheet analyses, documentation, and drafting. Rick Hornby served as project manager and editor. The Synapse project team presented its analyses and projections to the 2007 AESC Study Group in nine substantive analyses, each of which was reviewed in a conference call.

B. Organization of Report

The report provides detailed projections of marginal energy supply costs for an initial fifteen year period beginning in 2007 and escalation rates for another fifteen years from 2022 through 2037. All values are reported in 2007$ unless noted otherwise.

The report is organized as follows:

- Chapter 2 - projection of natural gas prices for electric generation as well as a projection of avoided natural gas costs by retail end-use sector.
- Chapter 3 - projection of crude oil prices.
- Chapter 4 - projection of fuel prices by retail end-use sector.
- Chapter 5 - projection of electric energy prices and a description of the modeling methodology and assumptions.
- Chapter 6 - projection of avoided electricity costs and a description of the underlying assumptions.
- Chapter 7 - projection of environmental effects and environmental externalities.
- Appendix A – derivation of common modeling assumptions.
- Appendix B – avoided gas costs in 2007$ and nominal$.
- Appendix C – detailed input assumptions for electric energy price forecasts.
- Appendix D – usage guide for avoided electricity supply costs.
- Appendix E – avoided electricity supply costs in 2007$ and nominal$.

C. Results and Comparison to 2005 AESC

Avoided Costs of Natural Gas to Retail Customers

The 2007 AESC projections of marginal natural gas supply costs to retail customers over the next fifteen years range from $8.00 to $12.00 per dekatherm (DT) (2007$). The 2007 AESC projections are generally higher than the 2005 AESC projections, shown in

Exhibit ES-1[1]. Exceptions to these generally higher results occur in commercial/industrial non-heating applications in Southern New England and Vermont.

The differences between the 2007 AESC projections and the 2005 AESC projections are primarily due to a higher projection for natural gas prices, discussed further below. In addition, AESC 2007 projects a higher avoided retail margin for residential applications, especially in Northern & Central New England, compared with AESC 2005. The lower projection of avoided cost in AESC 2007 for commercial and industrial non-heating, applications in Southern New England is primarily due to a lower projection of avoided retail margin for that application. The AESC 2007 projection is based upon a volume weighted average of the estimated avoided margins for the industrial and the commercial sectors respectively, while the AESC 2005 projection is based only on the estimated avoided commercial retail margin. This difference in methodology also appears to explain the lower AESC 2007 estimates of commercial and industrial non-heating avoided costs in Vermont.

[1] 2007 AESC values levelized for 15 years (2008 - 2022) at discount rate of 2.22%. 2005 AESC values levelized for 15 years (2006 - 2020) at discount rate of 2.03%.

Exhibit ES-1. Comparison of Levelized Avoided Costs of Gas Delivered to Retail Customers by End Use: AESC 2005 and AESC 2007 (2007$/Dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.	5-mon.
Northern & Central New England								
AESC 2005 (a)	$10.60	$10.50	$10.42	$10.50	$9.49	$9.58	$9.53	$10.07
AESC 2007	$12.03	$11.85	$10.86	$11.56	$9.78	$10.78	$10.48	$11.27
2005 to 2007 change	13.5%	12.8%	4.2%	10.0%	3.0%	12.6%	9.9%	11.9%
Southern New England								
AESC 2005 (a)	$10.88	$10.78	$10.66	$10.78	$9.30	$9.42	$9.36	$10.14
AESC 2007	$12.55	$12.32	$11.15	$11.97	$9.12	$10.29	$9.94	$11.18
2005 to 2007 change	15.3%	14.3%	4.5%	11.1%	-2.0%	9.2%	6.2%	10.3%
Vermont								
AESC 2005 (a)	$9.78	$9.70	$9.62	$9.70	$8.53	$8.62	$8.57	$9.20
AESC 2007	$11.44	$11.20	$10.01	$10.85	$8.00	$9.19	$8.84	$9.95
2005 to 2007 change	17.0%	15.4%	4.1%	11.8%	-6.2%	6.7%	3.1%	8.2%

Source of AESC 2005 levelized retail avoided costs is Exhibit ES-3, page 5, for 15 years levelized.
(a) Factor to convert 2005$ to 2007 $ 1.0547
Note: AESC 2005 levelized costs for 15 years, 2005 - 2019. AESC 2007 levelized costs for 16 years, 2007 - 2022.

Avoided Costs of Electricity to Retail Customers

The 2007 AESC projections of marginal electric energy and capacity costs to retail customers are substantially higher than those in the 2005 AESC Study. The 15 year levelized projections[2] of marginal electric energy costs from the 2005 and 2007 AESC studies are shown in Exhibit ES-2.

[2] 2007 AESC values and AESC 2005 values levelized for 15 years (2008 - 2022) at discount rate of 2.22%.

Exhibit ES-2. 15 Year Levelized Avoided Electric Energy Costs - AESC 2005 vs. AESC 2007 ($2007)

AESC 2005	Winter Peak Energy $/kWh	Winter Off Peak Energy $/kWh	Summer Peak Energy $/kWh	Summer Off-Peak Energy $/kWh
Maine (ME)	0.061	0.051	0.054	0.043
Boston (NEMA)	0.064	0.052	0.061	0.044
Rest of Massachusetts (non-NEMA)	0.064	0.052	0.061	0.044
Central & Western Massachusetts (WCMA)	0.064	0.052	0.061	0.044
New Hampshire (NH)	0.063	0.051	0.060	0.044
Rhode Island (RI)	0.064	0.052	0.060	0.045
Vermont (VT)	0.064	0.052	0.061	0.045
Norwalk (NS)	0.068	0.053	0.064	0.045
Southwest Connecticut (SWCT)	0.066	0.053	0.063	0.045
Rest of Connecticut (non-SWCT)	0.066	0.052	0.062	0.045

AESC 2007				
Maine (ME)	0.084	0.062	0.086	0.060
Boston (NEMA)	0.095	0.069	0.101	0.068
Rest of Massachusetts (non-NEMA)	0.093	0.069	0.098	0.067
Central & Western Massachusetts (WCMA)	0.094	0.070	0.099	0.069
New Hampshire (NH)	0.090	0.067	0.093	0.065
Rhode Island (RI)	0.093	0.068	0.098	0.066
Vermont (VT)	0.096	0.070	0.101	0.069
Norwalk (NS)	0.099	0.072	0.112	0.071
Southwest Connecticut (SWCT)	0.098	0.072	0.106	0.070
Rest of Connecticut (non-SWCT)	0.097	0.071	0.104	0.069

Change from AESC 2005				
Maine (ME)	0.023	0.011	0.032	0.017
Boston (NEMA)	0.031	0.017	0.040	0.024
Rest of Massachusetts (non-NEMA)	0.029	0.017	0.038	0.023
Central & Western Massachusetts (WCMA)	0.030	0.018	0.038	0.024
New Hampshire (NH)	0.027	0.015	0.034	0.021
Rhode Island (RI)	0.029	0.016	0.038	0.022
Vermont (VT)	0.032	0.018	0.040	0.025
Norwalk (NS)	0.031	0.019	0.048	0.026
Southwest Connecticut (SWCT)	0.032	0.019	0.043	0.025
Rest of Connecticut (non-SWCT)	0.031	0.019	0.042	0.024

% Change from AESC 2005				
Maine (ME)	39%	22%	59%	38%
Boston (NEMA)	48%	33%	66%	54%
Rest of Massachusetts (non-NEMA)	46%	32%	62%	52%
Central & Western Massachusetts (WCMA)	47%	34%	63%	55%
New Hampshire (NH)	43%	30%	56%	48%
Rhode Island (RI)	46%	31%	63%	48%
Vermont (VT)	49%	34%	65%	55%
Norwalk (NS)	46%	37%	75%	58%
Southwest Connecticut (SWCT)	48%	36%	68%	56%
Rest of Connecticut (non-SWCT)	48%	35%	68%	54%

The 2007 AESC avoided energy costs are about 2.2 cents/kWh higher than the 2005 AESC on an annual average basis, with even higher differentials in peak costing periods. The major factors underlying those differentials are higher projections of natural gas production prices, CO_2 regulation compliance costs, and retail supply margins. As indicated in Exhibit ES-3, those three factors would account for an annual average differential of about 2.6 cents/kWh assuming a marginal gas-fired unit with a heat rate of 9,500 Btu/kWh.

Exhibit ES-3. Illustrative Calculation of Differential in Avoided Energy Costs – 2007 versus 2005

Factor	Differential – 2007 AESC versus 2005 AESC	Impact on marginal electric energy supply cost (cents/kWh) assuming a gas-fired unit with 9,500 btu/kWh heat rate
Natural Gas Prices ($/MMBtu)	1.25	1.2
CO_2 compliance costs $/ton	9.52	0.6
Retail Adder	10%	0.8
Total		2.6

The projections of marginal capacity costs are shown in Exhibit ES-4.

Exhibit ES-4. 15 Year Levelized Avoided Electric Capacity Costs - AESC 2005 vs. AESC 2007

	Annual Market Capacity Value		
Zone	AESC 2005	AESC 2007	Change
Maine (ME)	50.37	100.30	99%
Boston (NEMA)	77.08	107.30	39%
Rest of Massachusetts (non-NEMA)	72.02	102.60	42%
Central & Western Massachusetts (WCMA)	72.02	102.60	42%
New Hampshire (NH)	72.02	107.30	49%
Rhode Island (RI)	72.02	102.60	42%
Vermont (VT)	72.02	103.70	44%
Norwalk (NS)	81.62	102.60	26%
Southwest Connecticut (SWCT)	76.54	107.30	40%
Rest of Connecticut (non-SWCT)	74.81	102.60	37%

The 2007 AESC projections of marginal electric capacity costs are higher than those in the 2005 AESC due primarily to the assumption that prices in the Forward Capacity Market (FCM) will be set by gas fired peaking combustion turbines.

Demand-Reduction-Induced Price Effect ("DRIPE")

Reductions in the quantity of energy and/or capacity that customers will need in the future due to efficiency and/or demand response programs are expected to result in lower prices for electric energy and capacity in wholesale markets. This impact of efficiency programs on market prices is referred to as Demand-Reduction-Induced Price Effect (DRIPE).

AESC 2007 presents 15-year levelized energy and capacity DRIPE estimates by zone in Exhibit ES-5 below. We recommend that the estimate of capacity DRIPE be updated by

analyzing actual bids once ISO-NE releases the bids received in the FCM auction in 2008. We also recommend that program administrators include DRIPE values in their analyses of demand side management (DSM), unless specifically prohibited from doing so by state or local law or regulation.

Exhibit ES-5. 15 Year Levelized Energy and Capacity DRIPE for Installations in 2008 by Zone

	Energy DRIPE				Capacity DRIPE
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	
Zone	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Maine (ME)	0.008	0.007	0.013	0.006	22.80
Boston (NEMA)	0.008	0.007	0.016	0.007	22.80
Rest of Massachusetts (non-NEMA)	0.010	0.008	0.018	0.007	24.63
Central & Western Massachusetts (WCMA)	0.009	0.007	0.016	0.006	24.63
New Hampshire (NH)	0.008	0.007	0.014	0.006	22.80
Rhode Island (RI)	0.009	0.007	0.015	0.007	24.63
Vermont (VT)	0.008	0.006	0.014	0.005	22.80
Norwalk (NS)	0.010	0.008	0.022	0.011	24.63
Southwest Connecticut (SWCT)	0.009	0.008	0.019	0.010	22.80
Rest of Connecticut (non-SWCT)	0.010	0.008	0.022	0.011	24.63

These estimates are very small when expressed in terms of impacts on the market prices of energy and capacity, i.e., reductions of a fraction of a percent. These impacts are projected to dissipate over four to five years as the market reacts to the new, lower level of energy and capacity required. However, DRIPE impacts are significant when expressed in absolute dollar terms, since very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. Moreover, consideration of DRIPE impacts can also increase the cost-effectiveness of DSM programs on the order of 15% to 20%, because the estimated absolute dollar benefits of DRIPE are being attributed to a relatively small quantity of reductions in energy and/or capacity.

The AESC 2007 estimates of energy and capacity DRIPE vary by zone. Using West-Central Massachusetts as an example, the estimate of energy DRIPE in the summer on-peak period is 1.6 cents/kWh. This compares to an avoided electricity cost of 9.9 cents/kWh for that same zone and costing period. (AESC 2005 did not develop an estimate of energy DRIPE). Again, using West-Central Massachusetts as an example, the estimate of capacity DRIPE is $25/kW-year (15 year levelized value in 2007$). This compares to an avoided capacity cost of 103/kW-year for that same zone and costing period. (This estimate is between the corresponding 2005 AESC estimates for that zone of $299/kW-year and $17/kW-year[3], which are 15 year levelized values in 2005$.)

[3] Exhibit A2-5, 2005 AESC.

CO_2 Externality

Externalities are impacts from the production of a good or service that are neither reflected in the price of that good or service nor considered in the decision to provide that good or service. There are many externalities associated with the production of electricity, including the adverse impacts of emissions of SO_2, mercury, particulates, NO_x and CO_2. However, the magnitude of most of those externalities has been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of their adverse impacts in their production and use decisions. In other words, a portion of the costs of the adverse impact of most of these externalities has already been "internalized" in the price of electricity.

AESC 2007 identifies the impacts of carbon dioxide as the dominant externality associated with marginal electricity generation in New England over the study period for two main reasons. First, policy makers are just starting to develop and implement regulations that will "internalize" the costs associated with the impacts of carbon dioxide from electricity production and other energy uses. The Regional Greenhouse Gas Initiative and anticipated future federal CO_2 regulations will internalize a portion of the "greenhouse gas externality," but AESC 2007 projects that the externality value of CO_2 will still be high even with those regulations. Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal emissions of SO_2, mercury, particulates and NO_X, but substantial emissions of CO_2.

AESC 2007 has developed a projection of annual additional environmental costs associated with emissions of CO_2 in New England. The estimates are equal to the cost of limiting CO_2 emissions to a "sustainability target" level, estimated to be a control cost of $60/ton, and minus the forecast value of CO_2 allowances under the cap and trade regulations expected over the study period. An additional CO_2 environmental cost of $60/ton translates into an electricity cost adder of approximately 4.0 cents/kWh if a natural gas generating unit is on the margin. The AESC 2007 estimates of 15-year levelized CO_2 additional environmental costs by zone are presented in Exhibit ES-6 below. As with DRIPE, we recommend that program administrators include CO_2 additional environmental costs in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation.

Exhibit ES-6. 15 Year Levelized CO_2 Externalities by Zone

	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Zone	$/kWh	$/kWh	$/kWh	$/kWh
Maine (ME)	0.028	0.027	0.031	0.030
Boston (NEMA)	0.028	0.027	0.031	0.030
Rest of Massachusetts (non-NEMA)	0.028	0.028	0.031	0.030
Central & Western Massachusetts (WCMA)	0.028	0.028	0.031	0.030
New Hampshire (NH)	0.028	0.027	0.031	0.030
Rhode Island (RI)	0.028	0.028	0.031	0.030
Vermont (VT)	0.028	0.027	0.031	0.030
Norwalk (NS)	0.028	0.028	0.031	0.030
Southwest Connecticut (SWCT)	0.028	0.027	0.031	0.030
Rest of Connecticut (non-SWCT)	0.028	0.028	0.031	0.030

2. Natural Gas Price Forecast

This Chapter provides a projection of natural gas prices for electric generation as well as a projection of avoided natural gas costs by retail end-use sector.

A. Overview of New England Gas Market

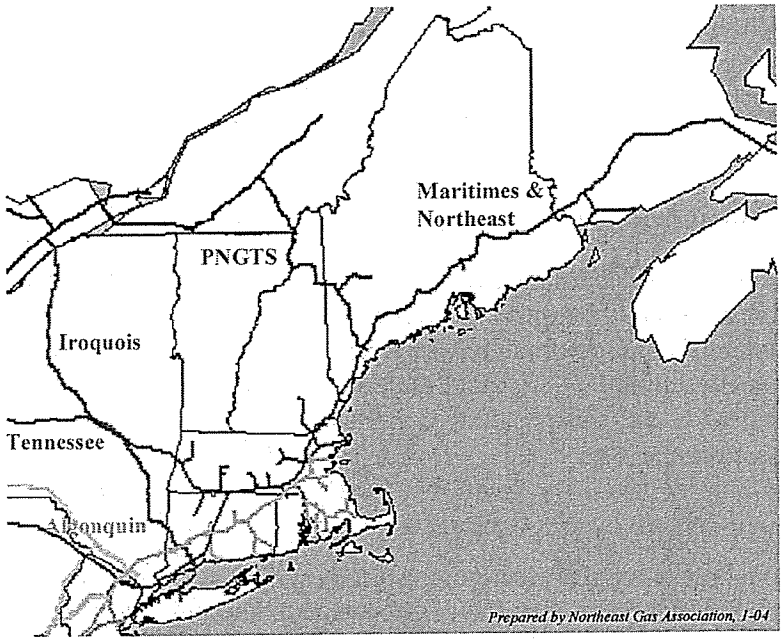
Natural gas arrived later in New England than in much of the rest of America because of its distance from the major supplies of natural gas in the Southwest. Now, however, natural gas accounts for approximately 23 percent of New England energy consumption, which is the same fraction of energy consumption as in the United States as a whole. Gas consumption has been and is expected to continue to grow in New England with electricity generation the most rapidly growing sector. Most of the gas purchased by consumers in New England is delivered by local distribution companies (LDCs), but some is delivered directly by pipelines, usually to electric generation facilities.

Because of the large seasonal temperature changes in New England and the amount of heating load, natural gas use is seasonal. On average, about twice as much gas is used in January than in the summer months. However, much of the summer natural gas consumption is for electricity generation. Since generators often receive gas directly from pipelines, the LDCs have a much greater swing of gas load; an LDC's January gas load can be five times its summer load. Because of these large swings in gas load, LDCs must have gas stored in the summer to serve customer gas requirements in the winter. This stored gas is mostly stored in underground facilities, many of which are depleted natural gas producing fields. Most of the underground storage facilities that serve the New England LDCs are located in Pennsylvania, although storage facilities in New York, Michigan, and Ontario are also used. Since these underground storage facilities are relatively far from New England, liquefied natural gas (LNG) and propane stored in New England are used to meet the peak customer requirement on the colder days of the winter.

Originally the natural gas delivered in New England came from the supply areas of Appalachia or the Southwest. New England's natural gas supply has diversified; gas also now comes from western Canada, from Nova Scotia, and by ship as LNG from Trinidad and Tobago, Nigeria, Algeria, and other LNG exporting countries.

The physical system through which gas is delivered to and within the New England region, excluding Vermont, currently consists of five pipelines and one liquefied natural gas terminal. The pipelines are Tennessee, Algonquin, Maritimes & Northeast, Portland Natural Gas, and Iroquois, and the LNG terminal is owned and operated by Distrigas. A map of these five pipelines is shown in Exhibit 2-1 below. Distrigas receives LNG by tanker in Boston Harbor and delivers that supply as gas into Algonquin, the KeySpan system, the Mystic Electric Generating Station, and as LNG by truck to local distribution company (LDC) storage tanks throughout the region. The one LDC serving northern Vermont receives its gas from TransCanada Pipelines at Highgate Springs on the border with Canada.

Exhibit 2-1. Pipelines Supplying New England



Tennessee and Algonquin deliver the majority of the natural gas that comes into New England. These two pipelines also deliver gas directly to a number of electric generating units and certain very large customers, as well as indirectly through deliveries to LDCs who in turn distribute that gas to retail customers.

A more extensive discussion of the New England gas industry and gas supply is published by the Northeast Gas Association (NEGA).[4]

[4] Northeast Gas Association, "Statistical Guide to the Northeast U.S. Natural Gas Industry 2006" (NEGA Statistics 2006).

B. Forecast Commodity Price of Gas

i. Development of Henry Hub Natural Gas Price Forecast

The forecasted commodity price of gas in New England begins with a forecast of the price of gas at the Henry Hub, the most relevant pricing point for US gas supply costs. Henry Hub natural gas prices make a good starting point for the forecast for numerous reasons, including: the North American natural gas market is highly integrated, the Henry Hub is located in the US Gulf Coast area which is the dominant producing region of the United States, the Henry Hub is the most liquid trading hub with the longest history of public trading on the New York Mercantile Exchange ("NYMEX"), and market prices of gas produced in other regions of the United States and Canada reflect Henry Hub prices with an adjustment for their location – referred to as a basis differential. A basis differential is defined as the natural gas price in a market location minus the gas price at the Henry Hub.

Natural gas production forecasts through 2020 in Annual Energy Outlook 2007 (AEO 2007), prepared by the Energy Information Administration (EIA) within the US Department of Energy, indicate that production from the lower 48 states represents at least 70% of US supply with the remaining coming from imports via pipeline and imports via liquified natural gas terminals. AEO 2007 projects an increase in US production to approximately 80% of total supply by 2020 due to greater forecasted deliveries of Alaskan natural gas to the lower 48 states beginning in 2018. It also projects a decline in pipeline imports due to simultaneous declines in Canadian production and increases in Canadian consumption. AEO 2007 also projects imports of LNG to increase by a factor of almost six relative to 2005 levels requiring the expansion of existing terminals and the construction of new terminals. However, even with this increase, LNG will still represent less than 15% of US supply as shown in the exhibit below.

Exhibit 2-2. Sources of US Natural Gas Supply 2005 and 2020[5] (Tcf)

Sources of Supply	2005 (actual)	2020 (Reference Case forecast)	Change 2020 vs. 2005
US Production	18.30	20.86	2.56
Imports via Pipeline	3.01	1.65	(1.36)
Imports via LNG	0.57	3.69	3.12
Total	21.87	26.21	4.34

The first step towards projecting New England natural gas prices was to develop an annual Henry Hub natural gas price forecast. The natural gas price forecast at the Henry Hub was based on data from the AEO 2007.[6] The AEO 2007 was the optimal starting

[5] EIA, AEO 2007, Table A13, page 159.

[6] AEO 2007 prices are expressed in 2005$. Those prices are converted into 2007$ using the indexes and conversion factors specified as major assumptions.

point because it is public, transparent, and incorporates the long-term feedback mechanisms of energy prices upon supply, demand, and competition among fuels. AEO 2007 is comprised of 34 different forecast cases, each incorporating different assumptions.[7] The most likely case is called a Reference Case. The Reference Case assumes US economic growth of 2.9% per year and oil and gas prices that decline from current levels and then begin a slow rise. By 2030, the AEO 2007 expects the Reference Case average crude oil prices to be about $59.00 per barrel and US wellhead natural gas prices to be $5.80 per Mcf in 2007 dollars.

A review of the Henry Hub natural gas prices in AEO 2007 found that none of the AEO forecasts of Henry Hub gas prices over the long-term were supportable. A major source of disagreement with the AEO 2007 forecasting was with the EIA's assumptions about technological progress in oil and gas finding. As indicated in Exhibit 2-3, the AEO Reference Case assumes that, relative to actual experience over the past ten years,

- the success rate of oil and gas drilling will improve at a slower pace,
- the finding rates for gas will improve at a faster pace, and
- the costs of drilling wells will decline at a faster rate.

For the reasons presented below, we agree with the EIA's projections that the success rate of drilling will improve at a slower pace but we disagree with their projected improvements in finding rates and drilling costs.

The EIA projections of improvements in finding rates and drilling costs are inconsistent with recent trends. As shown in Exhibit 2-4, the cost per foot of drilling exploration wells doubled since the mid-1990s and the cost per foot of development wells more than doubled from 1995 to 2004. The reserves found per foot drilled for development wells dropped 40% while the productivity of exploration drilling dropped about two-thirds since the mid-1990s. Consequently, the drilling cost per Mcf of natural gas reserves found[8] increased from about $0.50 per Mcf in the mid-1990s to over $3.00 per Mcf for exploratory wells and to slightly under $2.00 per Mcf for development wells (all in 2000$).

The EIA did make some effort to consider observed trends. As stated in the AEO 2007, "...for the AEO 2007 projections, the re-estimations capture all the cost increases and outcomes for the E & P activity that occurred through December 31, 2004." However, analysis and experience indicate that the EIA's re-estimations were not sufficient to capture the recent facts and likely future reality regarding oil and gas drilling costs and productivity over the next several years. This is shown by the large differences between recent facts and the EIA assumptions about finding rates and drilling costs in Exhibit 2-3.

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[7] See AEO 2007 Appendix E and especially Table E1, page 212.

[8] These drilling costs do not include the costs of buying leases, performing geophysical surveys, or the costs, including royalty and taxes, of producing gas.

Exhibit 2-3. Comparison of AEO 2007 Assumptions about Improvements in Gas Finding Productivity and Drilling Costs (Reference Case) with Actual Data from 1994 to 2004

		Average Annual Improvement	
		Forecast	Actual
		AEO 2007 Reference Case	1994-96 to 2003-2004
	units	(a)	(b)
Success Rates of Oil and Gas Drilling (Annual Improvement)			
Exploratory Wells	% per year	0.5 to 1.0	5.0
Development Wells	% per year	0.5	1.1
Finding Rates for Gas, Improvement (Mcf found per successful gas well foot drilled)			
Exploratory Wells	% per year	0.0 to 3.0	-12.4
Development Wells	% per year	1.0	-4.9
Reduction in Drilling Costs			
Exploratory Wells	% per year	0.9 to 1.0	-8.3
Development Wells	% per year	0.9 to 1.0	-9.5

(a) Assumptions to the Annual Energy Outlook 2007, Table 53, page 102.
(b) EIA Annual Energy Review 2005; Tables 4.6, 4.7 and 4.8;
EIA Performance Profiles of Major Energy Producers 2005.

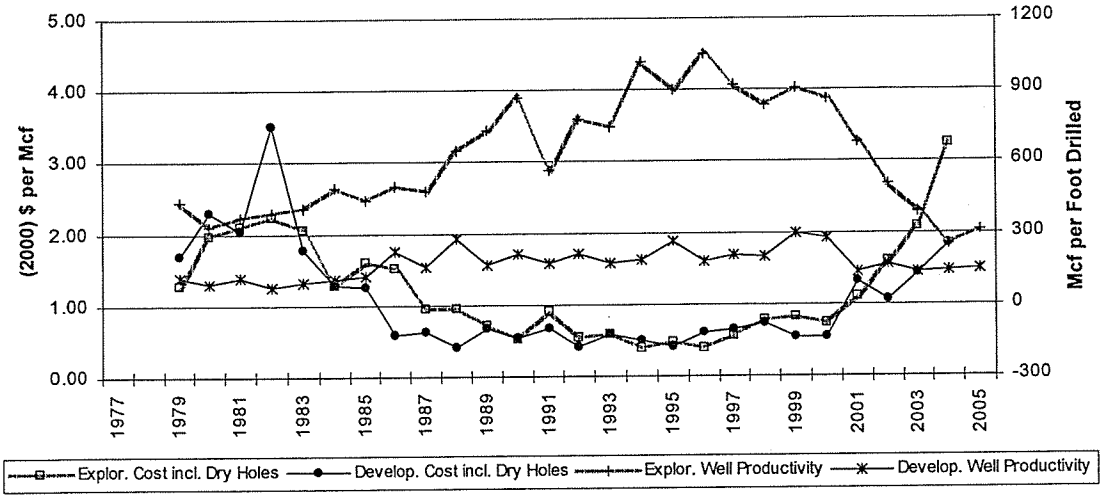
As shown in Exhibit 2-3, AEO 2007 assumed that the success rate of oil and gas drilling would be less than the rate experienced on average from 1994-1996 through 2003-2004. However, this assumption merely reflected the fact that success rates are now relatively high, about 50% for exploratory wells and about 90% for development wells. It is true that oil and gas drilling technology is improving and there have been a higher percentage of successful wells over time as evidence of this trend (Exhibit 2-4 provides more detail). North America is now experiencing a gas drilling boom similar to that of the late 1970s and early 1980s. After the drilling boom of the late 1970s and early 1980s, drilling costs did decrease and drilling productivity did increase and such may happen again. Thus, it is also reasonable to expect that as the number of drilling rigs and experienced crews grows to fill the demand and as technology and knowledge improves in finding and developing non-conventional gas reservoirs, declining drilling costs and increasing productivity of drilling could be experienced in the future.

However, one cannot ignore the reduced finding rate and greater costs of finding gas; it is simply becoming increasing difficult and expensive to extend existing reservoirs and find new ones. New reservoirs are smaller, deeper in the sea, in more remote areas, and have less permeability in the reservoirs. Thus, although technology is improving, the data show that the difficulty in accessing new or extended reservoirs for gas is offsetting any gains made through technological improvements.

In addition, the increase in the number of wells and footage drilled has led to price increases for drilling. These increases have been further exacerbated by price increases for drilling materials (i.e., steel) caused by worldwide economic growth. In short, further strong improvement in success rates, especially for development wells, will be difficult.

AEO 2007's assumed improvements in finding rates of 0 to 3% per year and reductions in drilling costs of about 1% per year are not consistent with the actual rates experienced on average from 1994-1996 through 2003-2004. To the contrary, finding rates over that period fell sharply and drilling costs escalated sharply.

Exhibit 2-4. US Gas Wells Drilling Productivity (Mcf per foot drilled) and Drilling Cost of Reserves (2000$ per Mcf)



Fortunately, AEO 2007 provided alternate scenarios including the Oil and Gas Slow Technology Case and the Oil and Gas Rapid Technology Case. The AEO 2007 Oil and Gas Rapid Technology Case had 50% more rapid cost reduction and drilling productivity improvement than the Reference Case. Conversely, the AEO 2007 Oil and Gas Slow Technology Case assumed that cost and drilling productivity improvement were 50% less than the Reference Case. The Oil and Gas Slow Technology Case represents a more reasonable starting point than the Reference Case. In the Oil and Gas Slow Technology Case, the EIA continues to assume that technological progress will reduce drilling costs and increase drilling productivity year after year, contrary to the actual trends shown in the exhibit above. The recent rates of change for productivity improvements and drilling cost reductions are negative, not the small but positive numbers assumed by the EIA, even in its Slow Technology Case. Therefore, the Henry Hub gas price forecast in this study began with the AEO 2007 Oil and Gas Slow Technology Case forecast, and then made adjustments to reflect the assumption that drilling costs would continue to increase or remain high and finding productivity per foot drilled would continue to fall or remain at current low levels for a while.

In order to develop a forecast that captures the effects of both technological progress and declining productivity and increasing costs of drilling for and finding natural gas, this forecast starts with the gas price forecast in the Slow Technology Case in the AEO 2007 and adds to this price the difference in the price between the AEO 2007 Oil and Gas Slow Technology Case and the AEO 2007 Oil and Gas Rapid Technology Case. The difference in the two cases represents the difference in the rates of improvement (or decline) in drilling costs and drilling productivity. This difference, when added to the prices from the Slow Technology Case, provided a reasonable representation of the reality of increasing

drilling costs and declining drilling productivity in the recent past and near future. The result is representative of the Henry Hub natural gas price under "a less than Slow Technology Case." In other words, the Henry Hub natural gas price under "a less than Slow Technology Case" will be above the Slow Technology Case forecast price by the same differential as the Henry Hub natural gas price under the "Rapid Technology Case" is below the Slow Technology Case forecast price. A forecast that provides a reasonable reflection of the likely price impacts of increasing drilling costs and declining drilling productivity was developed by adding the price differential to the Slow Technology Case forecast price.

As a check on the validity of this forecast, the forecast prices for 2007-2012 were compared to the Henry Hub futures prices from NYMEX.[9] Annual averages using actual monthly NYMEX prices for January through March 2007 and NYMEX futures prices for April 2007 through December 2012[10] were calculated. This comparison indicated that near-term prices forecast under the methodology outlined above for 2007 through 2012 were, on average, 98% of the Henry Hub futures prices as of mid-March 2007[11] when expressed in 2007$. Although this is a modest discrepancy, it was determined that the optimal approach would be to use a combination of Henry Hub futures prices in the near-term (2007-2012) and projections derived from the AEO 2007 Oil and Gas Slow Technology Case described above in the long-term (2013-2022).

ii. Annual Henry Hub Natural Gas Price Forecast

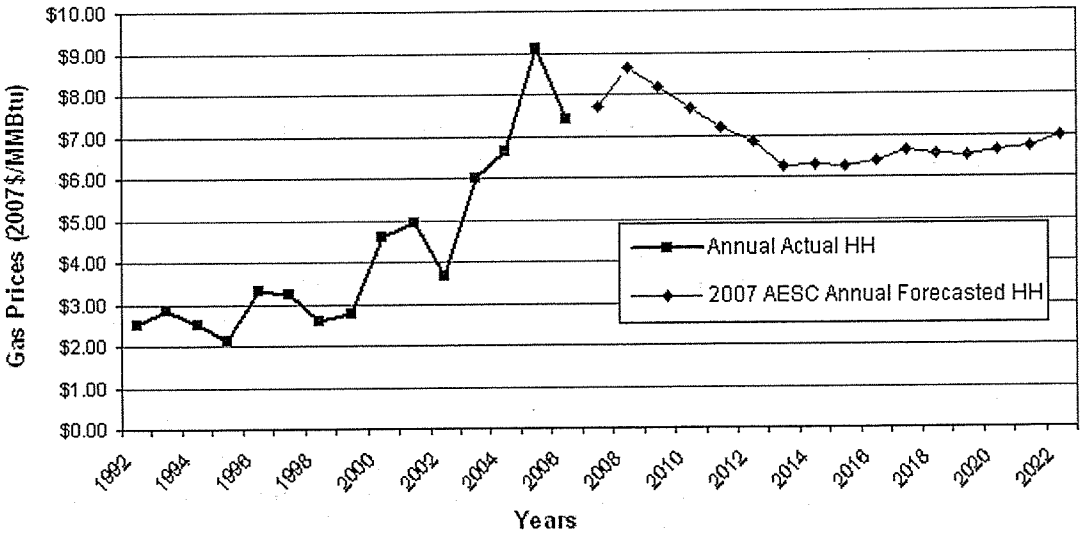
The AESC 2007 Henry Hub annual natural gas price forecast is shown in the exhibit below relative to the actual Henry Hub prices from 1992 through 2006. Actual Henry Hub prices were in the $3.00/MMBtu (2007$) range from 1992 through 1999, and have increased steadily since then. The AESC 2007 forecast projects that prices decline to the $6.00 to $7.00/MMBtu range, and then stabilize at that level through 2022.

[9] The futures market represents the consensus of market participants who do have a reasonable knowledge of near-term market and industry facts. See the paper by Adam Sieminski, "Varying Views on the Future of the Natural Gas Market: Secrets of Energy Price Forecasting," 2007 EIA Energy Outlook, Modeling and Data Conference, Washington DC, March 28, 2007. Available at www.eia.doe.gov/oiaf/aeo/conf/index.htm.

[10] As of May 2, 2007.

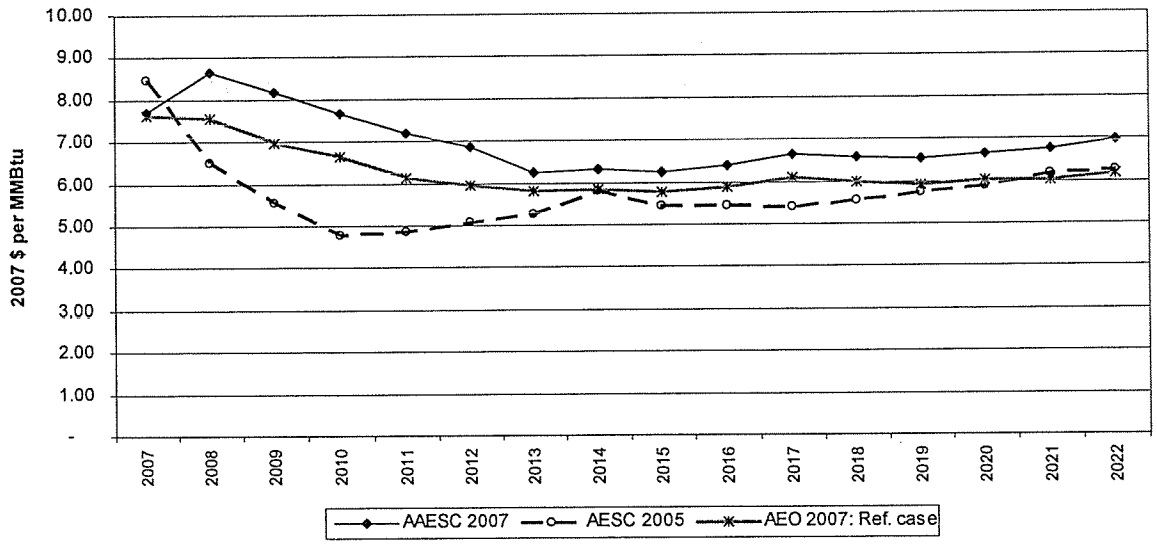
[11] NYMEX ClearPort market prices as of May 2, 2007.

Exhibit 2-5. Annual Actual and Forecasted Henry Hub Natural Gas Prices (2007$/MMBtu)



The AESC 2007 forecast is approximately 9% higher than the AEO 2007 Reference Case on average over the forecast period as shown in the exhibit below.

Exhibit 2-6. Comparison of Henry Hub Gas Price Forecasts (2007$/MMBtu)



As indicated in Exhibits 2-5 and 2-6, our forecast of the Henry Hub natural gas price is almost $1.00 per MMBtu higher in 2008 than in 2007, and then it declines to the year 2013. The projected "bump" in 2008 and the projected decline thereafter are both driven by the market expectations regarding demand and supply over the next few years.

The higher price in 2008 is a direct reflection of the value that the NYMEX futures market (as of May 2, 2007) placed on Henry Hub gas in 2008 as compared to 2007. The

market's expectations of a higher price for gas deliveries a year in the future has its origin in the effects of Hurricane Katrina, which landed on the Gulf Coast on August 29, 2005 and drove up gas prices in the following months dramatically. Prior to that experience, the NYMEX gas futures "year-out" price was generally the same as the "near-month" price. However, since Katrina, NYMEX year-out prices have been generally higher than near-month prices by about $2.00 per MMBtu in 2006 and $1.00 per MMBtu in 2007.

This price spread is based upon the expectation among gas futures traders that 2008 prices will be higher than 2007 prices for several reasons. The market is expecting continued declines in imports from Canada due to declines in Canadian gas production,[12] interruptions in US production due to an active hurricane season in the Atlantic this summer and fall, increased gas consumption due to higher than normal summer temperatures in the United States and high oil prices, decreases in LNG imports due to increases in demand for LNG in Europe to meet winter demand, and increased US consumption this winter due to a return to average temperatures after the recent warmer than normal winters.

There are several reasons for the decline in the NYMEX gas futures prices for the out years beyond 2008. Some agree with the view of AEO 2007 that gas prices will decline from the near term level due to increasing supply resulting from technological improvements in finding and producing gas in North America. Others may believe that LNG imports will moderate the North American gas price. Finally, futures prices tend to decline in the out years to reflect the risk of holding long positions in gas futures.

C. Forecast of High and Low Gas Prices at the Henry Hub

In this section higher and lower gas price cases are presented. Similar to the base price forecast, these forecasts were derived from various price cases presented in AEO 2007. The volatility of those prices is also discussed.

(a) Higher Price Case

The AESC 2007 higher price case represents a future with the same slow technological progress in finding oil and gas as in the AESC 2007 base forecast, and fewer oil and gas resources than expected in the AEO 2007 reference case. We developed the AESC 2007 higher price case by adding to the prices from the AESC 2007 base forecast a projection of the incremental price impact of a lower projection of natural gas resources. We drew that projected incremental price impact from an analysis of AEO 2007 forecasts for various cases.

In addition to its Reference Case, AEO 2007 presents summary results for 33 additional cases. These cases have widely varying assumptions about economic growth, oil and gas resources, energy efficiency in consuming sectors, and technological development in the various energy supply sectors.[13] The AEO 2007 case which produced the highest oil and

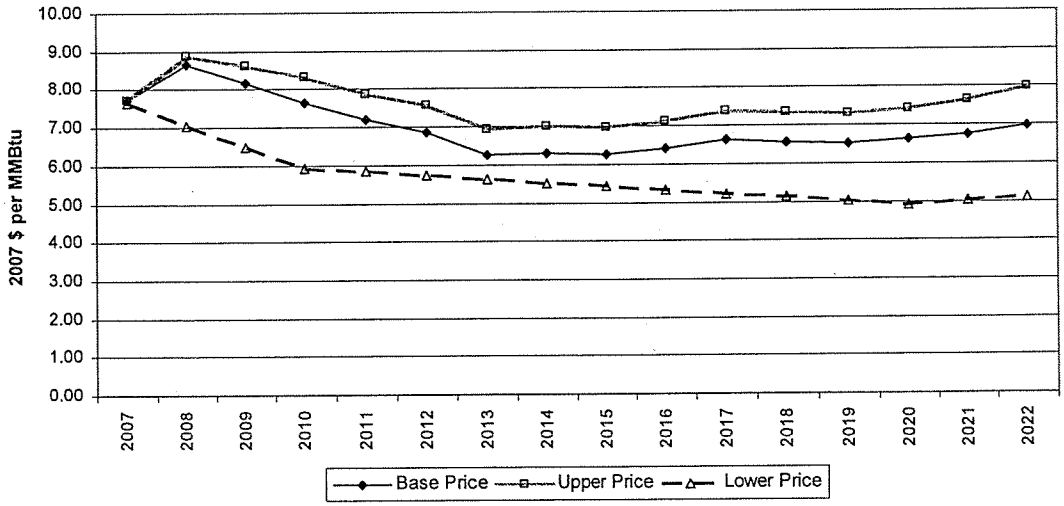
[12] Canada's National Energy Board, "2007 Summer Energy Outlook" expects 2007 gas production in Canada to decline about 500 million cubic feet per day from 2006 production.

[13] AEO 2007 Appendix E, Exhibit E1.

gas prices is called the "high price case". In that case, the quantity of oil and gas resources[14] in the US and worldwide are assumed to be 15 percent less than in the reference case. This assumption produces a crude oil price of $100/bbl in 2030 compared with the Reference Case price of $59/bbl in 2030 (all in 2005$).

The difference between the Henry Hub natural gas price forecast under the AEO 2007 high price case and the AEO 2007 reference case is a measure of the impact of the 15 percent reduction in the available oil and natural gas resources. That difference is $0.63/MMBtu (2005$) in 2010 and $0.75/MMBtu (2005$) in 2020. We used that differential to develop the AESC 2007 higher price case. Specifically, the AESC 2007 higher gas price case equals the AESC 2007 base forecast price in each year plus the difference between the AEO 2007 high price case and reference case in that year. The resulting AESC 2007 higher price forecast is shown in Exhibit 2-7.

Exhibit 2-7. Forecast Range of Average Henry Hub Natural Gas Prices



(b) Lower Price Case

For the AESC 2007 lower price case we use the AEO 2007 "low price case" forecast. That case assumes future levels of oil and natural gas resources 15 percent higher than under the AEO 2007 reference case. In addition to higher levels of oil and gas resources, the AEO 2007 low price case differs from the AESC 2007 base price forecast in that it assumes new oil and gas reserves will be found more easily and at less cost. The AESC 2007 lower price case is also shown in Exhibit 2-7.

D. Representation of Volatility in Gas Commodity Prices

The AESC 2007 natural gas prices forecast (base case, upper case, and lower case) should be viewed as expected average annual prices. In contrast, actual gas prices are

[14] Resources are proved reserves plus potential, possible and speculative resources that are recoverable under adequate economic conditions and current or foreseeable technology.

volatile. Thus, it is reasonable to expect actual prices to vary around these expected annual average prices. The upper and lower price cases are not intended to show the range of volatility of gas prices. Gas prices have changed by a factor of two or more during a year and they can stay above or below the "expected" price for periods longer than a year.

Pindyck argues that oil, coal, and natural gas prices tend to move toward long-run total marginal cost.[15] This behavior is consistent with the forecast of an average price but with the expectation that the actual price will vary around the average price in a random manner with an annual standard deviation of 11% to 14% even while tending to move to the average. However, Pindyck suggests that the movement of oil and gas prices to a long-run marginal cost is slow and can take up to a decade.[16]

Thus, assuming that the AESC 2007 base price forecast is correct, one should expect that the random movements in gas prices could send the gas price above the upper gas price shown in the exhibit above for several months or in some cases for more than a year. For example, in 2015 the base price forecast is $6.25 per MMBtu (in 2007$). A 12% random increase in that year would make the price $7.00, which is slightly greater than the $6.98 in the higher price forecast. Similarly, random movements could result in actual gas prices below the forecast price. Random movements could move prices in different directions from year to year, above and below the prices forecast for those years.

Price spikes are an example of price volatility. From time to time, the daily spot or even the monthly price of natural gas spikes. In New England and in other gas consuming areas there have been daily price spikes during very cold weather. In addition, natural gas prices have increased for longer periods. The recent example of Hurricane Katrina in 2005 is illustrative. Katrina hit the Gulf Coast on August 29, 2005. One month earlier on July 29, 2005 the NYMEX gas futures contract for September 2005 delivery was priced at $7.885 per MMBtu. On December 13, 2005 the NYMEX January 2006 gas futures contract settlement price was $15.378. Six months after Katrina struck the Gulf Coast, that is, on March 1, 2006, the April 2006 gas futures contract was priced at $6.733 per MMBtu. Subsequently 2006 experienced few hurricanes and on September 27, 2006 the October 2006 gas futures contract closed at $4.210 per MMBtu. But these prices were short lived and on March 1, 2007 the April 2007 gas futures contract settled at a price of $7.288. In this example a shock that removed 5 Bcf per day of natural gas supply produced a strong increase in prices, but prices quickly reversed to more typical levels and in less than a year gas futures price fell temporarily to a level less than one-third of the December 2005 peak. Such shocks and gas price volatility should be expected in the future. Nonetheless, the AESC 2007 base gas price forecast should be viewed as an average or expected Henry Hub gas price forecast.

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[15] Robert S. Pindyck, "The Long-Run Evolution of Energy Prices," *The Energy Journal*, Vol. 20, No. 2 pages 1-27 (1999).

[16] Pindyck shows that the random variation is similar to a geometric Brownian motion with an annual standard deviation of 11 to 14 percent for natural gas, but with a slow movement back toward a mean, which is related to the long-run total marginal cost of the resource, pages 24-25 and 6.

An adjustment to the gas price forecast was not developed for price spikes for several reasons. First, there is little, if any, analytical work publicly available on this issue. Second, the prices should be used as the basis for avoided energy supply costs in evaluating the economic value of long-term investments in energy efficiency. It is not anticipated that the levelized price of gas over the long-term, e.g., 10 to 20 years, would be materially different if one estimated increases from an occasional one to three day price spike during a cold snap or even the type of several month gas price increase following Hurricane Katrina in the fall of 2005. Reasonably high gas prices are already being forecast for the future, and it is believed that investment decisions are unlikely to be affected by accounting for price spikes. Moreover, it is also possible that gas prices could fall below the levels of this forecast (a US recession could lead to a drop in natural gas prices).

E. Forecast of Price for Electric Generation in New England

The forecast natural gas prices for electric generation in New England consists of three components. A forecast of the monthly prices at the Henry Hub, a forecast of the "basis" or cost differential between the Henry Hub and New England, and a forecast of the lateral commodity charge for the delivery of the gas from the pipeline pricing point to the generating unit. The derivation of this forecast is outlined below.

i. Monthly Henry Hub Natural Gas Price Forecast

The first step in producing a forecast of monthly gas prices in New England was to translate the annual Henry Hub natural gas price forecast into a monthly Henry Hub natural gas price forecast. The monthly NYMEX actual prices from January 2007 through May 2007 and the forecasted prices from June 2007 through December 2012 were used to develop ratios of the prices in each month of a year to the annual average for that year. These ratios were applied to the forecast of annual prices from 2013 through 2022 to develop forecasts of monthly prices in each of those years.

ii. Monthly New England Regional Natural Gas Price Forecast

The next step was to develop a forecast of the basis, or cost differential, between monthly spot prices at the Henry Hub and monthly spot prices in New England. Monthly spot prices in New England are reported at several points, the most representative of which are Tennessee Gas Pipeline Zone 6 (TGP Z6) and Algonquin Gas Pipeline City Gate (ALG)[17]

For our forecast we assumed that the future regional spot market price in each month of the study period would equal the forecast Henry Hub price each month plus the historical average basis differential. The historical average basis differential is equal to the

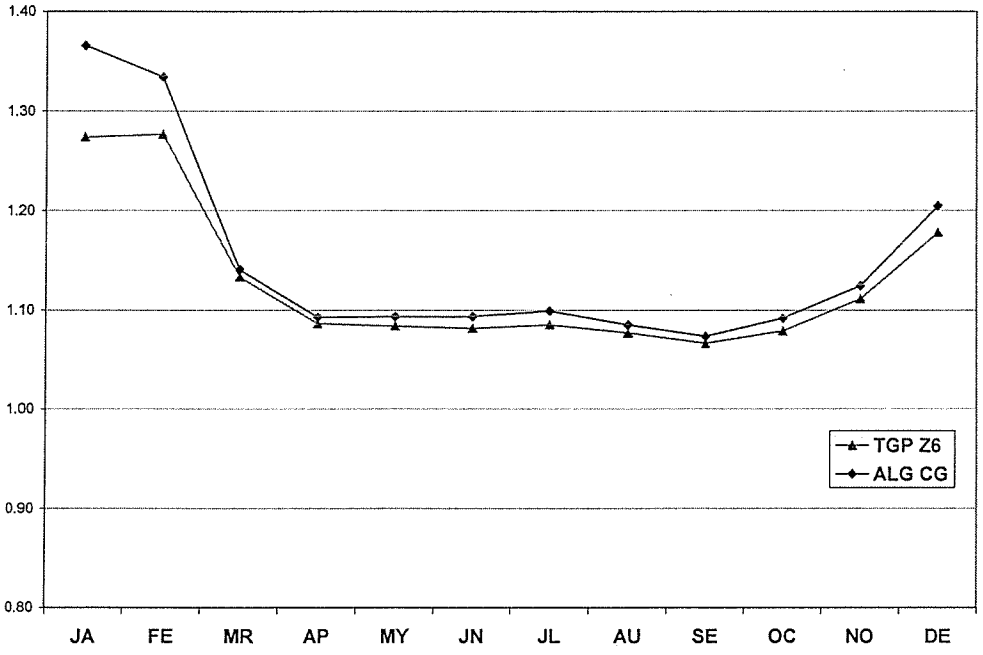
[17] Zone 6 of the Tennessee Gas Pipeline is the section serving New England. Algonquin is a regional pipeline serving New England.

difference between actual monthly Henry Hub natural gas prices and actual monthly regional spot prices as reported at TGP Z6 and ALG respectively.

Our analyses indicate that the historical average basis differential is most accurately represented as a ratio rather than as an absolute differential. Therefore, our forecast of the regional monthly spot prices, with the exception of Vermont, was calculated by taking the average of the forecasts for prices of spot gas delivered from TGP Z6 and ALG.

The average of forecast gas prices for these two zones is appropriate for several reasons. An analysis of spot gas prices delivered from TGP Z6 and ALG between January 2000 and March 2007, presented below, shows no material difference between prices on the two pipelines in most months, which is not surprising. There is ample opportunity for price arbitrage between the two pipelines given the number of interconnections between the two and the number of participants buying and selling gas in the wholesale New England market every day. If the price on these two pipelines diverges by too much, arbitrage would reduce the price difference. In addition, arbitration panels rely upon the average of these two price indices, TGP Z6 and ALG, to represent the market value of gas in New England for purposes of setting prices under gas supply contracts between gas producers and generating units.

Exhibit 2-8. Average Actual Basis Differential Ratios – TGP Z6 vs. ALG



Forecast prices for natural gas for electricity generation in Vermont were not developed because Vermont currently does not have adequate pipeline capacity to support a major gas-fired generating unit. Currently, Vermont Gas receives gas from TransCanada Pipelines at Highgate on the Vermont/Canadian border and distributes that gas to

customers in northern Vermont. It is not connected to the rest of the New England gas pipeline network.

In order to adjust the Henry Hub natural gas prices as accurately as possible, both actual monthly basis differentials (the absolute difference between TGP Z6 and ALG and Henry Hub prices in $/MMBtu) and monthly basis differential ratios (TGP Z6 and ALG versus Henry Hub prices) were calculated over the period January 2000 – March 2007. In the end, the basis differential ratios were utilized instead of the actual monthly basis differentials due to the fact that they were more stable over time. The average monthly basis differential ratios for TGP Z6 and ALG were applied to the monthly forecast of Henry Hub natural gas prices to develop monthly prices for TGP Z6 and TLG over the forecast period.

Despite the fact that a basis differential ratio was used to calculate average monthly basis differentials in AESC 2007 while the actual basis differential was used in AESC 2005, the two approaches were still comparable. The average monthly basis differentials from AESC 2005 were compared to the average monthly basis differentials as calculated from basis differential ratios for AESC 2007 as presented in the exhibit below. The AESC 2007 average monthly basis differentials were substantially higher than the AESC 2005 values in most months. The difference was primarily attributable to the fact that the AESC 2007 forecast of Henry Hub natural gas prices was higher than the AESC 2005 forecast and that the forecast average monthly basis differentials were calculated from a ratio rather than from a single absolute difference applied over the forecast period.

Exhibit 2-9. Comparison of Forecast Average Monthly Basis Differentials for Power Generators (2007$/MMBtu)

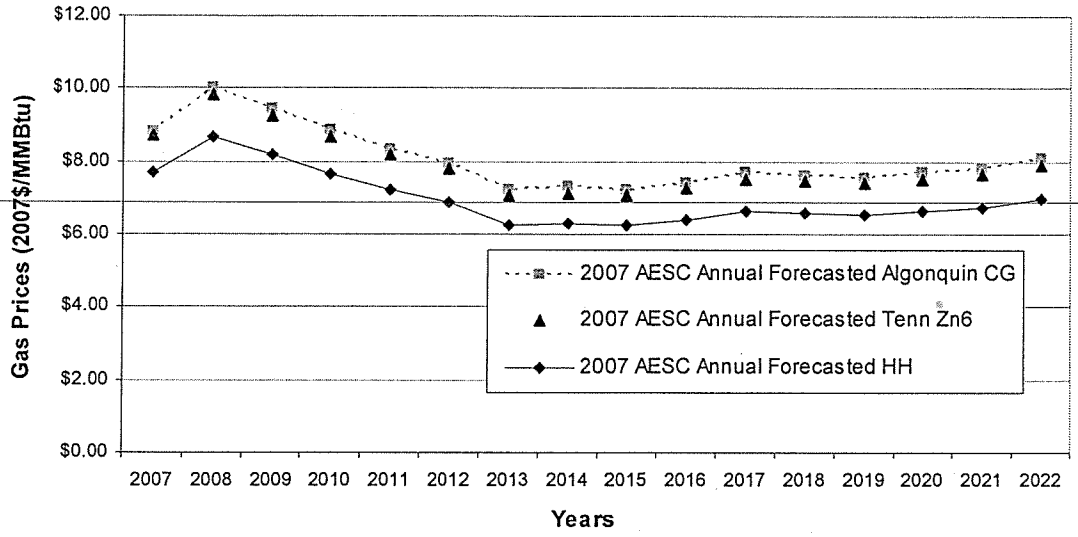
Month	AESC 2005 Southern NE	AESC 2007 (ALG + TGP Z6)/2	AESC 2007 vs AESC 2005	AESC 2005 Central NE	AESC 2007 (ALG + TGP Z6)/2	AESC 2007 vs AESC 2005
1	3.06	2.44	-20%	2.64	2.44	-8%
2	1.38	2.40	74%	1.26	2.40	90%
3	0.81	1.02	26%	0.76	1.02	35%
4	0.53	0.58	10%	0.47	0.58	22%
5	0.43	0.56	31%	0.39	0.56	45%
6	0.37	0.57	54%	0.30	0.57	86%
7	0.42	0.60	44%	0.34	0.60	79%
8	0.39	0.53	38%	0.32	0.53	70%
9	0.33	0.46	43%	0.32	0.46	48%
10	0.39	0.58	48%	0.34	0.58	71%
11	0.53	0.84	60%	0.48	0.84	74%
12	1.20	1.44	20%	0.90	1.44	60%

Lastly, a lateral commodity charge for the delivery of the gas from the pipeline to the generating plant was added to the forecasted regional gas price. ALG has a firm transportation rate schedule, AFT-CL, for laterals that connect ALG's mainline with several electric generating stations and one manufacturing plant. The 100% load factor rates for firm service to the electric generating plants under rate schedule AFT-CL range

in price from $0.0229 to $0.1093 per MMBtu.[18] Considering that the deliveries are likely to be at less than 100 percent load factor, the $0.07 per MMBtu lateral charge used in AESC 2005 was reasonable and was adopted in AESC 2007.

The AESC 2007 Henry Hub annual natural gas price forecast is shown in the exhibit below relative to the ALG annual natural gas price forecast and the TGP Z6 annual natural gas price forecast.

Exhibit 2-10. Henry Hub and New England Natural Gas Price Forecasts (2007$/MMBtu)



The forecasts of monthly prices for natural gas prices at the Henry Hub, ALG, TGP Z6 and for electric generation in New England are presented in Appendix B.

F. Impact of New Regional Supplies on Regional Price of Natural Gas

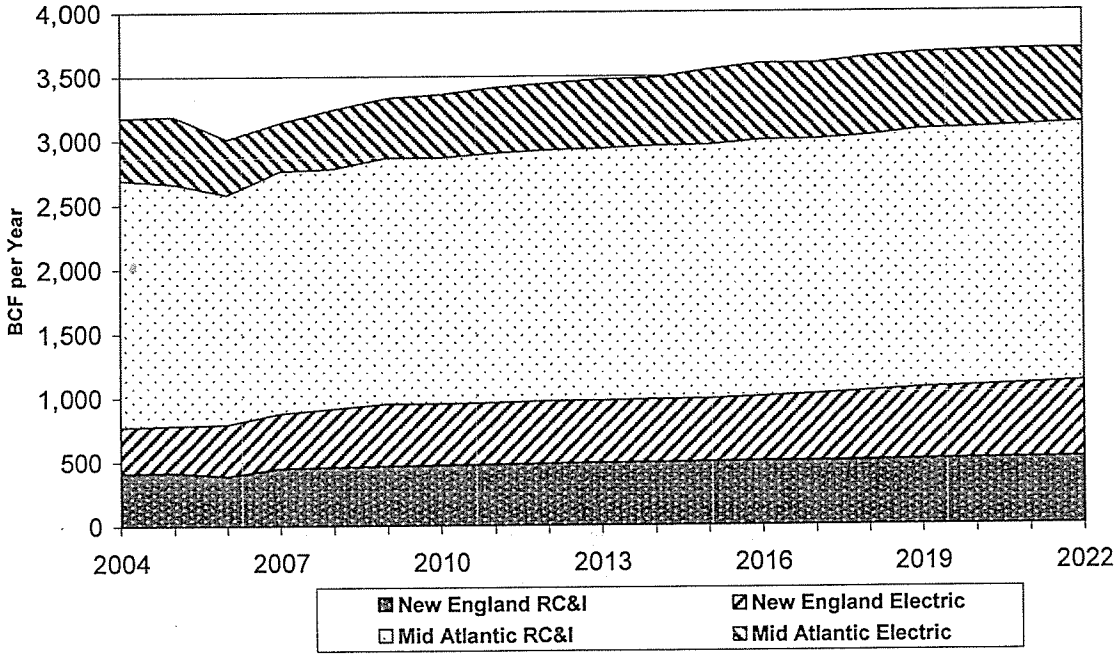
It was thought that the addition of a significant quantity of new supply could put downward pressure on regional prices by reducing the basis differential of New England spot gas prices relative to Mid-Atlantic pricing points such as TETCO M-3.[19] New gas supply is expected to enter New England from one or more of the new LNG import terminals proposed for Massachusetts as well as from Phase IV of the Maritime and Northeast Pipeline. Since Encana has announced plans to develop Deep Panuke off Nova Scotia, and since the Canaport LNG terminal in New Brunswick is under construction, it is expected that additional gas will be delivered to New England through the Maritimes and Northeast pipeline. How many, and which of the other proposed LNG terminals will be completed is uncertain, as is the annual quantity of LNG that will actually be delivered

[18] Algonquin Gas Transmission, LLC, FERC Gas Tariff sheets No. 36 and 37 effective October 1, 2006.

[19] TETCO M3 is Texas Eastern Transmission Company, market zone 3. Zone M3 includes parts of Pennsylvania and ends in New Jersey.

to each terminal.[20] Nevertheless, it is reasonable to expect some additional annual quantity of LNG to be delivered into New England consistent with the national supply assumptions from AEO 2007 presented earlier in Exhibit 2-2. However, these new projects will not necessarily result in a major reduction in regional prices for electric generation in New England, since load is projected to grow in both New England and the Mid-Atlantic, and since the Mid-Atlantic market is several times larger than New England as depicted in Exhibit 2-11.

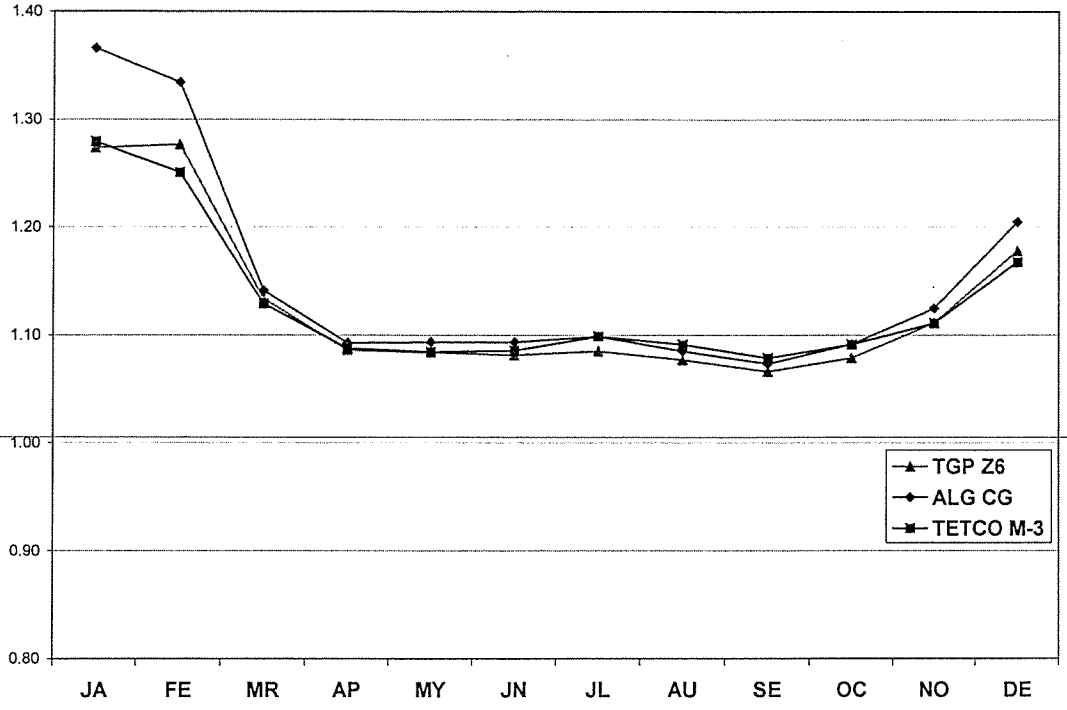
Exhibit 2-11. AEO 2007 Projections of Gas Demand in New England and the Mid-Atlantic (Bcf per year)



Major reductions in regional prices for electric generation in New England are also not anticipated since the average monthly basis differential at TETCO M-3 relative to the Henry Hub natural gas price, measured as a ratio to HH prices, is not materially different from the basis differentials for the corresponding months at the ALG pricing point and is only slightly less than the TGP Z6 pricing point for most months over the past 7 years. On average, the ALG average monthly basis differential ratio relative to Henry Hub is higher than that of TETCO M-3 in the months of January and February. This is not surprising since TETCO M-3 feeds gas into ALG. The surprise is that the New England average monthly basis differential ratio relative to Henry Hub is similar to that of TETCO M-3 in the majority of months.

[20] For a discussion of the near-term LNG market and the difficulty of forecasting LNG imports into the United States see: EIA, "Short-Term Energy Outlook Supplement: U.S. LNG Imports – The Next Wave," January 2007.

Exhibit 2-12. Average Actual Basis Differential Ratios – TGP Z6 vs. ALG vs. TETCO M-3



Further analysis indicates that the minimal average monthly basis differential between New England and the Mid-Atlantic area over the last several years can be explained by increased supply into New England since 2000. Exhibit 2-13 compares the actual annual average of gas imports into New England to the average daily gas consumption in New England during the lowest months of consumption (June through September). As can be seen for the recent past, imports into New England are close to the daily average consumption during June – September. Thus, especially during the summer, there is no need to bring significant gas from the Mid-Atlantic to New England. One would not expect the New England spot price to be much higher than Mid-Atlantic prices under these conditions. This is consistent with the findings concerning the prices in New England and at TETCO M-3 as shown in the figure above.

In order to determine how much of an impact additional supply may have on New England prices, a scenario in which at least one of the three proposed Massachusetts terminals is completed, bringing an additional 0.4 Bcf/day of gas to New England, was analyzed. In this scenario, it was assumed that the existing import pipelines continued to supply gas as they have recently. It was also assumed that 46% of the gas throughput on the Iroquois Pipeline was sent to Connecticut and Massachusetts. This estimate was based upon the fact that in 2007 about 46% of the firm contracts on Iroquois delivered gas to Connecticut and Massachusetts.[21] It was also assumed that gas consumption in

[21] From the Iroquois Pipeline website: www.iroquois.com

New England during June – September would increase through 2010 and 2020 as projected by the AEO 2007. The results of this analysis are shown in the exhibit below.

Exhibit 2-13. Average Annual Gas Imports Entering New England Compared to Average Consumption in Summer (June-September; Bcf per day)

	Actual Average 2004-06	Projection 2010	Projection 2020
Pipeline Supply (a)			
Iroquois Pipeline to NE (c)	0.416	0.391	0.391
PNGTS, Pittsburg, NH	0.070	0.085	0.085
M & N: excluding Canaport LNG	0.296	0.301	0.301
Pipeline Volumes entering NE first	0.782	0.777	0.777
LNG Imports			
Distrigas imports (a)	0.433	0.466	0.466
Canaport Imports to US	0.000	0.500	0.500
One of the proposed Mass. LNG Project Completed	0.000	0.320	0.400
LNG Volumes Entering New England	0.433	1.286	1.366
Total Gas Entering New England First (a)	1.215	2.063	2.143
	2002-06		
New England Gas Consumption June-Sept (b)			
Residential, Commercial & Industrial	0.511	0.590	0.640
Electric Generation	1.140	1.451	1.714
New England Consumption June - Sept	1.651	2.041	2.354

(a) Gas supply projections assume no growth in each supply source. Historical data; EIA Natural Gas Annual 2005 and USDOE Fossil Energy, Natural Gas Import & Export Regulation.
(b) Gas consumption projections based on 2002-06 actuals and growth rates in in EIA Annual Energy Outlook 2007.
(c) Fraction of Iroquois supply to New England is the fraction of firm transportation contracts which deliver to Massachusetts and Connecticut during 2007.

Under these assumptions the projected growth in new supply essentially matches and is offset by the projected growth in demand. There is no major surplus of imports above New England summer gas consumption levels in 2010 or 2020. Consequently, there is no compelling reason to assume that future gas price basis differentials between New England and the Henry Hub would be materially less in the future than they were in the past due to the delivery of additional supply from new LNG terminals proposed for New England and New Brunswick.

To be sure that the impact on pricing is not significant, a second scenario was analyzed where most or all of the proposed Massachusetts LNG terminals came on line. In this event, the sum of pipeline and LNG imports into New England could exceed consumption in New England in summer months. If that were to occur, the excess supply would need to be transported from New England to the Mid-Atlantic either for direct sale or injection into storage. This could cause New England spot gas prices to decline relative to TETCO M-3 prices in those months. However, the decline would likely be on the order of a few percent because rates for pipeline transportation capacity would be discounted in the summer and some transportation would be by backhaul and exchange.

Alternatively, the LNG suppliers might choose not to deliver supplies in excess of New England demand at a price less than TETCO M-3, and instead sell some of that supply in markets with higher prices such as Europe.

G. Forecast of Price for Retail Sectors

i. Cost to Supply Natural Gas to LDCs

New England LDCs use three basic supply resources to meet the sendout requirements of their customers. These resources are (1) gas delivered directly from producing areas via long-haul pipelines, (2) gas withdrawn from underground storage facilities (most of which are located in Pennsylvania) and delivered by pipeline, and (3) gas stored as liquefied natural gas and/or propane in tanks located in the LDC service territories throughout New England.

The cost of gas delivered to an LDC using pipeline transportation and storage facilities consists of four basic components:

- the cost of the gas commodity, which in this study is the forecast price at the Henry Hub in Louisiana;
- the fixed demand cost of holding pipeline transportation capacity and of storage and withdrawal capacity;
- the usage (volumetric) charges for transporting gas on a pipeline and for storage injections and withdrawals; and
- the fraction (percentage) of volumes of gas received by a pipeline or storage facility that is retained by the facility for compressor fuel and losses. This fuel and loss retention increases the cost of gas above the Henry Hub price because more volumes of gas must be purchased at the Henry Hub than is delivered to the LDC. In the analysis that follows, the fuel and loss retention is represented as the ratio of the volumes of gas purchased at the Henry Hub to the volumes of gas delivered to the LDC.

The LDCs generally own the LNG and/or propane tanks and accompanying liquefaction and vaporization facilities. Since the bulk of the New England peak gas supply comes from LNG facilities, AESC 2007 focuses on them although in certain circumstances propane is the dominant peak gas source. The LDC pays for the construction, financing, operation and maintenance of the LNG facility as well as the cost of the gas that is loaded into the tank as LNG.

Because of the significantly increased level of winter season requirements and the variation in winter day requirements according to temperature, LDCs develop a portfolio among the three gas supply resources in order to optimize reliability and cost. Generally, long-haul pipeline transportation is used to meet customer gas requirements each month of the year and to refill underground storage and sometimes LNG tanks during the summer months. Much of the increased winter (November - March) gas demand from customers is met by transporting gas from the underground storage facilities, often

located in Pennsylvania, to the LDC in New England.[22] LNG and propane facilities meet daily peaking and seasonal requirements during the heaviest demand period, December through February.

Of those three resources, only long-haul pipeline transportation capacity is used in multiple applications, i.e., to provide direct supply in winter, to refill underground storage in summer, and to provide direct supply in summer. As a result, in order to determine the avoided cost of reductions in loads in various winter and summer periods, we had to begin by determining how to allocate the demand charges that LDCs incur for that capacity among those multiple applications. Our analysis of the average use of long-haul capacity by LDCs, presented in detail below, indicates that in winter months all of this capacity is used to provide direct supply while in summer months approximately 80% of this capacity is used to provide direct supply and to refill storage. Based upon that analysis, our projections of avoided costs are based upon the following allocations of the demand charges of long-haul pipelines:

- demand charges incurred in winter months are included in the avoided costs of winter months;
- twenty percent of demand charges incurred in summer months are included in the avoided costs of winter months, corresponding to the approximately 20% of physical capacity not being used in the summer either to refill storage or provide direct supply;
- demand charges associated with the quantity of long-haul capacity used to refill underground storage in summer are included in the avoided costs of gas stored underground. (The cost of that stored gas is ultimately included in the avoided costs of winter months);
- demand charges associated with the quantity of long-haul capacity used to provide direct supply in summer are not included in the avoided costs of summer months because our analysis indicates that demand charges for this capacity cannot be avoided.

ii. Sector-Specific Avoided Natural Gas Price Forecast

This section discusses forecasts of the avoided costs of natural gas saved by energy efficiency programs for the period 2007 through 2022 for both (1) gas delivered to New England local distribution companies (LDCs) and (2) the avoided cost of gas at the retail level delivered to end-users of gas. The avoided costs are calculated as a weighted average cost of the marginal natural gas supply sources during specified seasonal and peak-day costing periods.

The avoided cost of gas to an LDC is the cost of the marginal source of supply for the relevant cost period. For this analysis, the long-run avoided cost was estimated because efficiency improvement is a long-term effect that can allow an LDC to avoid both the

[22] LDCs acquire pipeline and storage services through a portfolio of contracts whose terms and conditions are regulated by the Federal Energy Regulatory Commission (FERC).

short-run variable costs and also some, but not all, of the long-term fixed costs of gas supply sources. The marginal cost (avoided cost) was computed for each month and for the peak day. The avoided cost is the cost of delivering one dekatherm of gas to the LDC via the three resources in each month. For each of the winter months, November through March, when gas is supplied by the three resources, the marginal cost is the weighted average of the costs for each supply source depending upon the fraction of total volumes of sendout provided by each source. By computing the weighted average, the approach taken in AESC 2005 was mirrored by assuming that the LDCs have optimized the mix of supply sources and thus both fixed and variable costs are avoided in the mix of all three of the supply sources for a long-term efficiency improvement.[23]

In this forecast, the approach of AESC 2005 was applied in some areas, but not in others. For example, a different approach was taken when computing the avoided cost of each cost period. AESC 2007 estimates the avoided cost for each month and averages the monthly avoided costs.

Similar to AESC 2005, it was assumed that the marginal source of gas to New England LDCs from the Henry Hub is transportation and storage on either of the Tennessee Gas Pipeline (TGP), for LDCs in Northern and Central New England, or the route of Texas Eastern Transmission (TETCO) and Algonquin Gas Transmission (AGT), for LDCs in Southern New England.[24] While proposed LNG receiving and re-gasification terminals in New England and New Brunswick will likely be new gas suppliers to New England, it is not likely that they will establish the avoided cost of gas supply to New England. Rather, the price of gas from these new terminals will be set by the price of gas in New England supplied by TGP and TETCO-ALG.[25]

[23] In a short-run marginal cost analysis only variable costs can be adjusted and thus the avoided cost is determined by the one supply source which has the highest variable cost.

[24] Northern and Central New England is Massachusetts, New Hampshire and Maine; Southern New England is Connecticut and Rhode Island.

[25] Unlike in the past, the Federal Energy Regulatory Commission has decided that LNG terminals will not need to offer open access services and will be able to sell LNG at market prices. In a similar fashion the Maritimes & Northeast pipeline expansion is contracted by Repsol YPF, which is the provider of the LNG to the Canaport LNG terminal in New Brunswick. Thus this LNG will also be sold at market prices in New England.

Exhibit 2-14. Comparison of the Levelized[26] Avoided Costs for LDCs from AESC 2005 and AESC 2007 (2007$/dekatherm[27])

		WINTER				SUMMER				
	Peak Day	3 Months Dec-Feb	5 Months Nov-Mar	6 Months Nov-Apr	7 Months Oct-Apr	5 Months May-Sep	6 Months May-Oct	7 Months Apr-Oct	9 Months Mar-Nov	Annual Average
		Northern and Central New England				Tennessee Gas Pipeline				
AESC 2005 (a)	(b)	10.26	9.15	8.84	8.57	6.79	6.77	6.74	(b)	8.06
AESC 2007	92.72	9.04	8.86	8.56	8.39	7.12	7.16	7.15	7.47	7.86
Percent difference 2005 to 2007	na	-11.9%	-3.2%	-3.1%	-2.1%	4.9%	5.8%	6.1%	na	-2.4%
		Southern New England				Texas Eastern & Algonquin Route				
AESC 2005 (a)	(b)	10.88	9.55	9.18	8.88	6.89	6.87	6.82	(b)	8.12
AESC 2007	110.05	9.41	9.18	8.83	8.63	7.14	7.18	7.17	7.54	8.01
Percent difference 2005 to 2007	na	-13.6%	-3.8%	-3.7%	-2.8%	3.7%	4.6%	5.1%	na	-1.4%

Source of the AESC 2005 levelized cost is Exhibit 1-19 of the AESC 2005 report, page 38.
(a) Factor to convert 2005$ to 2007 $ 1.0547
(b) Levelized costs were not provided in the AESC 2005 report, Exhibit 1-19.
Note: AESC 2005 levelized costs over the years 2005 - 2025. AESC 2007 levelized costs over the years 2007 - 2022.

The winter season avoided costs in AESC 2007 are up to 13% less than in AESC 2005. This is primarily due to differences in the allocation of pipeline demand charges in AESC 2007 as compared to AESC 2005. AESC 2005 allocated all 12 months of pipeline demand costs to the winter cost periods while AESC 2007 did not. In contrast, as described in detail earlier in Section 2.G.i., AESC 2007 effectively allocated 5 winter months of pipeline demand charges, plus the portion of summer month pipeline demand charges not used for direct supply to summer load, to the winter cost periods.

AESC 2007 summer season avoided costs were up to 7% greater than those in AESC 2005, due mostly to the higher forecast Henry Hub gas price in AESC 2007. In Exhibit 2-14, the avoided cost in Southern New England is greater than that in Northern and Central New England due to the greater demand and usage rates of TETCO and AGT relative to those of TGP. Similar to AESC 2005, AESC 2007 does not include an allocation of demand charges of long-haul transportation in the avoided costs for the summer season (April – October).

[26] Costs were levelized over the years 2005 – 2025 in AESC 2005 and the years 2007 – 2022 for AESC 2007.

[27] One dekatherm (DT) is one million BTU.

(a) Representative New England Local Distribution Company

For this avoided cost analysis a representative New England LDC was used to determine the fraction of customer requirements met from each resource each month and the fraction of storage refill in each of the summer months, April through October. The characteristics of a representative New England LDC are shown in the exhibit below.

Exhibit 2-15. Representative New England Local Gas Distribution Company Monthly Characteristics of Send-Out by Source, Peak Month, and Storage Injection

	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Fractions of LDC Send-out by Source Each Month												
Pipeline Deliveries, Long-haul	1.00	1.00	1.00	1.00	0.86	0.64	0.50	0.52	0.68	1.00	1.00	1.00
Underground Storage	0.00	0.00	0.00	0.00	0.11	0.33	0.40	0.39	0.30	0.00	0.00	0.00
LNG and Propane Peaking Supply	0.00	0.00	0.00	0.00	0.03	0.03	0.10	0.09	0.02	0.00	0.00	0.00
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fraction of Annual Sendout each Month	0.032	0.034	0.036	0.062	0.096	0.143	0.174	0.151	0.114	0.077	0.046	0.035
Monthly Sendout as a Fraction of Peak Month	0.184	0.195	0.207	0.356	0.552	0.822	1.000	0.868	0.655	0.443	0.264	0.201
Fraction of Underground Storage Injection by Month	0.170	0.170	0.140	0.100	0.000	0.000	0.000	0.000	0.000	0.080	0.170	0.170

Sources:
(a) Cost of Gas Adjustment filings at Department of Public Utilities for Yankee Gas Systems, Connecticut Natural Gas Company, Bay State Gas Co., NSTAR and KeySpan Energy.

The fractions portraying the representative New England LDC were essentially an average of the data in Cost of Gas Adjustment filings for Yankee Gas Services Company, Connecticut Natural Gas Corporation, Bay State Gas Company, NSTAR Gas Company and Keyspan Energy Delivery in New England.

(b) Avoided Cost of Gas from Each of the Three Sources

As described above, the avoided cost (marginal cost) consisted of the commodity cost of gas, the demand charges of pipeline transportation and storage, the volumetric cash costs of pipeline transportation and storage, and the fuel and loss retention for the various parts of bringing gas to an LDC.

(c) Commodity Cost Inputs

For this avoided cost analysis it was assumed that the marginal cost of the gas commodity was the monthly price of gas at the Henry Hub.

(d) Pipeline Rates

As described above, it was assumed that the marginal source of gas to New England LDCs is transportation and storage on either of TGP or the route of TETCO and AGT. The cost for transportation and underground storage is set by the rates charged by these pipelines and their fuel and loss retention percentages, which are shown in the exhibit below. It was assumed that these rates and retention percentages would persist for the forecast period, 2007 – 2022. This was the same assumption as in AESC 2005.

Exhibit 2-16. Pipeline Rates for Transportation and Storage

	Demand $/DT/month	Usage $/DT	Fuel & Loss (a) Winter %	Fuel & Loss (a) Summer %
Texas Eastern Transmission, L.P. (b)				
Transportation: FT-1, WLA - M3			Dec - Mar	Apr - Nov
WLA-AAB	2.6030			
ELA-AAB	2.1520			
M1 - M3	10.5770			
Total Demand	15.3320			
WLA - M3 usage (c)		0.0590	8.88	7.34
Storage & Transportation: SS-1				
Reservation,	5.6560			
Space ($/DT/year)	0.1293		0.06	0.06
Injection		0.0324	0.89	0.89
Withdrawal (c)		0.0483	3.93	3.42
Algonquin Gas Transmission LLC (d)				
			Dec - Mar	Apr - Nov
Transportation: AFT-1 (FT-1,WS-1)	6.5854			
Usage (c)		0.0128	1.37	0.66
Tennessee Gas Pipeline Company (e)				
			Nov - Mar	Apr - Oct
Transportation FT-A				
Zone 1 (LA) to 6	15.15	0.1503	7.82	6.67
Zone 1 (LA) to 4	10.77	0.1014	5.90	5.06
Zone 4 to 6	5.89	0.0834	2.17	1.92
Storage FS - Market Area				
Reservation	1.15			
Space	0.0185			
Injection		0.0102	1.49	1.49
Withdrawal		0.0102		

Sources and Notes:
(a) Fuel and loss is applied to volumes received.
(b) FT-1: Tariff Sheet Nos. 30 & 31 effective February 1, 2007 and Sheet Nos. 126 & 127 effective December 1, SS-1: Tariff SheetNo. 52 effective February 1, 2007 and Sheet Nos. 126 & 127 effective December 1, 2006.
(c) Includes ACA charge of $0.0016 per DT, which are included in TGP listed rates.
(d) AFT-1: Tariff Sheet No. 22 effective October 1, 2006.
(e) FT-A: Tariff Sheet Nos. 23 effective July 1, 2006, Sheet No. 23A effective October 1, 2006 and Sheet No. 29 effective March 1, 1997; FS: Sheet No. 27 effective July 1, 2006.

(e) Long-haul Pipeline "Cash" Costs

Gas is delivered to the LDC each month by pipelines from producing areas, in this analysis assumed to be the Henry Hub.[28] "Cash cost" means the avoided cost of transportation arising from pipeline usage charges, which are paid for each dekatherm of gas transported, and the demand charges allocated to that month, which pay for the reservation of pipeline capacity whether used or not. The avoided commodity cost of gas purchased was the price of gas at the Henry Hub that month multiplied by the ratio of the

[28] Rate schedules assumed for the long-haul transportation: TETCO, FT-1 from zone WLA to zone M3; AGT, AFT-1 (FT-1) and TGP, FT-A from zone 1 to zone 6.

Henry Hub volume purchased to one dekatherm of gas delivered to the LDC. Because of the retention of gas for fuel and loss in both transportation and storage, more than one dekatherm of gas must be purchased at the Henry Hub in order to deliver one dekatherm to the LDC.

This ratio of gas volumes purchased at the Henry Hub to one dekatherm of gas delivered to the LDC was established by the fuel and loss retention percentages of the various pipeline transportation and storage services used between the Henry Hub and the LDC. For example, assume that the gas is transported by two pipelines: A and B from the Henry Hub to the LDC. The fuel and loss percentage is 6% for A (Fa) and 4 percent for pipeline B (Fb). The fuel and loss amount taken by the pipeline is based on the volumes received by the pipeline (R) while the demand and usage charges are based on the volume of gas delivered by the pipeline (D). In order to compute the ratio of gas received to that delivered the following equations were used:

(1) $D = R - FR$

(2) $D = R(1-F)$

(3) $R/D = 1/(1-F)$

For pipeline A; $Ra/Da = 1/(1-.06) = 1.0638$; or $Ra = 1.0638\ Da$

For pipeline B; $Rb/Db = 1/(1-.04) = 1.0417$; or $Rb = 1.0417\ Db$

Since Db is the amount delivered to the LDC, Ra/Db or the ratio of the amount to be purchased in the field to the amount delivered to the LDC is what needs to be computed.

Since: $Rb = Da$

$Ra = 1.0638\ Da = (1.0638)Rb = (1.0638)(1.0417)Db$

Thus: $Ra/Db = (1.0638)(1.0417) = 1.1082$

Or: 1.1082 DT of natural gas must be purchased for each DT delivered.

The exhibit shows the avoided costs by gas source and pipeline route.

Exhibit 2-17. Comparison of Avoided Costs of Delivering One Dekatherm of Gas to a New England Local Distribution Company from Three Sources of Natural Gas and Peak Day

		Texas Eastern & Algonquin		Tennessee Gas Pipeline	
		January	June	January	June
	units				
Pipeline Long-haul to LDC					
Total Demand Cost of Gas Delivered to LDC	2007 $/DT	$0.98	$0.00	$0.67	$0.00
Total Usage Cash Cost of Gas delivered to LDC	2007 $/DT	$0.07	$0.07	$0.15	$0.15
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.113	1.086	1.085	1.071
Delivered From Underground Storage					
Total Demand Cost of Gas Delivered to LDC from UG Storage	2007 $/DT	$1.39		$1.16	
Total Cash cost for refill + Usage Cost of Gas delivered to LDC	2007 $/DT	$0.83		$0.80	
Ratio of Gas Purchased to Gas Delivered to LDC		1.149		1.093	
LNG Regasified into LDC System					
Total Demand Cost of Gas Delivered to LDC for LNG refill	2007 $/DT	$0.90		$0.62	
Total Usage Cash Cost of Gas delivered to LDC for LNG refill	2007 $/DT	$0.09		$0.19	
Ratio of Gas Purchased at HH to Regasified Gas at the LDC		1.349		1.331	
Peak Day in January From Underground Storage					
Pipeline Cash Demand Cost of Gas Delivered to LDC	2007 $/DT	$101.73		$84.79	
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2007 $/DT	$0.83		$0.80	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.149		1.093	

Based on pipeline rates effective April 25, 2007

AESC 2007 computed the demand cost of long-haul transportation differently from AESC 2005 in the winter period. For the summer period, April – October, AESC 2007 had a similar assumption to AESC 2005, but a different result due to differing implementation of the assumption. This difference in assumptions is explained in the next section.

(f) Summer

AESC 2005 assigned no demand charges to the avoided cost during the summer periods (5, 6, 7 and 9 months) based upon an assumption that the market value of pipeline capacity release in the summer would be zero. AESC 2007 also assumed that the value of pipeline capacity release is zero in the summer, but only for the months of April – October, which is a seven month period. The assumption that demand charges cannot be avoided in the summer was supported by the basis differentials in the summer between the Henry Hub and either the ALG gas spot market or the TGP Z6 spot gas market. The basis differential for each market was enough to cover the usage charges and fuel, but there was little or no amount remaining to pay for demand charges. This means that an LDC would continue to pay the full demand charge in each summer month even if the gas requirements of customers were reduced due to energy efficiency in the summer; thus the LDC would not avoid the summer pipeline demand charges.

AESC 2005 and AESC 2007 were in agreement that there is no avoided cost of long-haul pipeline transportation for the 7-month summer period of April – October. This forecast differs in that AESC 2005 allocated no demand costs to the months of November and March for the 9-month summer period of March – November. In contrast, AESC 2007 considered November and March part of the winter period and did allocate demand charges to those two months as described in the next section.

LDCs use their long-haul pipeline transportation in the summer to fill underground, and sometimes LNG storage. Thus, some long-haul pipeline capacity is needed and used in the summer in addition the direct transportation to the LDC from the Henry Hub. Consequently, in AESC 2007 the costs of demand and usage charges and the fuel and loss fraction for pipeline transportation from the Henry Hub to refill storage were allocated to the avoided cost of underground storage.

(g) Winter

AESC 2005 assumed that the full twelve months of pipeline demand charges were assigned to each of the winter periods (3, 5, 6 and 7 months). Thus, saving a dekatherm each day of a 3-month winter period allows a reduction of twelve months of long-haul demand charges, and reducing one dekatherm per month over five months reduced twelve months of demand charges, etc. It was believed that the AESC 2005 assumption was aggressive since long-haul pipeline transportation is used throughout the year, in part for storage fill.

Based on the typical New England LDC send-out and storage refill shown in Exhibit 2-15, approximately 20% of the long-haul pipeline capacity used in the winter period was not used either for direct transportation to the LDC or for storage refill during the seven-month summer period. The pipeline transportation demand charges during the summer for this 20% of unused capacity were allocated to the winter period in order to calculate avoided costs in AESC 2007.

The use of the long-haul transportation capacity in the winter varies from about 85% in February and March to 100% in December. In AESC 2007, the pipeline transportation demand charges, including the 20% from summer demand charges, were allocated to each of the five winter months according to the use of the capacity by month. As a result, the avoided transportation demand cost varied among the five winter months with the month of heaviest use, December, receiving the largest allocation of demand charges.

(h) Underground Storage

Natural gas is delivered to the LDC from underground storage during the five winter months of November through March as shown in Exhibit 2-15. For both TETCO and TGP, the underground storage is located in Pennsylvania. The avoided cost of underground storage supply for one dekatherm in January is shown in Exhibit 2-17.

The avoided cost of underground storage included the cost of buying gas at the Henry Hub, pipeline demand and usage charges to bring gas to the storage facility, the cost of injection, the demand cost of storage capacity, the demand and variable costs of withdrawing gas from storage and the demand and variable costs of transporting gas to the LDC from underground storage.[29]

[29] Rate schedules used in the calculation for the TETCO-AGT route are: TETCO, FT-1 zone WLA to zone M3; storage on TETCO and transportation to AGT, SS-1; and transportation to the LDC on AGT, AFT-1 (WS-1). Rate schedules used in the Tennessee route are: TGP, FT-A zone 1 to zone 4; storage on TGP, FS – market area; and transportation to the LDC on TGP, FT-A zone 4 to zone 6.

The cost of gas injected into storage was the cost of buying gas at the Henry Hub, as adjusted for fuel and loss retention, plus the cost of transportation to underground storage including both demand and usage costs at 100% load factor. The cost of the gas injected into storage was less than the average cost of gas for a year, 0.937 of the annual cost, because gas is purchased for injection during the summer months when the price of gas is less than average.

Pipelines bill LDCs demand charges for the capacity LDCs hold for withdrawal of gas from storage and transportation to the LDC every month of the year. Therefore, in this study we allocated a full year of withdrawal and transportation demand charges to the five winter months.[30] These annual demand charges were allocated among each of the five winter months according to the relative quantity of capacity the LDC used in each month. As shown in Exhibit 2-15, January is the peak send-out month; the other winter months, especially November and March, experience less send-out. Thus, the demand cost of unused capacity of storage withdrawal and of transportation capacity from underground storage to the LDC in November and March was assigned to the sendout during December through February based on usage each month. Similarly, the unused capacity during December and February was assigned to the cost of withdrawing and transporting gas to the LDC in January.

(i) LNG Peak Shaving

There are 46 liquefied natural gas (LNG) tanks in New England in addition to the Distrigas LNG import terminal. These tanks, and to a lesser extent propane, provide peak shaving supply for LDCs. The peak shaving avoided costs are based only on LNG in AESC 2007. These facilities have fixed and variable costs. The estimate of avoided costs was based on the variable costs only.

The major embedded or accounting costs of LNG send-out for peaking service are the fixed costs of building the tank, vaporization and liquefaction capacity, and the fixed costs of operation and maintenance. However, these fixed costs are likely to be unaffected by reductions in gas demand due to modest-sized efficiency improvement measures. These fixed costs are sunk costs. Moreover, LNG peaking facilities have strong economies of scale and thus are lumpy investments. They are likely to be sized to accommodate growth in gas send-out. In addition, the cost of changing the capacity of send-out is the cost of vaporization facilities, which is a small portion of the total fixed costs of the LNG peaking facility. Thus, it was assumed that the avoided cost of LNG peaking facilities due to efficiency improvements should ignore these fixed costs.

The avoided costs of LNG peaking are the variable costs of the LNG; the cost of gas at the Henry Hub, costs of pipeline transport to bring gas to the LNG facility, including

[30] This is true of the storage and delivery service of TETCO in rate schedule SS-1 as well at withdrawal from storage and transportation to the LDC on TGP. However, AGT has a winter service, WS, firm transportation from the interconnection with TETCO to New England LDCs which has demand charges for only the five winter months. AESC 2007 reflected AGT's five months of demand charges in its allocation and calculation.

pipeline demand charges,[31] and then the variable costs of liquefaction and re-gasification.[32] The variable costs of liquefaction and vaporization are principally the gas that is used in the liquefaction stage and the vaporization stage. It was assumed that fuel use is 17% for liquefaction and 3% for vaporization.

The estimated avoided cost of LNG peaking service is shown in Exhibit 2-17. The avoided cost of LNG peaking service was materially different, much smaller, from that of AESC 2005, which spread the cost of 12 month storage service at the Distrigas LNG facility over the various winter periods. However, Distrigas no longer offers open access LNG storage service, and a public tariff and accompanying rates are not currently available.

(j) Peak-Day Avoided Cost

LNG peaking facilities are generally used to meet the peak-day requirements of a New England LDC. The fixed costs were excluded from the estimate of the avoided costs for the LNG facilities. This modest cost, which excludes fixed costs, did not properly capture the high avoided costs that were expected for peak day service.

Consequently, peak-day avoided costs were estimated based on the costs of underground storage. It was assumed that underground storage and transportation capacity to the LDC was needed to meet a one-day peak even though the demand charges are generally paid for 12 months.[33] Thus, in calculating the peak-day avoided cost, the demand charges for all 12 months were allocated to the one-day peak. The estimate of peak-day avoided costs is shown in Exhibit 2-17 for both the TETCO-ALG and the TGP routes.

An alternative estimate of the avoided cost of natural gas on a peak-day to a New England LDC is the spot market price of natural gas in New England on a peak day. The largest peak-day sendout in New England for the eight years prior to 2007 occurred on January 15, 2004.[34] During that day the spot price of gas in ALG was $63.42 per dekatherm, and the spot price at TGP Z6 was $49.81 per dekatherm.

The peak-day avoided cost estimates in AESC 2007 for Southern New England and Northern and Central New England were slightly less than one-half of the peak-day avoided cost estimates in AESC 2005.[35] AESC 2005 did not specify how the peak-day avoided cost was calculated. However, the spot gas prices in New England for the highest peak-day of the last 8 years supported the estimates of AESC 2007.

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[31] Rate schedules used for the long-haul transportation of gas in the summer to be liquefied are the same as those cited for long-haul transportation: TETCO, FT-1 from zones WLA to zone M3; AGT, AFT-1 (FT-1) and TGP, FT-A from zone 1 to zone 6.

[32] LDC LNG tanks are also filled by hauling imported LNG from the Distrigas facility to the LNG tank by tanker truck. However, we assume that Distrigas will price this LNG at the LDC's avoided cost of liquefaction.

[33] In the case of transportation of stored gas to New England on AGT, a winter service is used for which demand charges are paid for only the five-month winter period.

[34] NEGA Statistics 2006, page 59.

[35] AESC 2005 Exhibits 1-15 and 1-16, pages 35 and 36.

(k) Avoided Cost Forecast by Seasonal Cost Periods

In this step, the avoided costs of natural gas were determined by costing period in two of the three geographic areas: Northern and Central New England (Massachusetts, New Hampshire and Maine) and Southern New England (Connecticut and Rhode Island). The avoided cost forecast for Vermont is presented later in this section. The avoided cost of natural gas by costing period was calculated as the average of the avoided cost in each of the months that comprise the costing period. As described earlier, the avoided cost in any month was calculated as the weighted average of the avoided cost of gas delivered to the LDC from each of the three sources: long-haul pipeline, underground storage, and LNG storage.

The weightings each month are shown in Exhibit 2-15 above.[36]

As was done in AESC 2005, it was assumed that the avoided cost in Southern New England was the cost of gas delivered to LDCs by the Texas Eastern and Algonquin pipeline route. Similarly, it was assumed that the avoided cost of gas delivered to LDCs in Northern and Central New England was provided by Tennessee Gas Pipeline.

The avoided cost forecast by seasonal cost periods for Southern New England is shown in Exhibit 2-18. Also shown is the annual Henry Hub forecast price of natural gas. Other than for the peak-day, the commodity cost of gas based on the Henry Hub price was the largest component of the avoided cost.

Similarly, Exhibit 2-19 shows the avoided cost of natural gas delivered to LDCs in Northern and Central New England via the Tennessee Gas Pipeline.

[36] The summer periods all fall within a single calendar year; thus, the commodity cost of gas is based on the Henry Hub price for that calendar year. However, the winter periods span calendar years. The majority of gas delivered in the winter is from LNG and underground storage, which was purchased during the previous summer. Thus, we assume that the commodity cost of gas is based on the Henry Hub price from the year in which the winter delivery period begins.

Exhibit 2-18. Avoided Costs of Gas Delivered to LDCs via Texas Eastern and ALG Pipelines by Season and Cost Period (2007$/dekatherm)

		WINTER				SUMMER					
Year	Peak Day	3 Months Dec-Feb	5 Months Nov-Mar	6 Months Nov-Apr	7 Months Oct-Apr	5 Months May-Sep	6 Months May-Oct	7 Months Apr-Oct	9 Months Mar-Nov	Annual Average	Annual Henry Hub Price
2007	110.87	10.28	10.05	9.68	9.47	7.91	7.95	7.94	8.33	8.82	7.71
2008	111.88	11.37	11.13	10.74	10.51	8.86	8.91	8.90	9.31	9.82	8.65
2009	111.35	10.80	10.56	10.18	9.97	8.36	8.41	8.39	8.80	9.30	8.16
2010	110.79	10.20	9.97	9.60	9.39	7.84	7.88	7.87	8.26	8.74	7.65
2011	110.31	9.68	9.46	9.10	8.89	7.38	7.43	7.41	7.79	8.26	7.20
2012	109.95	9.29	9.07	8.72	8.52	7.04	7.08	7.07	7.44	7.90	6.86
2013	109.28	8.58	8.36	8.02	7.83	6.41	6.45	6.44	6.79	7.24	6.24
2014	109.34	8.64	8.42	8.09	7.89	6.47	6.51	6.50	6.85	7.30	6.30
2015	109.29	8.59	8.37	8.04	7.84	6.42	6.46	6.45	6.80	7.25	6.25
2016	109.44	8.75	8.53	8.19	7.99	6.56	6.60	6.59	6.95	7.40	6.39
2017	109.70	9.03	8.81	8.47	8.27	6.81	6.85	6.84	7.20	7.66	6.64
2018	109.62	8.94	8.72	8.38	8.18	6.73	6.77	6.76	7.12	7.58	6.56
2019	109.58	8.89	8.67	8.33	8.13	6.69	6.73	6.72	7.08	7.53	6.52
2020	109.70	9.03	8.81	8.47	8.26	6.81	6.85	6.84	7.20	7.66	6.63
2021	109.81	9.15	8.92	8.58	8.38	6.91	6.95	6.94	7.31	7.77	6.73
2022	110.08	9.43	9.21	8.86	8.65	7.16	7.21	7.19	7.57	8.03	6.98
Levelized 2008-22 (a)	110.055	9.408	9.183	8.833	8.628	7.141	7.184	7.170	7.543	8.009	6.961

(a) Real (constant $) riskless annual rate of return in %: 2.2165%

Exhibit 2-19. Avoided Costs of Gas Delivered to LDCs via TGP Pipeline by Season and Cost Period (2007$/dekatherm)

		WINTER				SUMMER					
Year	Peak Day	3 Months Dec-Feb	5 Months Nov-Mar	6 Months Nov-Apr	7 Months Oct-Apr	5 Months May-Sep	6 Months May-Oct	7 Months Apr-Oct	9 Months Mar-Nov	Annual Average	Annual Henry Hub Price
2007	93.49	9.89	9.71	9.40	9.22	7.88	7.92	7.91	8.25	8.66	7.71
2008	94.45	10.96	10.77	10.44	10.25	8.82	8.87	8.85	9.22	9.65	8.65
2009	93.95	10.40	10.22	9.89	9.71	8.32	8.37	8.36	8.71	9.13	8.16
2010	93.42	9.81	9.64	9.32	9.15	7.81	7.86	7.84	8.18	8.59	7.65
2011	92.96	9.31	9.13	8.83	8.65	7.36	7.40	7.39	7.72	8.12	7.20
2012	92.62	8.92	8.75	8.45	8.28	7.02	7.06	7.05	7.37	7.76	6.86
2013	91.98	8.22	8.05	7.77	7.60	6.40	6.44	6.43	6.73	7.10	6.24
2014	92.04	8.28	8.11	7.83	7.67	6.46	6.50	6.49	6.79	7.16	6.30
2015	91.99	8.23	8.06	7.78	7.62	6.41	6.45	6.44	6.74	7.12	6.25
2016	92.13	8.39	8.22	7.93	7.77	6.55	6.59	6.58	6.88	7.26	6.39
2017	92.39	8.67	8.49	8.20	8.04	6.80	6.84	6.82	7.14	7.52	6.64
2018	92.31	8.58	8.41	8.12	7.95	6.72	6.76	6.75	7.06	7.44	6.56
2019	92.26	8.53	8.36	8.07	7.91	6.68	6.72	6.70	7.01	7.39	6.52
2020	92.38	8.67	8.49	8.20	8.03	6.80	6.84	6.82	7.14	7.52	6.63
2021	92.49	8.78	8.61	8.31	8.15	6.90	6.94	6.92	7.24	7.62	6.73
2022	92.74	9.06	8.89	8.59	8.42	7.14	7.19	7.17	7.50	7.89	6.98
Levelized 2008-22 (a)	92.719	9.036	8.862	8.563	8.393	7.122	7.165	7.151	7.473	7.864	6.961

(a) Real (constant $) riskless annual rate of return in %: 2.2165%

The levelized avoided cost is the cost for which the present value at the real riskless rate of return of 2.2165 percent has the same present value as the estimated avoided costs for the years 2007 through 2022 at the same rate of return.

(l) Comparison with the AESC 2005 Avoided Cost Calculations for an LDC

Compared to the results of AESC 2005, the avoided cost projections in Exhibits 2-18 and 2-19 are generally higher for the summer periods. This is primarily due to higher projections of Henry Hub prices in AESC 2007 compared to AESC 2005.[37] For the winter periods, the avoided cost estimates are somewhat lower than those in AESC 2005 because less of the summer period (April – October) demand charges were allocated to the winter period (November – March) avoided costs. In AESC 2007, 20% of the summer period pipeline transportation demand charges are allocated to the winter period transportation avoided costs. This allocation corresponds to the fact that, in the summer, 80% of pipeline capacity is used for long-haul transportation to the LDC or to refill storage and the 20% unused capacity is paid for to be available for winter period transportation. In contrast, AESC 2005 allocated twelve months of long-haul pipeline transportation demand charges (that is, 100% of the summer period demand costs and in the case of the 3-month, December – February, cost period, 100% of the November and March pipeline demand costs were also allocated to it) to each of the winter cost periods in computing avoided long-haul transportation costs.

Exhibit 2-20 compares the avoided cost estimates for the three sources of natural gas used by AESC 2005 and AESC 2007: pipeline long-haul, underground storage, and LNG peaking supply during the three-month winter period (December – February) as well as peak day supply. This comparison is for the pipeline route of TETCO and AGT. However, the comparison of avoided cost estimates along the TGP route would provide similar qualitative comparisons.

[37] See AESC 2005 Exhibit 1-15 to compare with Exhibit 2-18 for the TETCO AGT route and AESC 2005 Exhibit 1-16 to compare with Exhibit 2-19 for the TGP route.

Exhibit 2-20. Comparison of AESC 2005 and AESC 2007 Costs of Delivering One Dekatherm of Gas to a New England Local Distribution Company via the TETCO – ALG Route December-February from Three Sources of Natural Gas and Peak Day

	units	AESC 2005	AESC 2007
Pipeline Long-haul to LDC			
Pipeline Demand Cost	2007$/DT	$2.772	$0.866
Pipeline Variable Cash Cost	2007$/DT	$0.096	$0.072
Ratio of Gas Purchased at HH to Gas Delivered	fraction	1.095	1.113
Delivered From Underground Storage			
Pipeline Demand Cost	2007$/DT	$0.886	$0.953
Pipeline Variable Cash Cost (a)	2007$/DT	$0.000	$0.832
Ratio of Gas Purchased at HH to Gas Delivered	fraction	1.000	1.149
LNG Regasified into LDC System			
Pipeline Demand Cost	2007$/DT	$8.693	
Pipeline Variable Cash Cost (a)	2007$/DT	$0.000	$0.899
Ratio of Gas Purchased at HH to Gas Delivered	fraction	1.000	1.349
Peak Day			
Pipeline Demand Cost	2007$/DT	$260.521	$101.727
Pipeline Variable Cash Cost (a)	2007$/DT		$0.832
Ratio of Gas Purchased at HH to Gas Delivered	fraction		1.149

Source: AESC 2005 TETCO and AGT charges taken from Exhibit 1-14a, Monthly Pipeline Costs, page 34.
AESC 2005 peak day costs from Exhibit 1-15, page 35.
Note: Conversion from 2004$ and 2005$ to 2007$ used conversion factors of 1.0867 and 1.0547 respectively.
Note: Ratio of gas purchased at Henry Hub to Gas Delivered to the LDC for AESC 2005 is the stated fuel and loss retention plus one (1), which is consistent with the calculations in the AESC 2005 worksheets.
(a) In AESC 2007 the pipeline variable cash costs include pipeline demand charges for refill of storage, but not the demand cost for delivery to the LDC from underground storage.

AESC 2005 estimated the demand cost of long-haul pipeline transportation at more than three times that shown for AESC 2007, due, as mentioned above, to the allocation of twelve months of demand charges to the cost period. However, AESC 2007 had a higher fuel and loss retention ratio.

The AESC 2005 underground storage cost estimates were much lower because they did not fully include the cost of transportation to and from underground storage. Similarly, AESC 2005 had no fuel retention for underground storage on TETCO while AESC 2007 had a large fuel and loss retention due to including transportation and the compounding effect upon total fuel and loss retention of the gas moving from one rate schedule to another as it is transported to and from storage and also injected and withdrawn from underground storage.

The cost estimate for LNG peaking in AESC 2007 was much lower than that in AESC 2005 because AESC 2007 only considered the variable costs of LDC LNG facilities as being avoidable and AESC 2005 used a tariff of Distrigas LNG storage as the basis of its estimate. However, Distrigas no longer offers any open access LNG storage service with a published tariff.

Finally, AESC 2007 presented an avoided cost estimate of peak-day gas supply which is about one-half that in AESC 2005.

(m) Avoided Costs by End-Use

The avoided costs to LDCs by seasonal costing periods have been presented in Exhibits 2-18 and 2-19. The avoided costs by end-use were developed from those LDC avoided

costs, by applying them to the appropriate end-use profiles and adding an avoided distribution margin. Exhibit 2-21 shows the "cross walk" of end uses to the LDC seasonal cost periods.

Exhibit 2-21. End-Use Consumption Avoidable Cost Cross Walk

End-Use Types	Period	Months
Commercial and Industrial, non-heating	Annual	Jan – Dec
Commercial and industrial, heating	5 month	Nov – Mar
Existing residential heating	3 month	Dec – Feb
New residential heating	5 month	Nov – Mar
Residential domestic hot water	Annual	Jan – Dec
All commercial and industrial	6 month	Nov – Apr
All residential	6 month	Nov – Apr
All retail end uses	5 month	Nov – Mar

This cross walk exhibit is the same as presented in AESC 2005. There may be a difference in the way the 6-month winter period was defined. The AESC 2005 report did not specify the months of each of its winter periods; however, it was confirmed that the 6-month period in AESC 2005 was October through March. This analysis followed the approach of specifying each of the winter periods as including the coldest months in that period or the months of highest gas send-out. In New England, April is a colder month than October as measured by heating degree-days and April has a greater send-out than October. Consequently, April was included and October was excluded in the 6-month winter period in the AESC 2007 analyses.

(n) Avoided Gas Costs for Each End Use Sector

The Scope of Work for this project specifies that the sponsoring gas utilities will provide distribution charges applicable from the city gate to the burner tip to be added to the LDC avoided costs to compute the end-use avoided costs.

Some LDCs in New England have performed studies of incremental costs, that is, the cost of distribution which is incurred as demand increases. The conclusion was that the incremental cost of distribution was approximately one-half of the embedded cost. This was the same assumption employed in AESC 2005. As in AESC 2005, the embedded cost was measured as the difference between the city-gate price of gas in a state and the price charged each of the different retail customer types: residential, commercial and industrial.[38]

[38] The city-gate gas prices and the prices charged to each retail customer type are reported by the Energy Information Administration for each state each year.

Exhibit 2-22 shows the estimated avoidable LDC costs, measured as 2007$ per dekatherm, by each of the customer end-use types and combination of types listed in the exhibit above.

Exhibit 2-22. Estimated Avoidable LDC Margins 2001-2005 Average (2007$/dekatherm)

	Southern NE	Northern and Central NE
Average City Gate 2001-05	7.82	8.05
Ave. Residential Margin	6.28	5.98
Avoidable	**3.14**	**2.99**
Ave. Commercial Margin	3.08	4.46
Avoidable	**1.54**	**2.23**
Ave. Industrial Margin	0.70	3.20
Avoidable	**0.35**	**1.60**
Ave. Commercial and Industrial	2.21	3.83
Avoidable	**1.11**	**1.92**
All retail avoidable margin	**2.00**	**2.41**

Exhibit 2-23 shows the total avoided costs by the various retail end-use types and combination of types for Southern New England. The avoided cost for each retail end-use type is the sum of the avoided cost of gas delivered to an LDC for the cost period associated with the end-use type plus the avoided LDC margin for the associated end-use type as shown in the exhibit above.

Exhibit 2-23. Avoided Costs of Gas Delivered to Retail Customers in Southern New England via Texas Eastern and ALG Pipelines by End Use (2007$/dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
Year	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.	5-mon.
2007	13.42	13.19	11.96	12.82	9.92	11.16	10.79	12.04
2008	14.51	14.27	12.96	13.88	10.93	12.23	11.84	13.12
2009	13.94	13.70	12.44	13.32	10.40	11.67	11.29	12.56
2010	13.34	13.11	11.88	12.74	9.85	11.08	10.71	11.97
2011	12.82	12.60	11.40	12.24	9.37	10.56	10.21	11.45
2012	12.43	12.21	11.04	11.86	9.01	10.17	9.83	11.06
2013	11.71	11.50	10.38	11.16	8.34	9.46	9.13	10.35
2014	11.78	11.56	10.44	11.23	8.41	9.53	9.20	10.42
2015	11.73	11.51	10.39	11.18	8.36	9.48	9.14	10.37
2016	11.89	11.67	10.53	11.33	8.50	9.63	9.30	10.52
2017	12.17	11.95	10.80	11.61	8.77	9.92	9.57	10.81
2018	12.08	11.86	10.72	11.52	8.69	9.83	9.49	10.72
2019	12.03	11.81	10.67	11.47	8.64	9.78	9.44	10.67
2020	12.17	11.95	10.80	11.61	8.76	9.91	9.57	10.80
2021	12.29	12.06	10.91	11.72	8.87	10.03	9.69	10.92
2022	12.57	12.35	11.17	12.00	9.14	10.32	9.97	11.20
Levelized 2008-22 (a)	12.547	12.322	11.148	11.973	9.115	10.290	9.940	11.179

(a) Real (constant $) riskless annual rate of return in %: 2.2165%

Exhibit 2-24 shows the total avoided cost by the various retail end-use types for Northern and Central New England. The avoided cost is the sum of the avoided cost of gas

delivered to an LDC in Northern and Central New England plus the associated avoided LDC margin shown in Exhibit 2-22 above.

Exhibit 2-24. Avoided Costs of Gas Delivered to Retail Customers in Northern & Central New England via the TGP Pipeline by End Use (2007$/dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
Year	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.	5-mon.
2007	12.88	12.71	11.65	12.39	10.58	11.63	11.32	12.12
2008	13.95	13.77	12.65	13.43	11.57	12.69	12.35	13.18
2009	13.39	13.21	12.13	12.88	11.05	12.14	11.81	12.63
2010	12.81	12.63	11.58	12.31	10.51	11.55	11.24	12.04
2011	12.30	12.12	11.11	11.82	10.03	11.05	10.74	11.54
2012	11.92	11.74	10.75	11.44	9.68	10.67	10.37	11.16
2013	11.21	11.04	10.10	10.76	9.02	9.97	9.68	10.46
2014	11.28	11.11	10.16	10.82	9.08	10.03	9.75	10.52
2015	11.23	11.06	10.11	10.77	9.03	9.98	9.70	10.47
2016	11.38	11.21	10.25	10.92	9.18	10.13	9.85	10.62
2017	11.66	11.49	10.51	11.20	9.44	10.41	10.12	10.90
2018	11.57	11.40	10.43	11.11	9.36	10.33	10.04	10.82
2019	11.52	11.35	10.39	11.06	9.31	10.28	9.99	10.77
2020	11.66	11.49	10.51	11.19	9.44	10.41	10.12	10.90
2021	11.77	11.60	10.62	11.30	9.54	10.52	10.23	11.01
2022	12.05	11.88	10.88	11.58	9.80	10.81	10.51	11.30
Levelized 2008-22 (a)	12.029	11.855	10.856	11.555	9.781	10.780	10.480	11.270

(a) Real (constant $) riskless annual rate of return in %: 2.2165%

iii. Avoided Gas Costs in Vermont

There is one LDC in Vermont, Vermont Gas Systems (VGS), and it receives its gas from TransCanada Pipeline at Highgate Springs, VT. The analysis of the avoided cost to the LDC in Vermont was performed similarly to the analysis above. Based on a Purchased Gas Adjustment (PGA) filing by VGS for the year April 2007 to March 2008, the source of gas was determined for each month of the year by the fraction contribution each month. Next, the marginal cost of natural gas to VGS by source for each month the source is in operation was computed, and then volume weighted average cost was computed by month and by specified cost period.

Each month, Vermont receives gas purchased in Alberta by TransCanada Pipeline. During the winter months, November through March, Vermont also receives gas from underground storage and about 20% from purchases in spot markets.

Since this avoided cost forecast was based on a forecast price of gas at the Henry Hub in Louisiana, the basis differential (price of gas in Alberta at the AECO hub minus the price at the Henry Hub) was taken from the NYMEX futures market for the next two years.[39] NYMEX shows a constant basis differential for the winter, November through March, and a different but constant basis differential for the summer, April through October. The

[39] NYMEX settlements for May 18, 2007 using basis data from the period November 2007 through October 2009.

average ratio of the Alberta gas price to the Henry Hub price is 0.851 for the winter and 0.895 for the summer.

The pipeline transportation rates, rates for underground storage and transporting gas to VGS from underground storage, which are used in the avoided cost forecasts, are shown in the exhibit below. It was assumed that these rates would prevail throughout the forecast period.

Exhibit 2-25. Canadian Tolls Paid by Vermont Gas Systems (US 2007$)

	Demand (a) $/DT/Month	Usage $/DT		Fuel & Loss percent	
Firm Transportation					
Long-Haul	$26.7991	$0.0670	(b)	5.00%	(c)
From Storage	$6.6080	$0.0130	(b)	1.00%	(c)
Storage					
Injection		$0.0058	(d)	0.60%	(d)
Space	$0.0403				
Withdrawal	$4.7789	$0.0058	(d)	0.60%	(d)

(a) Imputed from Vermont Gas Systems PGA filing
(b) TransCanada Approved Tolls effective April 1, 2007
(c) TransCanada Website; estimated. Fuel is actual and changes each month.
(d) Union Gas Rate M12 effective January 1, 2007.
Note: US$/DT is calculated as .96116 of CD$/GJ

Based on the VGS PGA filing, as in other New England LDCs, long-haul transportation is used at about 80 percent load factor in the summer months for refilling underground storage and direct deliveries of gas to VGS. Thus, 20% of summer pipeline demand charges are allocated to the winter long-haul pipeline transportation avoidable costs. The costs of underground storage include the costs of transportation of gas to fill storage, the cost of storage, and the cost of transportation from storage to VGS. However, according to the PGA filing, demand charges are paid 12 months a year for the storage withdrawal capacity and transportation from storage to VGS, which are the same assumptions used for both TETCO and TGP. (Transportation of stored gas from the terminus of TETCO to LDCs on AGT uses winter service which has only 5 months of demand charges.) Purchases of gas in the spot market make up slightly more than 20% of the Vermont winter gas supply. The prices of these spot purchases were estimated by the ratio of the estimated spot price for the October 2007 – March 2008 winter months to the 2007 annual Henry Hub gas price. The components of the avoided costs by the three sources of gas to Vermont are shown in Exhibit 2-26.

Exhibit 2-26. Comparison of Costs of Delivering One Dekatherm of Gas to Vermont Gas Systems from Three Sources of Natural Gas and Peak Day

		TransCanada Pipeline	
		January	June
	units		
Pipeline Long-haul to LDC			
Pipeline DemandCost of Gas Delivered to LDC	2007 $/DT	$1.13	$0.00
Pipeline Usage Cost	2008 $/DT	$0.07	$0.07
Ratio of Gas Purchased in Alberta to Gas Delivered to LDC		1.053	1.053
Delivered From Underground Storage			
Pipeline Demand Cost of Gas Delivered to LDC	2007 $/DT	$1.98	
Pipeline Commocity Cost of Gas Delivered to LDC		$1.49	
Ratio of Gas Purchased to Gas Delivered to LDC		1.076	
Spot Purchases of Gas based on 2007 Henry Hub Price	2007$/DT	$9.49	
Peak Day in January From Underground Storage			
Pipeline Cash Demand Cost of Gas Delivered to LDC	2007 $/DT	$137.22	
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2007 $/DT	$1.49	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.076	

Based on pipeline rates effective April 1, 2007
Note: Fuel and Loss retention is estimated as an annual average.

AESC 2007 then estimated the avoided cost of natural gas delivered to VGS by month for the forecast period and summarized the avoided costs by cost period and year as shown in Exhibit 2-27.

Exhibit 2-27. Avoided Costs of Gas Delivered to Vermont LDC via the TransCanada Pipeline by Season and Cost Period (2007$/dekatherm)

	WINTER					SUMMER					
Year	Peak Day	3 Months Dec-Feb	5 Months Nov-Mar	6 Months Nov-Apr	7 Months Oct-Apr	5 Months May-Sep	6 Months May-Oct	7 Months Apr-Oct	9 Months Mar-Nov	Annual Average	Annual Henry Hub Price
2007	145.66	9.25	9.01	8.64	8.42	6.86	6.90	6.89	7.28	7.77	7.71
2008	146.50	10.20	9.95	9.56	9.33	7.69	7.73	7.72	8.13	8.65	8.65
2009	146.06	9.70	9.46	9.08	8.86	7.25	7.30	7.28	7.68	8.19	8.16
2010	145.59	9.18	8.94	8.57	8.36	6.80	6.84	6.83	7.22	7.71	7.65
2011	145.19	8.73	8.49	8.14	7.92	6.41	6.44	6.43	6.81	7.29	7.20
2012	144.89	8.39	8.16	7.81	7.60	6.11	6.14	6.13	6.50	6.98	6.86
2013	144.33	7.76	7.54	7.20	7.00	5.56	5.60	5.59	5.94	6.40	6.24
2014	144.38	7.82	7.59	7.26	7.05	5.61	5.65	5.64	6.00	6.45	6.30
2015	144.34	7.78	7.55	7.21	7.01	5.57	5.61	5.60	5.95	6.41	6.25
2016	144.46	7.91	7.68	7.35	7.14	5.69	5.73	5.72	6.08	6.54	6.39
2017	144.68	8.16	7.93	7.59	7.38	5.91	5.94	5.93	6.30	6.77	6.64
2018	144.62	8.08	7.86	7.51	7.30	5.84	5.88	5.87	6.23	6.70	6.56
2019	144.58	8.04	7.81	7.47	7.26	5.80	5.84	5.83	6.19	6.65	6.52
2020	144.68	8.16	7.93	7.58	7.38	5.91	5.94	5.93	6.30	6.76	6.63
2021	144.77	8.26	8.03	7.68	7.47	6.00	6.03	6.02	6.39	6.86	6.73
2022	145.00	8.51	8.28	7.93	7.71	6.22	6.25	6.24	6.62	7.09	6.98
Levelized (a)	145.03	8.55	8.31	7.96	7.75	6.24	6.28	6.27	6.65	7.12	7.02

(a) Real (constant $) riskless annual rate of return in %: 2.2165%

As in the other LDCs of New England, the avoided retail cost of gas was also estimated for VGS. The retail avoided cost is the LDC avoided cost plus the LDC avoided margin. As in the other LDCs, the LDC avoided margin was estimated as one-half the embedded LDC cost as shown in Exhibit 2-28.

Exhibit 2-28. Estimated Avoidable LDC Margins for Vermont 2001-2005 Average (2007$/dekatherm)

Average City Gate 2001-05	5.80
Ave. Residential Margin	5.78
Avoidable	**2.89**
Ave. Commercial Margin	3.37
Avoidable	**1.68**
Ave. Industrial Margin	0.23
Avoidable	**0.11**
Ave. Commercial and Industrial	1.77
Avoidable	**0.88**
All retail avoidable margin	**1.64**

The avoided costs to the specified retail customer types are shown in Exhibit 2-29.

Exhibit 2-29. Avoided Costs of Gas Delivered to Retail Customers in Vermont via the TransCanada Pipeline by End Use (2007$/dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
Year	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.	5-mon.
2007	12.14	11.90	10.66	11.53	8.65	9.89	9.52	10.65
2008	13.09	12.84	11.54	12.45	9.53	10.83	10.44	11.58
2009	12.59	12.35	11.08	11.97	9.07	10.34	9.96	11.09
2010	12.07	11.83	10.60	11.47	8.59	9.82	9.46	10.58
2011	11.62	11.38	10.18	11.03	8.17	9.38	9.02	10.13
2012	11.28	11.05	9.87	10.70	7.86	9.04	8.69	9.79
2013	10.65	10.43	9.29	10.09	7.28	8.42	8.08	9.17
2014	10.71	10.49	9.34	10.15	7.33	8.48	8.14	9.23
2015	10.67	10.44	9.30	10.10	7.29	8.43	8.10	9.19
2016	10.80	10.58	9.43	10.24	7.42	8.57	8.23	9.32
2017	11.05	10.82	9.66	10.48	7.65	8.81	8.47	9.57
2018	10.98	10.75	9.59	10.40	7.58	8.74	8.40	9.49
2019	10.93	10.70	9.55	10.36	7.54	8.69	8.35	9.45
2020	11.05	10.82	9.66	10.48	7.65	8.81	8.47	9.57
2021	11.15	10.92	9.75	10.57	7.74	8.91	8.57	9.67
2022	11.40	11.17	9.98	10.82	7.97	9.16	8.81	9.92
Levelized (a)	11.44	11.20	10.01	10.85	8.00	9.19	8.84	9.95

(a) Real (constant $) riskless annual rate of return in %: 2.2165%

The levelized avoided retail costs in Vermont for AESC 2005 and AESC 2007 are compared in Exhibit 2-30. AESC 2005 did not present the avoided gas costs to the LDC

in Vermont or the LDC margins. Thus, a detailed explanation of the differences of the two forecasts is difficult. Two possible differences are: (1) the more detailed, and probably higher, pipeline transportation and storage cost estimates in AESC 2007 compared with AESC 2005 and (2) what may be quite different estimates of LDC margins.

Exhibit 2-30. Comparison of AESC 2005 and AESC 2007 Levelized Avoided Costs of Gas Delivered to Retail Customers in Vermont by End Use (2007$/dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.	5-mon.
AESC 2005 (a)	$9.78	$9.70	$9.62	$9.70	$8.53	$8.62	$8.57	$9.20
AESC 2007	$11.44	$11.20	$10.01	$10.85	$8.00	$9.19	$8.84	$9.95
Percent difference 2005 to 2007	17.0%	15.4%	4.1%	11.8%	-6.2%	6.7%	3.1%	8.2%

Source of AESC 2005 levelized retail avoided costs is Exhibit ES-3, page 5, for 15 years levelized.
(a) Factor to convert 2005$ to 2007 $ 1.0547
Note: AESC 2005 levelized costs for 15 years, 2005 - 2019. AESC 2007 levelized costs for 16 years, 2007 - 2022.

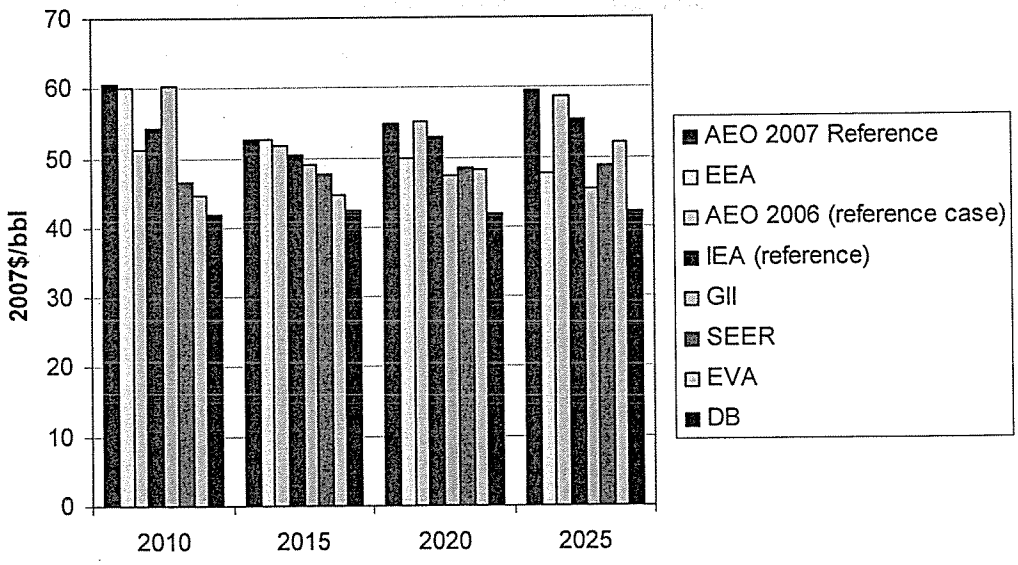
3. Crude Oil Price Forecast

This Chapter provides a projection of crude oil prices.

A. Methodology & Assumptions

The starting point for the crude oil price forecast was the Reference Case forecast in the Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO 2007). The exhibit below shows that the AEO 2007 Reference Case forecast of low sulfur light crude oil prices through 2020 is close to, but slightly higher than, the projections from a number of other sources. Due to expectations of continued growth in world oil consumption and projected continuation of high costs of developing new reserves, the AEO 2007 Reference Case forecast of crude oil provides a good starting point for this forecast.

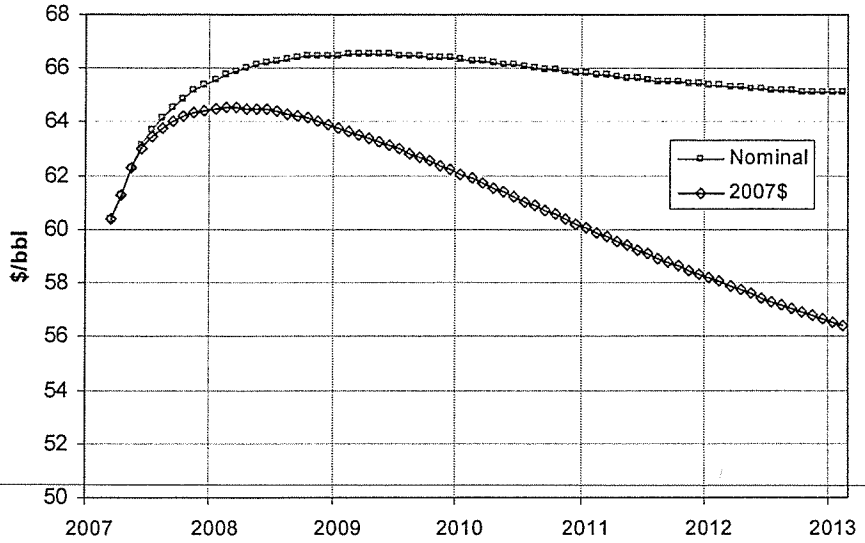
Exhibit 3-1. World Crude Oil Price Forecasts (2007$/bbl)[40]



As a first step, the AEO 2007 near term prices were compared with those from the futures markets. West Texas Intermediate (WTI) crude was the futures price that was used since it is actively traded and the price in the past has been very close to that of the low-sulfur light crude used in the AEO 2007 Reference Case. The futures prices were very stable in nominal dollars for 2008 through 2012 at around $66/bbl, as shown in the exhibit below.

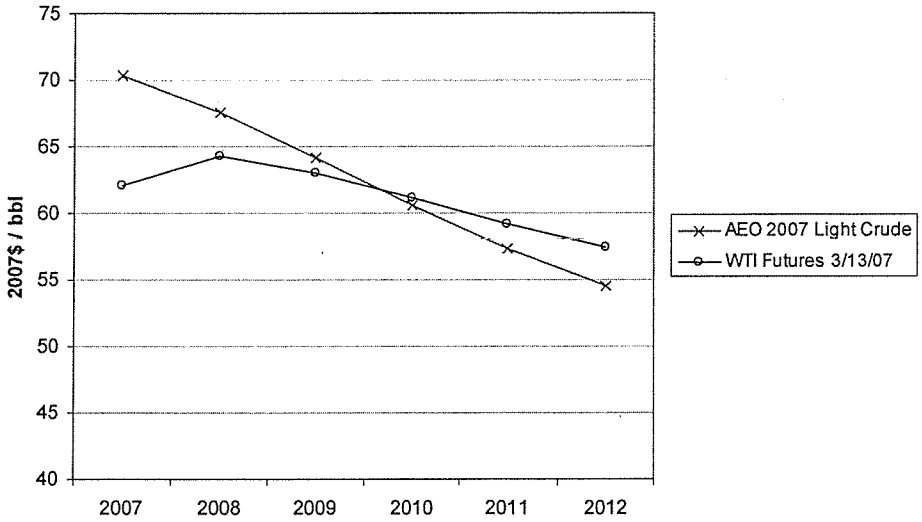
[40] Data provided in AEO 2007, Table 19, page 106; found at: http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2007).pdf, EEA refers to Energy and Environmental Analysis, Inc., IEA refers to the International Energy Agency, GII refers to Global Insights, Inc., SEER refers to Strategic Energy and Economic Research, Inc., EVA refers to Energy Ventures Analysis, Inc., and DB refers to Deutsche Bank AG.

Exhibit 3-2. West Texas Intermediate (WTI) Crude Future Swap Prices (2007$/bbl)



By comparison, the AEO 2007 oil forecast prices for 2007 through 2009 were 14% to 3% higher than the equivalent futures prices as of mid-March 2007, as presented in the exhibit below.[41] This discrepancy was attributable to changes in the market perspectives between late 2006, when the AEO 2007 analysis was prepared, and the current outlook for crude oil.

Exhibit 3-3. Oil Price Forecast Comparison (2007$/bbl)



Taking this discrepancy into account, the AESC 2007 forecast of crude oil prices reflects futures prices in the short term (2007-2012) and the AEO 2007 forecast in the long-term

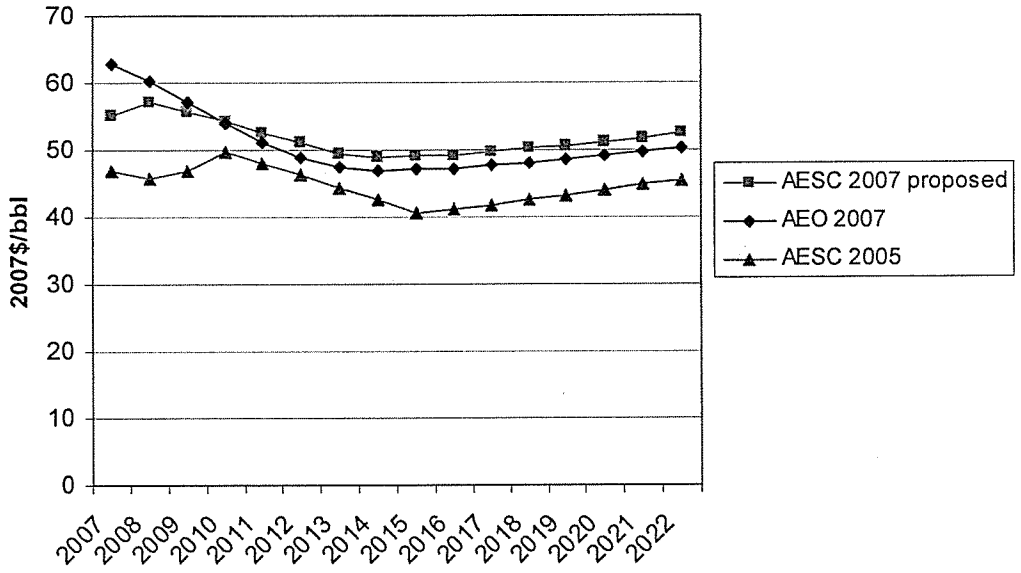
[41] NYMEX ClearPort market prices as of March 13, 2007.

(2013-2022). As with the natural gas forecast, it was reasonable to adjust the near term forecast to represent current market conditions, but for the longer term use one more based on fundamentals. This adjustment followed the futures prices out through 2012[42] which were above the AEO price, and then followed the trend of the AEO forecast.

B. Results

The graph below presents the crude oil price forecast relative to the AEO 2007 Reference Case forecast and to the AESC 2005 forecast. Both the AESC 2005 and the AESC 2007 forecasts are at a low point around 2015 and rise slowly thereafter.

Exhibit 3-4. Price Forecast of Imported Crude Oil Price (2007$/bbl)



[42] As of early July 2007 the futures prices for crude oil were somewhat higher than the March 13 prices used to develop the AESC 2007 crude oil forecast, but not sufficiently different to warrant modifying it.

4. Forecasts of Other Fuel Prices

This chapter provides a projection of fuel prices for electric generation as well as for retail end-use sector.

A. Methodology & Assumptions

The starting point for the forecasts of other types of fuel oil, coal, and fuel wood prices was the Reference Case forecast in the Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO 2007). The Reference Case forecast of AEO 2007 provides forecasts for prices of residual fuel, distillate fuel, and coal used to generate electricity in New England. This forecast also provides projections of petroleum product prices for the residential, commercial and industrial sectors in New England.

The AESC 2007 forecasts of petroleum product prices were derived by adjusting the AEO petroleum product prices in proportion to the difference between the AEO crude oil and the AESC 2007 crude oil forecasts. This adjustment was made because petroleum product prices strongly reflect underlying crude oil prices. The AEO coal price forecasts were not adjusted.

To identify locational differences we analyzed the actual prices by sector by state from 1970 through 2004, which was the most recent historical data available from the EIA State Energy Data System (SEDS).[43] SEDS is the most complete and consistent source of state-level energy prices. This review did not show consistent price differences between states for most products. There were two possible exceptions. One was for distillate fuel in New Hampshire, which for the last ten years has been about 6% below the New England average. The other was for residential prices for LPG which has been about 10% below the New England average for New Hampshire & Vermont, whereas for Rhode Island they have been about 15% above the average.

For commercial and industrial users the differences are much smaller and vary positive and negative from year to year. For years before 1995, the residential price differences between states were negligible and the relative rankings varied from year to year. Thus, the more recent retail locational price differences appear to be related to changes in the markups associated with competitive factors in the residential marketing and distribution systems in the various states. These differentials may or may not persist in the future. For this study, it was assumed that because of fundamentals, the end-use prices for all petroleum products across New England will be roughly the same. Thus, a single New England price by sector for the various oil-based products was recommended.[44]

The SEDS data for the five years 1999-2003 was also used to analyze the markups between petroleum product prices and crude oil prices. This analysis showed that the

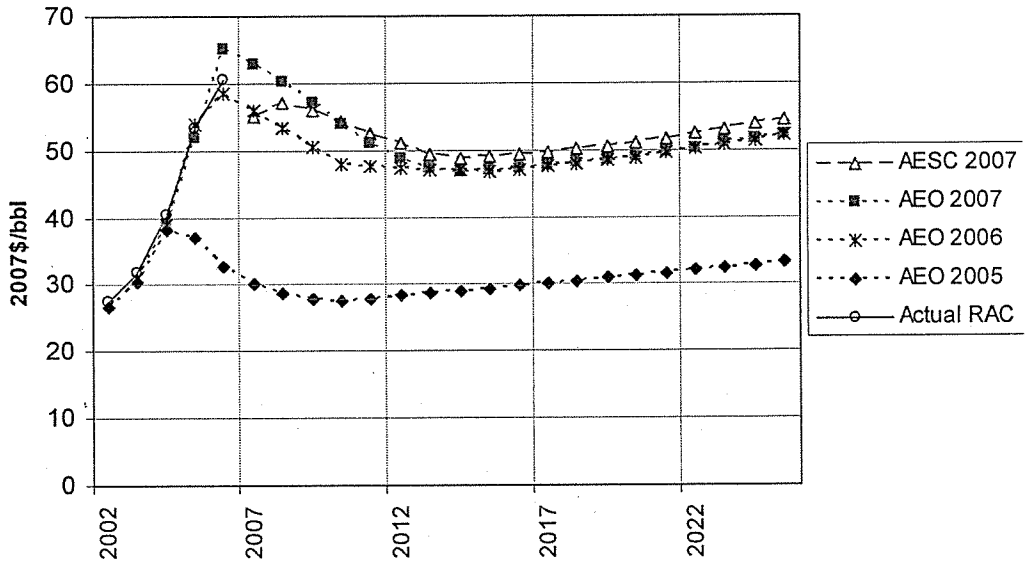
[43] http://www.eia.doe.gov/emeu/states/_seds.html

[44] The AESC 2005 report had no differences in LPG costs between parts of New England. That report did have differences in distillate oil prices that are not reflected in our analysis of the historic data.

markups had both fixed and variable components. However, the underlying crude oil prices (in real terms) for the forecast period are about twice the historic ones. Therefore, caution is appropriate when extending historic markups from a limited period to a longer future period with much higher base prices. Thus for the AESC forecasts, the AEO product versus crude markup ratios were used to calculate future petroleum product prices relative to the cost of crude oil.

EIA forecasts have reflected the recent sharp increase in oil prices.[45] For example, the forecasts of oil prices in 2020 increased by 54% from 2005 to 2006, but are essentially unchanged in the latest AEO. These forecasts along with the actual Refiners Acquisition Cost (RAC) for 2002 through 2006 are shown in the figure below. Note the AEO 2007 estimate for 2006 was a little above the actual RAC.

Exhibit 4-1. Crude Oil Price Forecast Comparisons (2007$/bbl)



Since crude oil prices do not show a monthly/seasonal variation but rather reflect the world market, neither monthly nor seasonal price variations for petrolcum products were developed. Seasonal demand for petroleum products is fairly predictable and storage for petroleum products is relatively inexpensive, which tends to smooth out variations in costs relative to market prices. Price variations can also be hedged with futures contracts and the like.

i. No. 6 Residual Fuel Oil Price Forecast

The AEO price forecast for residual oil was half the price of crude oil on a per Btu basis. While residual oil, especially high sulfur, typically sells below the price of crude oil, a

[45] Crude oil products were not defined the same way in the four studies, but we have adjusted them to be comparable. AEO 2005 reported the World Oil Price. The AEO 2007 nearest equivalent was called Imported Crude Oil. The AESC 2007 price represents a conversion to the AEO 2007 Imported Crude equivalent. The AESC 2005 price was identified as the Refiners Acquisition Cost (RAC).

50% differential was not supported by any available market data. In looking at the historic ratio of residual oil to crude oil prices for the period 1992 through 2006, the high sulfur residual ratio is closer to 70%. Therefore, the price of residual oil for electric generation was calculated based on the historic price ratio.

ii. No. 2 Distillate Fuel Oil Price Forecast

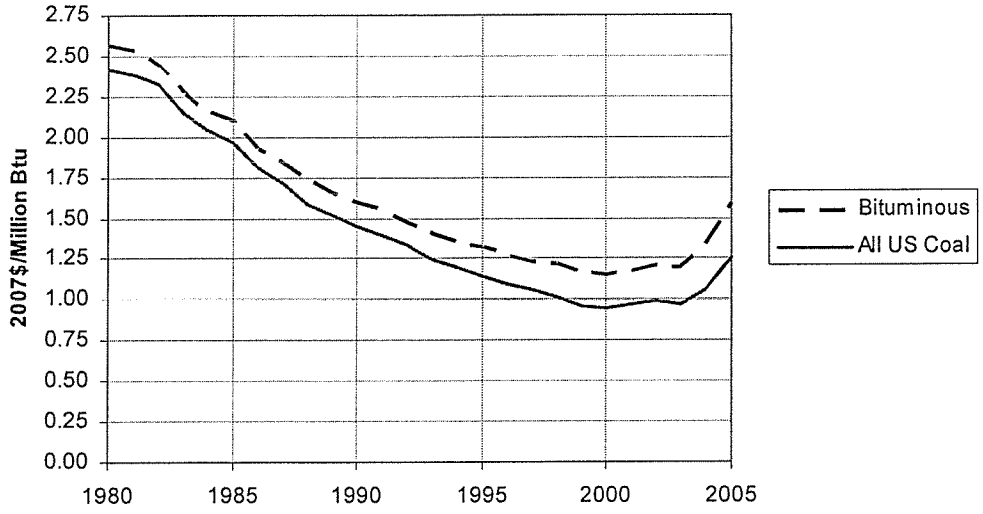
The AEO forecast price for distillate fuel falls below the forecast price for crude oil in about 2015. This was not credible. Therefore, a price for distillate oil was developed based on its recent historic ratio to the crude oil price.

iii. Coal Price Forecast

The AEO 2007 Reference Case forecasts fairly flat prices for coal in New England with a slight decline after 2010. This was determined to be a reasonable forecast. The United States has substantial coal resources and coal prices have been relatively stable over a long time period without the volatility seen in oil and natural gas prices.

Although coal prices tend to be fairly stable now, they have changed in the past. On a real dollar basis, coal prices declined by 50% from 1980 to 2000 as shown in the exhibit below. This mainly reflects various technical efficiencies in coal mining operations and a shift to western coals.

Exhibit 4-2. Historic Coal Prices (2007$/MMBtu)

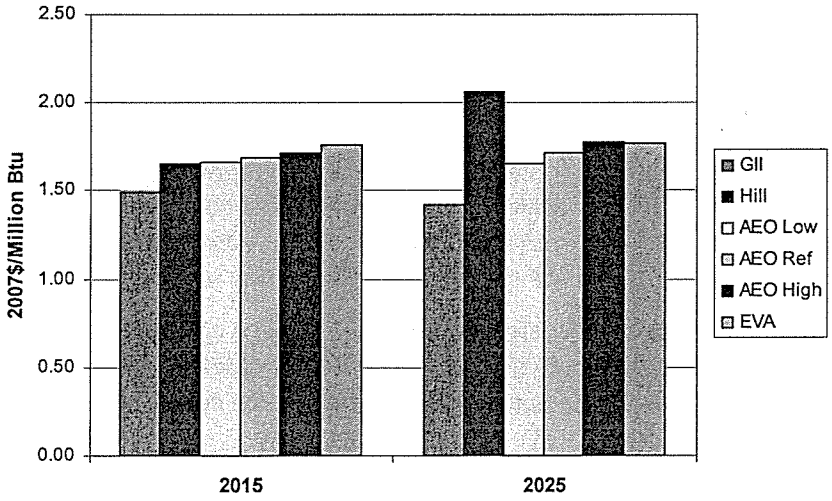


However, since 2000 coal prices have increased to levels equivalent to prices of the mid-1980s and are expected to stay at these higher levels. In 2006, coal prices stabilized and expectations are that they will remain at these levels. This was reflected in the NYMEX Central Appalachian Coal Futures through 2009. While coal at the mine mouth is relatively cheap on an energy basis, it is expensive to transport. Also, coal demand is unlikely to increase significantly because of environmental concerns. Coal is more expensive in New England because of the transportation costs and as a result provides

18% of the electric generation in New England which is a lesser fraction than most other parts of the United States. Since AEO 2007 coal prices are essentially flat and consistent with historic experience and market behavior, they were used in this analysis.

The exhibit below compares various coal price forecasts for 2015 and 2025, showing that the AEO Reference forecast is in the middle of the range.

Exhibit 4-3. Coal Price Forecasts for Electric Generation (2007$/MMBtu) [46]



[46] EIA Annual Energy Review 2007, Table 24, Comparison of Coal Projections.

iv. Biofuel Price Forecasts

Biofuel blends are a mix of a petroleum product, such as No. 2 distillate oil or diesel, and an oil-like product derived from an agricultural source (e.g., soybeans). They are relatively new to New England and are being sold as heating fuels in competition with No. 2 distillate and as transportation fuels. These products are usually labeled "B"+"NN" where NN is the percent agricultural-derived component. Thus "B20" represents a product with a 20% bio component. The biofuel product of most interest is biodiesel. It is similar to No. 2 distillate fuel oil and used primarily for heating. Currently B20 is being sold as a heating oil product by Mass Energy at about a 9% premium to conventional heating oil on a per gallon basis. However, the biofuel heat content is about 2% greater, so the net premium is about 7%. A review of the relative national prices for biodiesel B20 compared to regular diesel from the DOE Alternative Fuels Data Center[47] shows that on a heat rate basis the relative premium over the last year has varied from -1% to +3%. Since biofuels are both premium fuels (from an environmental standpoint) and sub-premium fuels (from a performance standpoint) and compete in a much larger market, an appropriate premium (positive or negative) to apply to their prices relative to the equivalent conventional fuel cannot be determined at this time. There is also the economic argument that the prices will equilibrate in the market. Thus, the prices of biofuels are forecast to be the same on an energy basis as the equivalent competitive fuel.

v. Fuel Wood Price Forecast

Prices for fuel wood can have great variability based on location, time of year, and quality (green or dry). A number of fuel wood dealers in New England were surveyed with the result being a wide range of prices. Additionally, it was very difficult to get any information from the dealers about historical prices or future price expectations.

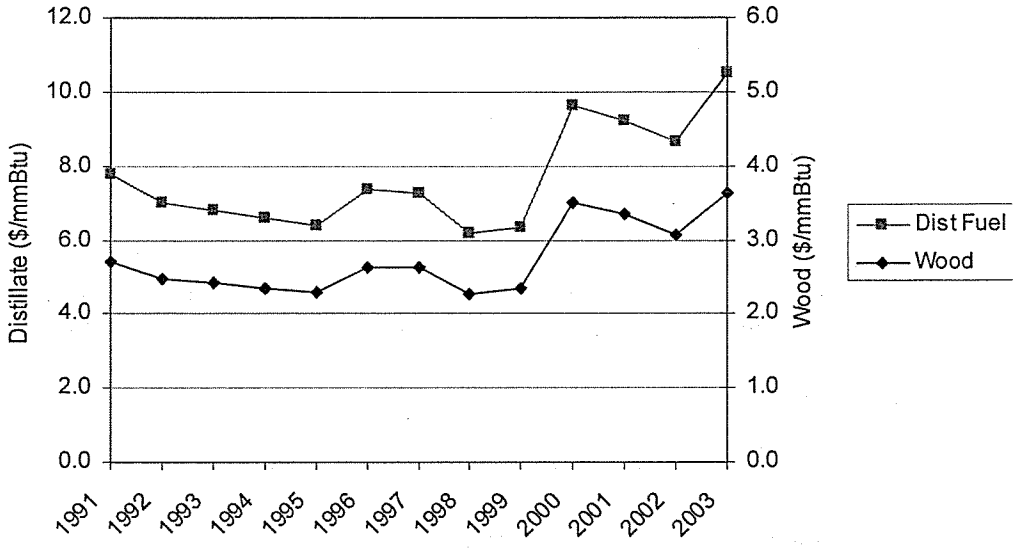
As a result, historical data was leveraged. The EIA SEDS data provides state fuel wood prices by sector. In reviewing this data, there was a very strong and consistent relationship between distillate oil and fuel wood prices.

The following graph shows the historic relationship between No. 2 Distillate and fuel wood prices in Massachusetts from 1991 through 2003.[48] The correlation between the two sets of prices is 99.4%. It is reasonable to conclude that this price relationship will continue into the future. As a result, the forecast for fuel wood prices was based on that for No. 2 Distillate.

[47] "Clean Cities Alternative Fuel Price Report" for March 2007, October 2006, and June 2006. www.eere.energy.gov/afdc/

[48] Massachusetts is the largest user of residential fuel wood in New England. The EIA data also reports the same wood prices for all the New England states.

Exhibit 4-4. Massachusetts No. 2 Distillate Fuel and Fuel Wood Prices



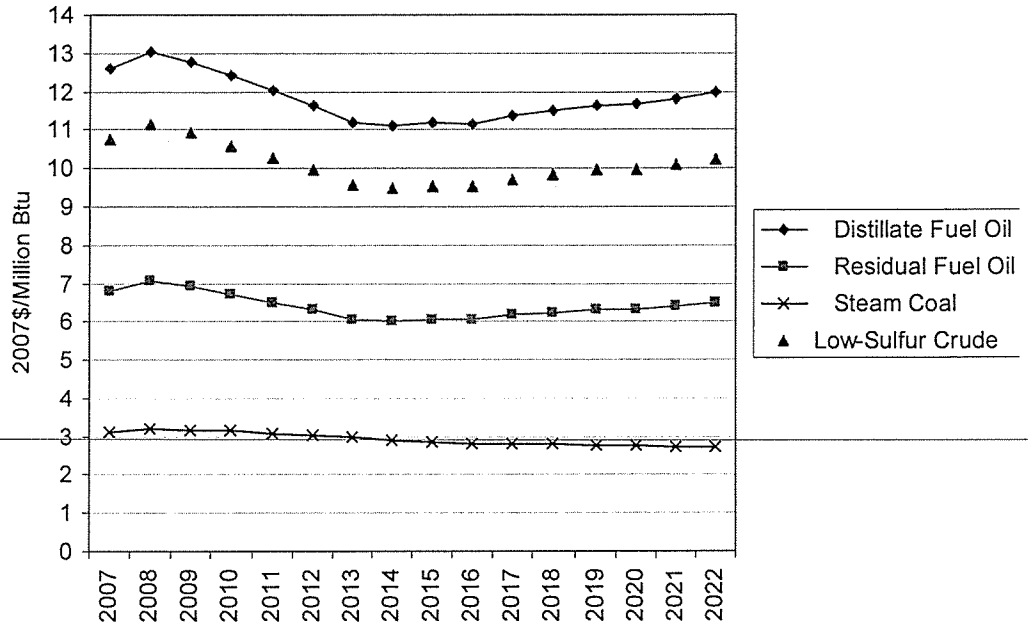
vi. Kerosene and Propane Forecasts

The kerosene and propane forecasts were derived from the underlying crude oil price forecast to maintain consistency. The relative price premiums for those products were based on the price relationships projected in the AEO 2007 forecasts for New England. For example, if the AEO forecast showed that the price of kerosene, on an energy basis, was 75% more than sweet crude oil in a given year, we applied that same 75% premium to our forecast of crude oil prices to develop our forecast price of kerosene.

B. Results

The forecasts for crude oil as compared to the forecasts of specific fuels including No. 6 residual fuel oil and No. 2 distillate fuel oil and coal are shown in the exhibit below.

Exhibit 4-5. Price Forecasts for US Crude Oil and New England Electric Generation Fuels (2007$)



The forecasted prices are close to those in AEO 2007 and they are approximately 20% higher on average than those in AESC 2005. This is primarily due to the fact that these forecasts are based upon a higher forecasted price for crude oil than assumed in AESC 2005. The forecasts by product by year are presented below in Exhibit 4-6. A table containing this forecast in nominal dollars can be found in Appendix F.

Exhibit 4-6. New England Average Price Forecast of Other Fuel Prices by Sector (2007$; Revised 08/31/07)

Fuel	No. 2 Distillate	No. 2 Distillate	No. 6 Residual Fuel <= 1% Sulfur	No. 4 Fuel Oil	Propane	Kerosene	BioFuel	BioFuel	Wood
Market	Retail	Retail	Retail	Retail	Retail	Retail			Retail
Sector	Residential	Commercial	Commercial	Commercial	Residential	Res & Com	B5 Blend	B20 Blend	Residential
Notes	1	1	2	3	4	5	6	6	7
Year	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2007	15.84	13.97	9.46	11.71	26.81	16.47	15.84	15.84	5.67
2008	16.43	14.49	9.82	12.15	28.76	17.09	16.43	16.43	5.88
2009	16.05	14.15	9.59	11.87	28.97	16.69	16.05	16.05	5.75
2010	15.58	13.74	9.31	11.52	29.43	16.20	15.58	15.58	5.58
2011	15.10	13.32	9.03	11.17	29.71	15.71	15.10	15.10	5.41
2012	14.67	12.94	8.77	10.85	30.08	15.26	14.67	14.67	5.26
2013	14.22	12.54	8.50	10.52	29.61	14.79	14.22	14.22	5.09
2014	14.03	12.37	8.38	10.38	29.63	14.60	14.03	14.03	5.03
2015	14.10	12.43	8.42	10.43	29.55	14.66	14.10	14.10	5.05
2016	14.16	12.49	8.46	10.47	29.60	14.73	14.16	14.16	5.07
2017	14.29	12.60	8.54	10.57	29.85	14.86	14.29	14.29	5.12
2018	14.42	12.72	8.62	10.67	29.76	15.00	14.42	14.42	5.17
2019	14.55	12.83	8.69	10.76	29.69	15.13	14.55	14.55	5.21
2020	14.68	12.95	8.77	10.86	29.80	15.27	14.68	14.68	5.26
2021	14.88	13.12	8.89	11.00	29.67	15.47	14.88	14.88	5.33
2022	15.07	13.29	9.01	11.15	29.82	15.68	15.07	15.07	5.40
2023	15.27	13.47	9.12	11.30	29.97	15.88	15.27	15.27	5.47
2024	15.46	13.64	9.24	11.44	30.01	16.09	15.46	15.46	5.54
2025	15.66	13.81	9.36	11.58	30.02	16.29	15.66	15.66	5.61
2026	15.79	13.92	9.44	11.68	30.05	16.42	15.79	15.79	5.66
2027	15.92	14.04	9.51	11.78	30.15	16.56	15.92	15.92	5.70
2028	16.05	14.16	9.59	11.87	30.31	16.70	16.05	16.05	5.75
2029	16.18	14.27	9.67	11.97	30.41	16.83	16.18	16.18	5.80
2030	16.31	14.39	9.75	12.07	30.45	16.97	16.31	16.31	5.84
2031	16.48	14.53	9.85	12.19	30.75	17.14	16.48	16.48	5.90
2032	16.64	14.68	9.94	12.31	31.06	17.31	16.64	16.64	5.96
2033	16.81	14.82	10.04	12.43	31.37	17.48	16.81	16.81	6.02
2034	16.98	14.97	10.14	12.56	31.68	17.66	16.98	16.98	6.08
2035	17.15	15.12	10.25	12.68	32.00	17.83	17.15	17.15	6.14
2036	17.32	15.27	10.35	12.81	32.32	18.01	17.32	17.32	6.20
2037	17.49	15.42	10.45	12.94	32.64	18.19	17.49	17.49	6.26
2038	17.67	15.58	10.56	13.07	32.97	18.38	17.67	17.67	6.33
2039	17.84	15.73	10.66	13.20	33.30	18.56	17.84	17.84	6.39
2040	18.02	15.89	10.77	13.33	33.63	18.74	18.02	18.02	6.45
Levelized									
(2008-2040)	15.61	13.77	9.33	11.55	30.29	16.24	15.61	15.61	5.59
(2009-2040)	15.58	13.74	9.31	11.52	30.36	16.20	15.58	15.58	5.58
5 years (2008-12)	15.59	13.74	9.31	11.53	29.37	16.21	15.59	15.59	5.58
10 years (2008-17)	14.91	13.15	8.91	11.03	29.50	15.51	14.91	14.91	5.34
15 years (2008-22)	14.85	13.10	8.87	10.99	29.58	15.45	14.85	14.85	5.32

Notes

1 Based on adjusted AEO 2007 forecast for New England.
2 Adjusted AEO Electrical sector forecast
3 Based on historic price difference relative to Distillate.
4 Based on adjusted AEO 2007 forecast for New England.
5 Based on historic price difference relative to Distillate.
6 No premium or discount assigned for biofuels.
7 Based on historic relationship with distillate prices.
Levelized with a real discount rate of: 2.22%

5. Electric Energy Price Forecast

This chapter provides our projection of electric energy prices and a description of the modeling methodology and assumptions.

A. Overview

The ISO New England market is part of the Northeast Power Coordinating Council (NPCC) and includes the states of Connecticut, Maine,[49] Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO New England, Inc. is the Regional Transmission Organization (RTO) for the New England power market and coordinates several markets for electric power products including energy, capacity, and operating reserves markets (Regulation Up and Down, spinning reserves, ten-minute non-spinning reserves, and thirty minute non-spinning reserves). This zonal locational marginal price-forecasting model (Market Analytics) simulates the operation of the energy and operating reserves markets, and produces forecasts of prices for each product. The model does not simulate the capacity market and, therefore, it does not require assumptions regarding the capital costs of new generation capacity, and the interconnection costs associated with such capacity. These assumptions were developed as part of the forecast of the prices for products in the capacity market and are discussed in the next section.

Market Analytics took as inputs the monthly regional fuel price forecasts reviewed in the first three sections (including the regional natural gas forecast and regional forecasts for petroleum products, coal and fuel wood). Other inputs as discussed in the Inputs section below were incorporated in order to produce an avoided electric energy cost forecast by state.

B. Zonal Locational Marginal Price-Forecasting Model

The following section provides a high-level overview of the Global Energy Decisions (GED)[50] EnerPrise Market Analytics data management and production simulation model functionality. The Market Analytics model was used to develop electricity avoided cost forecasts. Market Analytics uses the PROSYM simulation engine to produce optimized unit commitment and dispatch options. The model is a security-constrained chronological dispatch model that produces detailed and accurate results for hourly electricity prices and market operations.

The basic geographic unit in PROSYM is a sub region of a control area, called a "transmission area." Transmission areas are defined in practice by actual transmission constraints within a control area. That is, power flows from one area to another in a control area are governed by the operational characteristics of the actual transmission

[49] Parts of northeastern Maine are not included in ISO New England.

[50] Formerly Henwood Energy Services, Inc.

lines involved. New England, for example, consists of eleven transmission areas, including Southwest Connecticut as a zone. The service territories of the New England distribution utilities are mapped onto the transmission areas, and hourly load data is entered into PROSYM by distribution utility area. PROSYM can also simulate operation in any number of control areas. Groups of contiguous control areas were modeled in order to capture all regional impacts of the dynamics under scrutiny.

PROSYM uses highly detailed information on generating units. Data on specific units in the Market Analytics database are based on data drawn from various sources including the US Energy Information Administration (EIA), US Environmental Protection Agency (EPA), North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC), and ISO New England databases as well as various trade press announcements and Global Energy's own insight. Total existing capacity in the Market Analytics database was compared with the 2007 CELT report[51] and found to be reasonably consistent.

For larger units, emission rates and operating characteristics are based on unit-specific data reported to EPA and EIA rather than on data based on unit type. Operating costs for each unit are based on plant-level operating costs reported to FERC and assessment of unit type and age. For smaller units (e.g., combustion turbines), most input data are based on unit type. All generating units in PROSYM operate at different heat rates (efficiencies) at different loading levels. This distinction is especially important in the case of combined-cycle units, which often operate in a simple-cycle mode at low loadings. PROSYM determines the fuel a unit burns by placing each generating unit into a "fuel group." PROSYM does not limit the number of fuel groups used, and creating new fuel groups to simulate a few unusual units is a simple matter. In New England, for example, it is especially important to model the operation of dual-fueled units as accurately as possible.

Based upon hourly loads, PROSYM will determine generating unit commitment and operation by transmission zone based upon economic bid-based dispatch, subject to system operating procedures and constraints. PROSYM operates using hourly load data and simulates unit dispatch in chronological order. In other words, 8,760 distinct load levels are entered for each transmission area for each study year. The model begins on January 1st and dispatches generating units to meet load in each hour of the year. Using this chronological approach, PROSYM takes into account time-sensitive dynamics such as transmission constraints and operating characteristics of specific generating units. For example, one power plant might not be available at a given time due to its minimum down time (i.e., the period it must remain off line once it is taken off). Another unit might not be available to a given transmission area because of transmission constraints created by current operating conditions. These are dynamics that system operators wrestle with daily, and they often cause generating units to be dispatched out of merit order. Few other electric system models simulate dispatch in this kind of detail.

[51] CELT is ISO-NE's annual 10-year forecast of capacity, energy, loads and transmission.

The model's fundamental assumption of behavior in competitive energy markets is that generators will bid their marginal cost of producing electric energy into the energy market. The model calculates this marginal cost from the unit's opportunity cost of fuel[52] or the spot price of gas at the location closest to the plant, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions.

PROSYM does not make capacity expansion decisions internally. Instead, the user specifies capacity additions, which increases transparency and allows the system expansion plans to be specified to reflect non-market considerations. PROSYM also models randomly occurring forced outages of generating units probabilistically rather than as deterministic capacity de-rating, thereby producing more accurate estimates of avoided costs, particular for peak load periods. PROSYM models generating units with a much higher level of detail including inputs for unit specific ramp rates, minimum up/down times, and multiple capacity blocks, all of which are critical for accurately modeling hourly prices. This modeling capability enabled production of locational prices by costing period in a consistent manner at the desired level of detail.

PROSYM simulates the effects of forced (i.e., random) outages probabilistically, using one of several Monte Carlo simulation modes. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo-type random number draw. Many other models simulate the effect of forced outages by "de-rating" the capacity of all generators within the system. That is, the capacities of all units are reduced at all times to simulate the outage of several units at any given time. While de-rating usually results in a reasonable estimate of the amount of annual generation from baseload plants, the result for intermediate and peaking units can be inaccurate, especially over short periods.

PROSYM calculates emissions of NO_x, SO_2, CO_2, and mercury based on unit-specific emission rates. Emissions of other pollutants (e.g., particulates and air toxics) are calculated from emissions factors applied to fuel groups.

C. Input Assumptions Used to Develop the Electric Energy Price Forecast

The avoided electric energy costs were strongly dependent on the quality of the input assumptions that were integrated into Global Energy's zonal price forecasting model. The input assumptions include: topology, thermal unit characteristics, conventional hydro and pumped storage unit characteristics, renewable unit characteristics, hourly load profiles, forecasted annual peak demand and total energy, transmission system paths and upgrades, Reliability-Must-Run (RMR) Contracts, reserve margin multiplier, additions,

[52] A number of generators have the ability to utilize a secondary fuel type. Units that are allowed to burn gas or fuel oil are allowed to burn oil during the winter months (December, January, and February) and burn natural gas during the rest of the year. Fuel switching only occurs if oil is the less expensive option for these plants.

retirements, uprates, outages, environmental regulations, demand response resources, marginal cost bidding, installed capacity, and ancillary services.

i. Electric Market Zone Topology

Market Analytics represents load and generation zones at various levels of aggregation. Assets within the Market Analytics model, including physical or contractual resources such as generators, transmission links, loads and transactions, are mapped to physical locations which are then mapped to Transmission Areas. Multiple Transmission Areas are linked by transmission paths to create Control Areas. For this study, New England is represented by 11 Transmission Areas that are based on the 13 load zones as defined by ISO New England for the 2006 Regional System Plan.[53] Neighboring regions that are modeled in this study are New York, Quebec, and the Maritime Provinces.[54] Areas outside of New England are represented with a high level of zonal aggregation to minimize model run time. The load and generation zones as they were modeled is presented in Exhibit 5-1.

[53] Market Analytics combines western and central Maine/Saco Valley, New Hampshire and southeastern Maine to form ME-CMP and includes Norwalk/Stamford in CT-SW.

[54] The Maritimes zone includes Maine Public Service (MPS) and Eastern Maine Electric Cooperative (EMEC) which are not part of ISO New England and, therefore, are not included in any of the New England pricing zones used in this study. MPS and EMEC are not modeled as part of the Maine pricing zone and were modeled as part of the New Brunswick transmission area. However, the forecast energy prices for the New Brunswick transmission area were on average within about 1% of the prices for the modeling zones included in the Maine pricing zone and MPS and EMEC constitute a small portion of Maine's total load (approximately 6-7%). Market prices for standard-offer supply have been similar (considering the timing of procurement) among the three Maine utilities. Therefore, it is appropriate to apply the avoided costs for the Maine pricing zone to the entire state of Maine.

Exhibit 5-1. Zones Used to Model New England Electric Market Prices

Region	Zone Designation	Description
New England	BHE	Northeastern Maine
	ME-CMP	Southeastern Maine and western and central Maine/Saco Valley, New Hampshire
	NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine
	VT	Vermont/southwestern New Hampshire
	Boston	Greater Boston, including the North Shore
	CMA/NEMA	Central Massachusetts/northeastern Massachusetts
	WMA	Western Massachusetts
	SEMA	Southeastern Massachusetts/Newport, Rhode Island
	RI	Rhode Island/bordering MA
	CT	Northern and eastern Connecticut
	CT-SW	Southwestern Connecticut including Norwalk/Stamford
New York	NY	NY-ISO control area
Quebec	HQ	Hydro Quebec control area
Maritimes	M	Maritimes control area

The model explicitly models neighboring control areas that have direct connections to the New England grid, including New York ISO, the Maritimes region (New Brunswick, Nova Scotia, and Prince Edwards Island), and Hydro Quebec. These external markets are modeled in the same manner and simultaneously with New England. The Global Energy database is used as the primary data source for external regions. New capacity is added to meet RPS requirements and generic gas capacity is added based on the same methodology that is used in New England.

ii. Existing Generating Unit Characteristics

(a) Thermal Unit Characteristics

Market Analytics models generation units in detail, in order to accurately simulate their operational characteristics and therefore project realistic hourly dispatch and prices. These characteristics include:

- Unit type (steam-cycle, combined-cycle, simple-cycle, cogeneration, etc)
- Heat rate values and curve
- Seasonal capacity ratings (maximum and minimum)
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs
- Ramp rates
- Emission rates (SO_2, NO_x, CO_2, and mercury)

Exhibit C-2 in Appendix C summarizes the thermal unit characteristic assumptions used in our modeling.

(b) Nuclear Unit Characteristics

There are four nuclear plants in New England (Millstone, Pilgrim, Seabrook, and Vermont Yankee) with a combined capacity of 4,775 MW which is approximately 15% of the total capacity in New England. It is, therefore, important to assess whether or not all of the units at these plants will continue to operate during the study period. The exhibit below shows the capacity of each nuclear unit and its license expiration date.

Exhibit 5-2. New England Nuclear Unit Capacity and License Expirations

Unit	AESC Zone	Capacity MW[55]	License Expiration Year[56]
Millstone 2	CT	940	2035
Millstone 3	CT	1253	2045
Pilgrim	SEMA	670	2012
Seabrook	NH	1242	2017
Vermont Yankee	VT	670	2012

[55] Nuclear capacity values are the nameplate capacity values for these units in the Market Analytics database.

[56] Source – U.S. Nuclear Regulatory Commission: www.nrc.gov.

License renewals for the Pilgrim and Vermont Yankee plants are currently being reviewed by the Nuclear Regulatory Commission (NRC) and Seabrook will be coming up for renewal during the study period. In the past seven years, the NRC has reviewed license extensions for 27 plants and not one of these applications was denied.[57] Based on this track record and the lack of evidence that suggests that license renewal applications for any of these plants will be denied, it was assumed that all of the nuclear plants in New England will continue to operate for the entire study period.

The owners of Millstone have filed an application for a 70 MW uprate on Unit 3 for operation by the end of 2008.[58] Based on the fact that the NRC has never denied an uprate application,[59] it was assumed that this uprate will be approved and the uprated capacity will be in operation starting in 2009.

The maintenance schedules included in the Market Analytics database are based on information from the NRC website and the trade press for refueling outages as well as ISO New England and the Nuclear Energy Institute. Future outages are estimated by using typical refueling cycle, outage length, and last known outage dates of each plant to project refueling outages.

(c) Conventional Hydro and Pumped Storage Unit Characteristics

The Global Energy database was used as the primary source all hydro unit information. Conventional reservoir and run-of-river hydro resources are considered a "fixed energy" station or contract in the model. Like thermal stations, these stations have a maximum and minimum generating capacity, but they also have a fixed amount of energy available within a specified time (i.e., a week or a month). Hydro stations operate generally on peak in a manner that levels the load shape served by other stations. Hydro stations are scheduled one at a time over the horizon of a week, subject to hourly constraints for minimum and maximum generation, and weekly constraints for ramp rates and total energy. Although the load shape they intend to level is the overall system load, a hydro station can be scheduled against the load of a specified transmission area or control area.

Pumped-storage type resources (exchange contracts) have slightly different modeling requirements, typically involving a series of reservoirs used to release water for energy generation during peak load periods and pump water back uphill during off-peak times when energy demand and price is lower. The water (fuel) of pumped hydro generation is valued at the cost of pumping, allowing for net plant efficiency. Hourly reservoir levels are computed and a look-ahead is employed to prevent drawing the reservoir below the level where pumping space allows refilling to the desired level before the beginning of the next peak period.

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[57] Source – Nuclear Energy Institute: http://www.nei.org/documents/U.S._Nuclear_License_Renewal_Filings.pdf

[58] Source – ISO New England Generator Interconnection Queue

[59] Source – U.S. Nuclear Regulatory Commission: www.nrc.gov.

(d) Renewable Unit Characteristics

The Global Energy database includes several existing renewable generators in New England. These include wind, biomass, landfill gas, and municipal solid waste-to-energy facilities. All of these units were modeled as thermal units with seasonal forced outage rates that reflect historic seasonal capacity factor profiles.

iii. Load Forecast

Historical profiles for each utility were developed by Global Energy Decisions based on a set of annual historic load shapes. Hourly load profiles based on historical profiles were calculated for each load serving entity. Loads were then mapped to transmission areas based on location ratios.

Hourly load data for future years were scaled based on forecasted annual peak demand and total energy. Forecasted annual peak demand and total energy were derived from the 2007 CELT report and the 2006 Regional System Plan (RSP), published by ISO New England. The 2007 CELT report was released on April 18, 2007. However, the detailed load forecast data for the ISO's RSP zones (which the Market Analytics zones are based on) was not released in time to be included in the modeling. Instead, the ISO released the load forecasts for each New England state that it had used to develop the forecast presented in the 2007 CELT.[60] As a result, the load forecasts for each zone in the Market Analytics model were derived from the ISO-NE 2007 CELT state-level load forecasts for 2007-2016 as summarized in Exhibits 5-3 and 5-4. For 2017-2022, load in each zone is assumed to grow at the Compound Annual Growth Rate (CAGR) of the 2007-2016 period.[61]

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[60] Available on the ISO New England website: http://www.isonewengland.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/apr52007/revised_%20pac18_preliminary_rsp_load_forecast.xls.

[61] In July we were advised that the forecast of peak demand and energy we used to develop our forecast of energy prices was not entirely consistent with the trends currently projected by the ISO for the last five years of the study, 2017 through 2022. The system load factor from 2017 through 2022 under the current ISO New England forecast is somewhat higher than that under the forecast we used, reflecting their assumption that air conditioning penetration will approach a saturation point after 2016. Our review indicates that our projection of energy prices is still reasonable despite the slight differences in system load factor from 2017 to 2022. Had we used a forecast with a system load factor consistent with that currently projected by the ISO, our projected energy prices in peak periods would have been somewhat lower, all else being equal. However, under such a load forecast the projected mix of capacity additions would likely have also been different, with less new, efficient CT and CC capacity added. That change in capacity mix would have resulted in higher projected energy prices. Thus, our review indicates that using a forecast with a somewhat higher system load factor from 2017 to 2022 would not result in materially different energy prices.

Exhibit 5-3. Summer Peak Forecast by State (MW)

State	2007	2016	2007-2016 CAGR	2022
CT	7,317	8,475	1.6%	9,322
MA	12,623	14,595	1.6%	16,053
ME	2,033	2,400	1.9%	2,671
NH	2,444	3,000	2.3%	3,439
RI	1,877	2,185	1.7%	2,418
VT	1,067	1,230	1.6%	1,353
ISO-NE	27,360	31,885	1.7%	35,255

Note: 2017-2022 values were developed by growing 2016 values by 2007-2016 CAGR

Exhibit 5-4. Energy Forecast by State (GWh)

State	2007	2016	2007-2016 CAGR	2022
CT	33,929	38,060	1.3%	41,127
MA	60,155	65,670	1.0%	69,710
ME	11,820	13,390	1.4%	14,555
NH	11,895	13,775	1.6%	15,151
RI	8,463	9,270	1.0%	9,840
VT	6,354	7,020	1.1%	7,496
ISO-NE	132,616	147,190	1.2%	158,111

Note: 2017-2022 values were developed by growing 2016 values by 2007-2016 CAGR

Load allocation factors from the ISO New England 2006 Regional System Plan, shown in Exhibit C-1 in Appendix C, were applied to the state-level load forecasts from the 2007 CELT Report to develop the load forecasts for each transmission area. The load allocation factors represent the portion of each state's load that is mapped to each RSP sub-area.[62] The load forecasts for each zone in the Market Analytics model are summarized in the exhibits below.

[62] Table 3-6 in the ISO New England 2006 RSP.

Exhibit 5-5. Market Analytics Modeled Summer Peak Forecast by Zone (MW)

Zone	2007	2016	2007-2016 CAGR	2022
BHE	313	370	1.9%	411
BOSTON	5,501	6,366	1.6%	7,007
CMA/NEMA	1,763	2,044	1.7%	2,253
CMP	1,730	2,045	1.9%	2,278
CT	3,612	4,184	1.6%	4,602
NH	1,963	2,404	2.3%	2,752
RI	2,489	2,891	1.7%	3,193
SEMA	2,976	3,442	1.6%	3,787
SWCT	3,632	4,207	1.6%	4,628
VT	1,246	1,460	1.8%	1,625
WMA	2,087	2,413	1.6%	2,654

Note: 2017-2022 values were developed by growing 2016 values by 2007-2016 CAGR

Exhibit 5-6. Market Analytics Modeled Energy Forecast by Zone (GWh)

Zone	2007	2016	2007-2016 CAGR	2022
BHE	1,820	2,062	1.4%	2,241
BOSTON	26,224	28,655	1.0%	30,436
CMA/NEMA	8,409	9,207	1.0%	9,791
CMP	9,999	11,335	1.4%	12,325
CT	16,749	18,789	1.3%	20,303
NH	9,631	11,130	1.6%	12,227
RI	11,418	12,494	1.0%	13,262
SEMA	14,142	15,441	1.0%	16,391
SWCT	16,843	18,894	1.3%	20,416
VT	7,063	7,888	1.2%	8,482
WMA	10,024	10,959	1.0%	11,644

Note: 2017-2022 values were developed by growing 2016 values by 2007-2016 CAGR

ISO New England changed its long-run load forecasting methodology this year to reflect the fact that DSM resources may participate in the Forward Capacity Market.[63] Under this new methodology, the ISO-NE load forecast reflects the future, ongoing impact of DSM programs implemented up to 2006.[64]

The load forecast we used in our simulation of the New England market deliberately does not reflect the potential impact of new DSM programs that would be implemented in 2007 and beyond. The exclusion of those potential impacts is consistent with the purpose of our study which is to forecast electric energy prices that would occur in the absence of new DSM programs.

[63] Conversation with Dave Erlich, April 9, 2007.

[64] In previous years, ISO New England developed a long-run load forecast excluding any future DSM savings from any programs, past or future in its "Unadjusted Load" forecast, and then subtracted forecast DSM savings to develop its "Adjusted Load" forecast.

iv. Transmission System Paths and Upgrades

Transmission path assumptions were developed by Global Energy based on the zonal transmission paths represented in the ISO-NE 2006 Regional System Plan. The transmission system within Market Analytics is represented by links between Transmission Areas. These links represent aggregated actual physical transmission paths between locations. Each link is specified by the following variables:

- "From" location
- "To" location
- Transmission capability in each direction
- Line losses in each direction
- Wheeling charges

The exhibit below shows the transmission capabilities of each path between New England zones and between New England and external areas as indicated in the Global Energy database. These capabilities are consistent with the interface limits that are used in the ISO New England 2006 RSP.

Exhibit 5-7. New England Zonal Transmission Interface Limits

Path Type	Name	"From" Zone	"To" Zone	Capacity "From-To" (MW)	Notes	Capacity Back (MW)	Notes
Transmission Paths within New England	BHE-CMP	BHE	CMP	1200		1050	
	CMA-BOSTON	CMA/NEMA	BOSTON	2800	As of 1/1/2006	3000	
				3000	As of 1/1/2008		
	CMA-NH	CMA/NEMA	NH	912		925	
	CMA-WMA	CMA/NEMA	WMA	960		2000	
	CT-RI	CT	RI	720		720	
	CTSW-CT	CTSW	CT	2000		2575	As of 1/1/2007
						3400	As of 1/1/2010
	NH-BOSTON	NH	BOSTON	900		912	
	NH-MAINE	NH	CMP	1400		1500	
	NH-VERMONT	NH	VT	720		715	
	RI-BOSTON	RI	BOSTON	400		400	
	RI-CMA	RI	CMA/NEMA	1480		600	
	RI-SEMA	RI	SEMA	1000		3000	
	SEMA-BOSTON	SEMA	BOSTON	400		400	
	VERMONT-WMA	VT	WMA	875		875	
	WEMA-CT	WMA	CT	680		710	
Transmission Paths between New England and External Control Areas	BHE-NBPC	BHE	Maritimes	600	As of 10/1/2007	1000	As of 10/1/2007
	HYQB-VT (Highgate)	HQ	VT	225	Peak month capacity	170	Peak month capacity
	CTSW-NYZK	CTSW	NY	100		100	
	MPS-BHE	Maritimes	BHE	127		127	
	NYZD-VERMONT	NY	VT	150		150	
	NYZF-WEMA	NY	WMA	275	Peak month capacity	650	
	NYZG-CT	NY	CT	700		500	
	NYZK-CT (CSC)	NY	CT	300		330	
	CMA-HYQB (Phase II)	CMA/NEMA	HQ	1300	Peak month capacity	1921	Peak month capacity

The interface limits presented in the exhibit above include the following transmission upgrades from the 2006 RSP:[65]

- **Northeast Reliability Interconnect Project** – this comprises a new 345 kV line from New Brunswick to the Orrington Substation in northern Maine and increases the transfer capability from New Brunswick to Maine by 300 MW. This project is scheduled to be online by the end of 2007.
- **NSTAR 345 kV Transmission Reliability Project** – this project involves construction of a Stoughton 345 kV station and three new underground 345 kV lines, two of which are already completed and the third is scheduled for completion by the end of 2007. This project increases the Boston import capability by approximately 1,000 MW.
- **SWCT Reliability Project** – this project includes two phases of new 345 kV circuits. The combined effect of these two phases is to increase the import capability into Southwest Connecticut by approximately 1,100 MW by the end of 2009.

Transmission system upgrades beyond what was included in the Global Energy database were considered; however, no additional upgrades needed to be included.

v. Reliability-Must-Run (RMR) Contracts

Unlike the 2005 AESC study, the current study does not consider any costs related to existing reliability contracts (sometimes called "reliability must-run" or RMR contracts) as being avoidable. Exhibit 5-8 lists the plants with reliability agreements that last beyond 2007.[66] These remaining reliability contracts are scheduled to expire in June 2010 when the FCM commences operation. Load reductions are unlikely to result in these contracts being avoided prior to 2010. Prior to 2010 we assume that these units will be needed. Based on that assumption, if the revenues these units receive from their market sales were to decline due to load reductions to the point that they were not covering their costs, we expect that ISO-NE would simply initiate new agreements and collect the revenue shortfall from New England customers.

[65] The Northwest Vermont Reliability Project is not included in this list because it does not affect the import capability into Vermont.

[66] "Reliability Agreements – Annual Fixed Costs Summary," ISO-NE, April 19, 2007.

Exhibit 5-8. List of Plants with Reliability-Must-Run Contracts through 2007

Owner/Unit	Plant Type	2007 CELT Summer Cap MW	Annualized Fixed Revenue Requirement $M	$/kW-year total	$/kW-year Net of FCM
West Central Mass					
ConEd -- W.Springfield 3	ST	94	$7	$75	-
Berkshire Power	CC	229	$26	$113	$13
Pittsfield Gen.--Altresco"	CC	141	$13	$92	-
ConEd -- W.Springfield GT-1&2	CT	74	$12	$161	$61
Sub-Total WCMA		**539**	$58 M		$8 M
Connecticut					
NRG -- Middletown 2-4, 10	ST, CT	770	$50	$64	-
NRG -- Montville 5,6,10&11	ST, CT	494	$29	$58	-
Milford 1 and 2	CC	492	$82	$166	$66
PSEG -- New Haven Harbor	ST	448	$47	$106	$6
PSEG -- Bridgeport Harbor 2	ST	130	$19	$146	$46
Bridgeport Energy	CC	448	$58	$129	$29
Sub-Total Connecticut		**2,782**	$284 M		$54 M

vi. New Generation Additions

In order to meet future load growth, new generation resources were added to the existing generation mix. Market Analytics is not a capacity expansion model that optimizes capacity additions by choosing among a set of resource alternatives to develop a least cost expansion plan. Therefore, three types of additions were used to manually add new resources to meet reserve needs:

- Planned Additions & Uprates – Near-term proposed new additions and uprates to existing plants that were in development or advanced stages of permitting and had a high likelihood of reaching commercial operation;
- RPS Additions – Renewable generators that were added to meet existing or anticipated renewable portfolio standards (RPS) in each state; and,
- Generic Additions – New generic conventional resources that were added to meet the residual capacity need after adding planned and RPS additions.

(a) Planned Additions & Uprates

The AESC 2007 forecast was based on projects in development or advanced stages of permitting, as indicated by the 2007 CELT Report, review of the current ISO New

England interconnection request queue,[67] trade press, environmental permit applications to the state departments of environmental protection, and internal knowledge. New entry assumptions are shown in the exhibit below. These planned additions represent the additions that ISO New England has indicated are highly likely to reach commercial operation.[68]

Exhibit 5-9. Planned Additions & Uprates

Project	State	AESC Zone	Type	Fuel	Projected On-line Date	Capacity (MW)
Kleen Energy Project	CT	CT	CC	NG/DFO	1/1/2020	620
Peabody Power	MA	BOSTON	CT	NG/DFO	5/1/2008	97
Lowell Power Generators	MA	CMA/NEMA	CT	NG	1/1/2008	99
Gas Turbine	CT	SWCT	CT	NG/DFO	9/1/2007	90
Hoosac Wind Project	MA	WMA	WT	Wind	12/31/2007	30
Fitchburg Renewable Energy	MA	CMA/NEMA	IC	LFG	6/30/2007	7
Millstone 3	CT	CT	NUC	NUC	1/1/09	70

(b) RPS Additions

New renewable generation resources will be added to each state to meet existing or expected renewable portfolio standards (RPS). Each state in New England has different RPS targets and different requirements for meeting these targets. The major requirements by state are detailed in Exhibit C-3 in Appendix C.

The resources that are eligible to meet these targets vary by state; however, it was assumed that RPS requirements will be met by a mix of renewable resource generation consistent with the mix of resources in the ISO-NE queue (type and quantity). As a result, additions included only wind, solar, landfill gas, and biomass generators. The assumed resource mix was 65% wind, 33% biomass, 1% LFG, and 1% solar.[69] It was assumed that these proportions would remain constant throughout the study period with the following

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[67] The ISO New England interconnection request queue is a list of proposed new generation resources that have submitted an Interconnection Request form to the ISO and are in various stages of the development process.

[68] From a presentation by Peter Wong to the ISO New England Planning Advisory Committee on February 27, 2007: http://www.isonewengland.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/feb272007/new_resources_in_the_ISO_queue.pdf.

[69] These quantities are based on the mix of renewable resources in the ISO New England interconnection queue with the additional assumption that 1% of requirements will come from solar PV. The proportion of solar PV resources will initially be less than 1% and will gradually increase over time to account for the expected cost reductions and technology improvements in future years.

exception: the proportion of solar photovoltaic (PV) resources would initially be less than 1% and would gradually increase over time to account for the expected cost reductions and technology improvements in future years. It was assumed that new RPS resources would be located based on locations of projects currently in the ISO-NE queue. The exception will be solar PV, which was distributed in each transmission area proportionately to load.

The operating characteristics of these resources are shown in the exhibit below. These assumptions will be based on the technology assumptions used by ISO New England in its current scenario planning process as well as other sources.

Exhibit 5-10. Operating Costs and Characteristics for New RPS Additions

Technology Type	Biomass	Landfill Gas	Wind On-shore	Wind Off-shore	Solar PV	Source
Typical Generator Size (MW)	40	5	1.5	3.5	1	1
Heat rate	14000	10500	n/a	n/a	n/a	1
Fixed O&M costs (2007$/kW-yr)	51.70	111.83	35.34	50.31	72.46	2,3,4
Variable O&M costs (2007$/MWh)	0.42	0.00	0.00	0.00	0.00	2,4
Availability	60%	90%	90%	90%	98%	1
NOx (lb/Mbtu)	0.075	0.03	0	0	0	1
SO2 (lb/Mbtu)	0.02	0.2	0	0	0	1
CO_2 (lb/Mbtu)	170	0	0	0	0	1
Average Capacity Factor	n/a	n/a	35%	39%	16%	5
Peak Capacity Credit	100%	100%	19%	26%	40%	5

Sources:
1. ISO-NE 2007. "Resource Assumptions" presentation for the ISO-NE Scenario Analysis Working Group, 4/2/2007
2. AESC 2005, Exhibit 2-25, 2-26 for CC, CT, Biomass, Landfill gas, on-shore wind
3. PV Fixed O&M: "Energy Cost Savings Module", Prepared for the Massachusetts DG Collaborative, Navigant Consulting, January 20, 2006.
4. Off-shore wind: "New Jersey Renewable Energy Market Assessment", Navigant Consulting, August, 2004.
5. ISO-NE 2007. "Wind and Photovoltaic Assumptions" presentation for the ISO-NE Scenario Analysis Working Group, 4/2/2007

RPS additions were made to the New England system based on the annual sum of renewable requirements for each state RPS. Resources were dispersed geographically as follows:

- Wind – based on currently proposed wind farm development patterns throughout New England
- Biomass – distributed proportionately to load
- Landfill Gas (LFG) – distributed proportionately to load
- Solar – distributed proportionately to load

The operating characteristics of these resources were based on the technology assumptions used by ISO New England in its current scenario planning process as well as our review of assumptions from various other sources.

(c) Generic Additions

In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions were added to the model. A range of generation technologies was initially considered for this purpose, including gas/oil-fired combined-cycle, gas/oil combustion turbines, conventional coal, integrated gasification combined cycle (IGCC), and nuclear. However, the development queue did not indicate that any coal or nuclear resources would be developed in New England during the forecast period. Although the region is already heavily reliant on gas-fired generation and the ISO has stated a goal of increasing the fuel diversity of the region,[70] the costs and risks of investing in new coal or nuclear generators are very high. Additionally, coal and nuclear resources are generally baseload units that do not have a significant impact on marginal costs since they are rarely on the margin. Therefore, generic additions were comprised entirely of gas/oil fired 300 MW combined-cycle and 100 MW combustion turbines. The assumed mix of combined cycle and combustion units was 45%/55%. This was based on the ratio of these types of resources in the ISO New England interconnection queue as of March 30, 2007. No coal or nuclear units were added.

Generic additions were added until a system-wide reserve target of 14.3%[71] was met. New resources were dispersed geographically based on a combination of zonal need and historic zonal capacity surplus/deficit patterns. It was anticipated that the Forward Capacity Market would provide incentive to build new generation in the constrained zones of Southwest Connecticut (SWCT) and Boston. However, siting new plants in these zones will likely be difficult. Therefore, it was also anticipated that some new capacity will be added outside of these zones.

Distributed generation technologies (DG) were considered, but not included, as generic additions. The decision to not include DG was based on a review of several studies of the technical and economic potential of DG in New England.[72,73,74] Although these studies suggested that DG capacity in Connecticut and Massachusetts could reach levels of a few hundred megawatts by the end of the study period, the uncertainty regarding the economics of these resources made it difficult to predict what level of DG resources will be installed. Also, the likely penetration level for DG resources is not likely to have a significant impact on the overall avoided energy costs.

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[70] ISO New England 2006 Regional System Plan.

[71] Target based on ISO New England recommended Installed Capacity Requirements for the 2007 - 2008 Power Year as presented to the Power Supply Planning Committee on March 15, 2007.

[72] Beka Kosanovic, PhD. "How Attractive is DE for Massachusetts Energy Users and Society" presented at the MTC DG Symposium on January 18, 2007.

[73] Andy Brydges with KEMA, "Projections of DG in Massachusetts" presented at the MTC DG Symposium on January 18, 2007.

[74] Institute for Sustainable Energy at Eastern Connecticut State University 2004. "Distributed Generation Market Potential: 2004 Update / Connecticut and Southwest Connecticut," available at: http://www.easternct.edu/depts/sustainenergy/publication/Press%20Releases/March%2023,%202004%20-%20DG%20Update.htm

vii. Retirements

Global Energy includes assumptions regarding retirement of existing resources. The Global Energy database uses lifetime assumptions for certain technology types to determine retirements. However, it was determined that no units should be assumed to retire given that many units will likely continue to operate for reliability and/or economic reasons.

viii. Environmental Regulations

Market Analytics has the ability to model multiple effluents and apply costs to these emissions. This model included price forecasts for SO_2, NO_x, CO_2, and mercury. The model included the costs associated with each of these emissions when calculating bid prices and making commitment and dispatch decisions. Allowance price forecasts associated with the Ozone Transport Commission (OTC) NO_x Budget Program and the Acid Rain Program were included in unit operating costs for this study. Allowance price forecasts were also included to represent future cap and trade emission reduction programs for mercury and CO_2.[75]

(a) SO_2 and NO_x

There has been a significant reduction in SO_2 and NO_X emission allowance costs over the last several years. For example, consider the SO_2 allowances for 2009: in mid 2005 they were selling for $670/ton, in March 2006 they were relatively unchanged at $700/ton, by September 2006 they were down to $570/ton, and by March 2007 they were down to $430/ton. Similar reductions occurred in the NO_x allowance markets. These reductions are influenced by a number of factors including the decline in natural gas prices, but a significant component is that the control costs, especially for NO_x, are proving to be less than previously thought.

The establishment of new limits on mercury emissions is leading to the installation of additional scrubbers which also reduce SO_2 emissions. Yet looking to 2010 and beyond, new limits on air emissions associated with the Clean Air Interstate Rule (CAIR) are likely to require new controls and push up allowance costs. This is reflected in the forecast of future allowance costs in the EIA's AEO 2007. However, considering the significant price reductions shown in the allowance markets for years both before and after 2010, the AEO forecast that was constructed in the fall of 2006 now seems too high. Thus we have adjusted the AEO price forecasts for after 2010 to reflect the relative changes in the markets between September 2006 and March 2007.

SO_2 allowance prices represent a hybrid between recently reported trading prices for SO_2 allowance futures[76] and the AEO 2007 SO_2 allowance price forecast with the adjustments described above to account for the recent drop in allowance prices. The futures prices were used for the years 2007 through 2010. The allowance prices for the years 2011 to

[75] Emissions caps were not modeled explicitly, instead allowance prices are assumed to represent the appropriate levels to attain any emission caps set by emission control programs.

[76] As reported in *Argus Air Daily*, March 30, 2007.

2014 represent an interpolation between the 2010 futures price and the 2015 AEO 2007 forecast price. The AEO 2007 price forecast was used for the years 2015 to 2022.

NO_x allowance prices represent a hybrid between recently reported trading prices for NO_x allowance futures[77] and the AEO 2007 NO_x allowance price forecast with the adjustments described above to account for the recent drop in allowance prices. The futures prices were used for the years 2007 through 2009. The allowance prices for the years 2010 and 2011 represent an interpolation between the 2009 futures price and the 2012 AEO 2007 forecast price. The AEO 2007 price forecast was used for the years 2012 to 2022.

(b) Mercury

The Clean Air Mercury Rule (CAMR) established a mercury emission allowance cap and trade program that will begin in 2010. For the allowance price forecast for mercury, we used the price forecast that was developed by Global Energy Decisions for their Fall 2006 Reference Case Forecast.

(c) CO_2

The CO_2 allowance price forecast is based upon the Regional Gas Greenhouse Initiative (RGGI) in the short-run and expected federal greenhouse gas regulations in the long-run. Allowance prices for each ton of CO_2 emitted are based on expected RGGI prices starting in 2009 and continuing until 2012[78] by which point it is expected that a national cap and trade program will be implemented for greenhouse gases.[79]

The allowance price forecast for each effluent is shown in the exhibit below.

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[77] As reported in *Argus Air Daily*, March 30, 2007.

[78] The RGGI forecast is from the IPM modeling results for the "RGGI Package Scenario (Updated October 11, 2006)" which can be found on the RGGI website at the following link: http://www.rggi.org/docs/packagescenario_10_11_06.xls.

[79] The forecast for the federal program is based on a review of several proposed federal bills aimed at reducing greenhouse gas emissions by Synapse Energy Economics. The Synapse CO_2 forecast methodology is documented in Synapse's June 8, 2006 report, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," which can be found at http://www.synapse-energy.com.

Exhibit 5-11. Allowance Prices for SO_2, NO_x, Mercury (Hg) and CO_2 (2007$)

Year	SO2 $/ton	NOx $/ton	Mercury $million/ton	CO_2 $/ton
2007	$434	$1,013	$0.00	$0.00
2008	$433	$925	$0.00	$0.00
2009	$432	$800	$0.00	$2.21
2010	$470	$1,171	$12.66	$2.37
2011	$526	$1,715	$12.66	$2.53
2012	$563	$1,750	$12.66	$9.46
2013	$590	$1,750	$12.66	$11.56
2014	$610	$1,750	$12.66	$13.66
2015	$750	$1,750	$12.66	$15.76
2016	$750	$1,750	$12.66	$17.86
2017	$750	$1,750	$12.66	$19.96
2018	$750	$1,750	$12.66	$22.06
2019	$750	$1,750	$12.66	$24.16
2020	$750	$1,750	$12.66	$26.27
2021	$750	$1,750	$12.66	$27.32
2022	$750	$1,750	$12.66	$28.37

(d) Demand Response Resources

Demand response (DR) resources that were directly modeled in this analysis include resources that were participating in the "RT 30-Minute" and "RT 2-Hour" ISO New England Demand Response programs as of March 30, 2007[80] and categorized as "Ready to Respond."[81] These resources only operate for a few hours during peak periods; therefore, they do not contribute significantly to energy prices. However, they do contribute to total capacity and affect the reserve margin and the need for peak capacity. These resources are assumed to continue participation in the ISO's demand response programs that continue until June 2010, at which point the Forward Capacity Market will begin and these resources will be required to bid into the FCM to be eligible as capacity resources. The exhibit below shows the levels of DR that were included in the model in the 2007-2009 time period by zone.

[80] http://www.isonewengland.com/genrtion_resrcs/dr/stats/enroll_sum/2007/lrp_as_of_03-30-2007.ppt.

[81] Ready to Respond means the registration process is complete and the resource is eligible to participate in an event in which the resource may be called upon by the ISO.

Exhibit 5-12. Demand Response Capacity Included in the Model for 2002-2009

Zone	MW
CT	250
SWCT	250
ME	135
NEMA	70
NH	5
RI	5
SEMA	15
VT	20
WCMA	40
Total	790

These resources were modeled as generating units that act as load reduction resources that are committed only if all other available generating resources are operating at full capacity and load is about to be lost. These resources do not set the marginal clearing price. After 2010, existing demand resources that are currently participating in the ISO's DR programs are removed from the energy model as these resources will be required to bid into the capacity market along with other resources and are not guaranteed to continue operating.

ix. Market Model Assumptions

(a) Marginal Cost Bidding

All generation units were assumed to bid marginal cost (opportunity cost of fuel plus variable operating and maintenance costs (VOM) plus opportunity cost of tradable permits). It is reasonable to assume that the real markets are not perfectly competitive and thus the model prices tend to underestimate the prices in the real markets. The energy price outputs were benchmarked against futures prices.

(b) Installed Capacity

Installed capacity requirements of 114.3% of net internal demand are assumed for the New England Power Pool (NEPOOL).

(c) Ancillary Services

Market Analytics allows the user to define generating units based on their ability to participate in various ancillary services markets including Regulation, Spinning Reserves, and Non-Spinning Reserves. The database includes specifications for these abilities based

on unit type. Market Analytics generates prices for these markets in conjunction with the energy market. The spinning reserves market affects energy prices since units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled. The reserves requirements for New England were reviewed and applied to the model.

D. Results

The three charts presented in Exhibits 5-14 to 5-16 illustrate our results using *West-Central Massachusetts* as a representative zone.

Exhibit 5-14 presents our 2007 AESC winter on-peak energy price projections for *West-Central Massachusetts* compared to the 2005 AESC projections for that zone. The "bump" in 2008 on-peak forecast prices as compared to 2007 prices is primarily attributable to the corresponding "bump" in our forecast of Henry Hub prices in 2008, discussed in Chapter 2.

Exhibit 5-13. AESC 2007 vs. AESC 2005 – Winter On-Peak Forecasted Prices

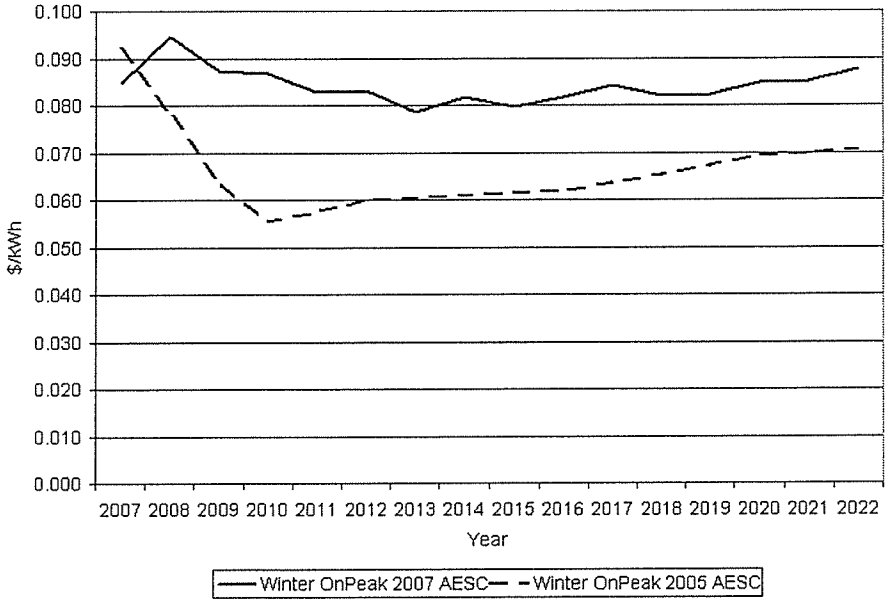


Exhibit 5-15 presents our 2007 AESC winter off-peak energy price projections for *West-Central Massachusetts* and the NYMEX futures for winter off-peak reported for the ISO-NE hub as of May 2, 2007.

Exhibit 5-14. Off-Peak Hub Futures Prices vs. Off-Peak West-Central Massachusetts Forecasted Prices

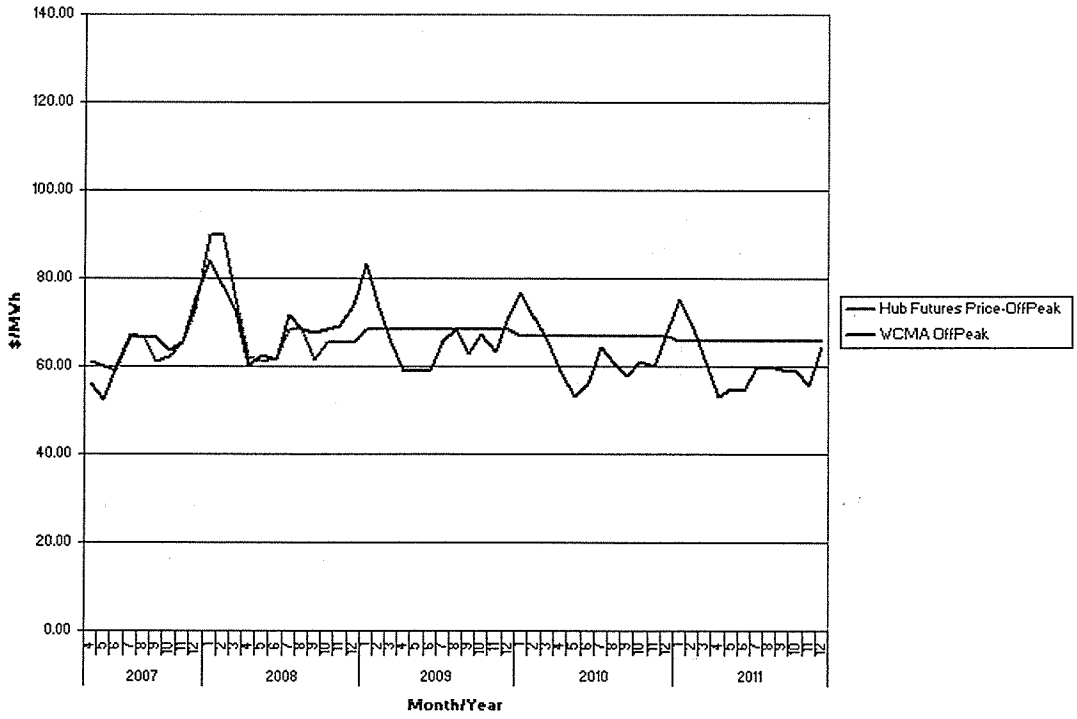
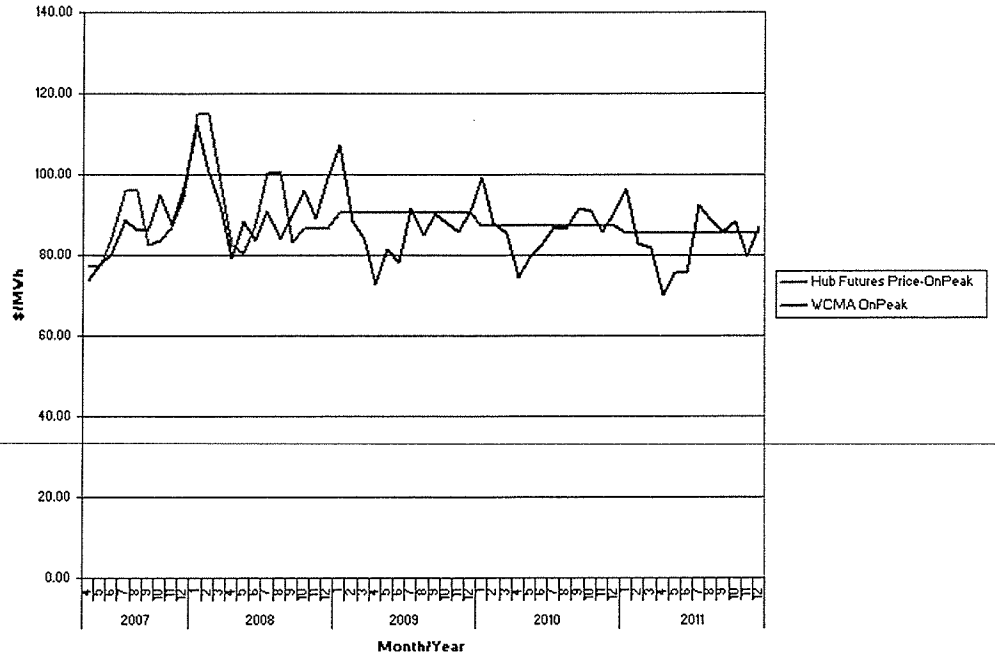


Exhibit 5-15 presents our 2007 AESC winter off-peak energy price projections for *West-Central Massachusetts* and the NYMEX futures for winter off-peak reported for the ISO-NE hub as of May 2, 2007.

Exhibit 5-15. On-Peak Hub Futures Prices vs. On-Peak West-Central Massachusetts Forecasted Prices



Our review of the wholesale energy prices that the modeling initially produced revealed that the projections for certain pricing zones, primarily Vermont and CMA/NEMA, were higher and more volatile than expected. Further analysis indicated that these unexpected results were attributable to "unserved energy"[82] in significantly more hours than the remaining zones. To correct that effect, the price assumed for unserved energy was lowered from $920/MWh, the default value in the model, to $250/MWh, slightly above the highest hourly prices that were generated by supply resources setting the marginal price in New England over the study period. That adjustment reduced the volatility of the zonal prices and produced prices consistent with historical and expected levels.

E. Transmission Energy Losses

Our forecast for marginal energy clearing prices includes inter-area losses for flows across transmission links between modeling zones. These losses are not reported by the

[82] Unserved energy occurs in hours when the model does not have sufficient resources to meet load, and a portion of the forecast load is "unserved" or interrupted. Under those circumstances the model sets the price for that hour in that zone at an assumed price for unserved energy price. The assumed price for unserved energy was set at $920/MWh in the default dataset. Although there were very few hours in which there was unserved energy, the high price assumed for unserved energy skewed the average prices for these zones, resulting in average prices in Vermont to be significantly higher than expected. Because the projections of hours with unserved energy are tied to the projection of outages, whose timing is randomly determined, the high price of unserved energy also had the effect of causing the price streams to be highly volatile.

model by time of day; therefore we have presented the loss factors for summer and winter periods only. The losses presented in Exhibits 5-17 and 5-18 represent losses as a percentage of imports into each zone or state.

Exhibit 5-16. Inter-Area Losses by Modeling Zone as a Percentage of Total Imports

Modeling Zone	Summer	Winter
BHE	5.12%	2.77%
BOST	0.83%	0.64%
CMA	3.15%	3.01%
CMP	0.11%	0.26%
CT	2.30%	1.89%
CTSW	2.00%	2.00%
NH	8.75%	8.66%
RI	0.79%	0.90%
SEMA	0.57%	0.76%
VT	3.29%	3.20%
WEMA	1.23%	1.23%
New England Average	2.31%	2.17%

Exhibit 5-17. Inter-Area Losses by State as a Percentage of Total Imports

State	Summer	Winter
CT	2.11%	1.93%
MA	1.98%	1.86%
ME	1.13%	1.19%
NH	4.61%	4.45%
RI	0.77%	0.89%
VT	2.61%	2.50%
New England Average	2.31%	2.17%

F. Key Sources of Uncertainty in Forecast Energy Prices

The following variables contribute the greatest degree of uncertainty to the final avoided electric supply costs:

- Fuel prices, particularly natural gas prices;
- Carbon emission prices; and
- Capacity prices.

Each of these components makes up a significant share of the total cost of electricity and each is subject to a great deal of uncertainty.

The exhibit below shows the contribution of natural gas prices and carbon prices to the total energy price. The values in this exhibit were based on a combustion turbine with a 10,000 Btu/kWh heat rate operating at the margin. The three carbon prices were approximately equal to the Low, Mid, and High price projections for 2015 in the Synapse carbon price forecast.

Exhibit 5-18. Contribution of Natural Gas Prices and Carbon Prices to the Total Energy Price

Gas Price	Energy Price Fuel Component	Percent of Total Price	Carbon Price	CO_2 Emission Rate	Energy Price Carbon Component	Percent of Total Price	Variable O&M	Total Energy Price
$/MMBtu	$/MWh	%	$/ton	lbs/MMBtu	$/MWh	%	$/MWh	$/MWh
5.00	50.00	91%	5.00	120	3.00	5%	2.00	55.00
6.00	60.00	85%	15.00	120	9.00	13%	2.00	71.00
7.00	70.00	80%	25.00	120	15.00	17%	2.00	87.00

Capacity prices are projected to add an estimated $10-14/MWh to the energy price.[83] At a $71 energy price, the capacity prices make up 12-16% of the total electricity price.

Carbon prices and capacity prices were based on projections of markets that are not yet operating, and therefore there is a great deal of speculation around these prices.

[83] Connecticut Light and Power 2006 reconcilliation filing, March 30, 2007.

6. Avoided Electricity Supply Costs

This chapter provides a projection of avoided electricity costs and a description of the underlying assumptions.

Our avoided electricity supply costs were developed from projections of:

- Generally accepted components of avoided costs including
    - electric energy prices from section 5;
    - avoided costs from the Forward Capacity Market (FCM), adjusted for losses on the ISO-administered pool transmission facilities (PFT); and
    - avoided cost of compliance with RPS, and
- Additional components including
    - a retail adder, reflecting the risks and costs related to power procurement;
    - demand-reduction-induced price effects (DRIPE) for energy and capacity; and
    - environmental externalities.

These avoided electricity supply costs do not include several components of wholesale power costs that we consider to be largely or entirely unavoidable through DSM. These components include the locational forward reserve market, real-time operating reserves, automatic generation control (also called regulation), uplift, and the reliability contracts with particular generators.

As requested in the scope of work, avoided electricity supply costs are provided for the following geographic areas:

- Maine
- Vermont
- New Hampshire
- Connecticut (Statewide)
- Massachusetts (Statewide)
- Rhode Island
- SEMA (Southeast Massachusetts)
- WCMA (West-Central Massachusetts)
- NEMA (Northeast Massachusetts)

- Rest of Massachusetts (Massachusetts excluding NEMA)
- Norwalk/Stamford
- Southwest Connecticut, including Norwalk/Stamford
- Southwest Connecticut, excluding Norwalk/Stamford
- Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

A. Avoided Cost of Compliance with RPS

Our estimate of avoided costs includes the cost of avoiding additional costs under the RPS in the various states that have imposed such standards. In essence, these standards imply that the conventional power-supply mix imposes excessive costs and risks (which may be related to environmental damage, resource depletion, or price volatility), and that the costs of renewables are justified as mitigation. The amount of renewables required is tied to the amount of energy used, so this compliance cost is avoidable, just as the cost of environmental compliance on avoidable energy or new capacity is. Reduction in load due to DSM will reduce the RPS requirements of load serving entities (LSE) and therefore reduce the costs they seek to recover associated with complying with these requirements.

The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

Avoided RPS cost = renewable energy price premium * RPS percentage

So, in a year in which the renewable energy price premium was $50/MWh (or 5 cents/kWh) and the RPS percentage was 10%, the avoided RPS cost to a retail customer would be $0.50 cents/kWh.[84]

It was relatively easy to develop assumptions for RPS percentages by state over the study period, as they are generally specified in legislation or regulations. However, research found relatively few recent public projections of renewable energy price premiums in New England. One measure of that premium is the price at which Renewable Energy Credits (RECs) are trading and are projected to trade in the future. However, to develop an estimate of such a premium one needs to forecast prices in the wholesale energy market over the study period as well as to forecast prices in the market for "new renewables." The difference between these two projections is an estimate of the prices at which RECs will trade.

Due to the absence of a definitive forecast, two methodologies were considered. The first is drawn from a recent study by researchers at the University of New Hampshire.[85] The

[84] 5 cents/kWh * 10%.

[85] Gittell, Ross and Magnusson, Matt; *Economic Impact of a New Hampshire Renewable Portfolio Standard*, University of New Hampshire, February 2007.

second simply assumes that the premium will remain at approximately $50/MWh[86] over the study period, on the assumption that policy makers may decide to increase RPS percentages during the course of the study period, particularly if RECs start trading at much lower prices.

A comparison of the avoided RPS costs resulting from each approach for 2010 and 2020 can be found in the exhibit below.

Exhibit 6-1. Avoided RPS Costs Under Alternative Forecasts of REC Prices (Cents/kWh in $2007)

State	$50/MWh		UNH Report	
	2010	2020	2010	2020
CT	0.35	0.35	0.23	0.00
MA	0.25	0.75	0.17	0.00
ME	0.50	0.50	0.10	0.00
NH	0.05	0.57	0.03	0.00
RI	0.13	0.70	0.08	0.00
VT	0.23	0.50	0.15	0.00

The AESC 2007 projections of avoided electricity costs are based upon the forecast of REC prices presented in the study by researchers at the University of New Hampshire. This methodology was selected because the costs were thought to be more realistic.

B. Avoided Capacity Costs

i. Overview of the Capacity Market

Over the past several years the capacity market in New England has been operating under a set of installed capacity rules designed to ensure sufficient capacity is available to meet projected loads. Following challenges to the merits of that framework, the Federal Energy Regulatory Commission has approved a new framework, the Forward Capacity Market (FCM), which is scheduled to go into effect in June 2010. Until then, a transition period framework is, and will be, in effect.

The transition period from the current installed capacity market to the forward capacity market is December 2006 through May 2010. ISO-NE has set the installed-capacity (ICAP) prices to be paid to suppliers for each power year (June–May) during that period. Those prices are $3.05/kW-month through May 2008, $3.75/kW-month for June 2008 through May 2009, and $4.10/kW-month for June 2009 through May 2010.

[86] This is the range in which RECs are currently trading and of current alternative compliance prices.

Under the FCM, ISO-NE will set the price for capacity each year based upon the results of an auction to be conducted three years in advance. However, the auction for the first FCM year, June 2010 through May 2011, will not be held until February 2008. Later in 2008 ISO-NE will conduct an auction for the second FCM year, June 2011 through May 2012. The basic structure for the auctions has been developed, but some important inputs – especially the amount of capacity that can be imported to each zone – have not been released.

The ISO will establish the FCM price from the auction results. For at least the first three FCM years (June 2010 through May 2013), the price for capacity will be constrained between a minimum and a maximum equal to -40% and +40% of a reference price respectively. The reference price for the first FCM year has been set at $90/kW-yr or $7.50/kW-month.

Suppliers will receive revenues equal to the quantity of capacity they provide times the auction price minus penalties for any failure to perform and minus an estimate of the energy profits (called peak energy rent, or PER) that would be earned by a generator with a 22,000 Btu/kWh.[87] The PER that the hypothetical peaker would earn in each hour will be multiplied by the ratio of load in that hour to the peak load for the power year.

Load will pay costs equal to the quantity of capacity they are required to hold times the auction price, less credits for any supplier penalties and the PER. The quantity of capacity that a particular load is required to hold in each month is based on the contribution of that load to the ISO annual peak. As a result, the total cost of that capacity to that load, i.e., dollars per kW times required kW of capacity, is essentially fixed for an entire FCM year. The unit cost of capacity for a calendar year, $/kW-year, will be the average of five months at the cost for the power year ending in May of that calendar year and seven months for the power year starting in June.

ii. Transition Period Avoided Capacity Cost Forecast (2006 – May 2010)

Due to the fact that consumers must pay for all qualifying ICAP supply during the transition period, none of these capacity costs are avoidable. Public energy-efficiency programs that qualify for capacity payments under the transition period ICAP system will receive revenues that their program administrators can credit back to their retail customers in various ways.

iii. FCM Avoided Capacity Costs (June 2010 onwards)

According to current projections of peak capacity requirements, existing capacity and anticipated new additions, it is expected that New England will need some quantity of new capacity to come on-line in the summer of 2010 in order to maintain the desired reserve margin. Further additions will be required in subsequent years. In this section we describe our estimate of the annual value of potential new DSM programs in terms of avoiding the costs of those new capacity additions from June 2010 onward.

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[87] "Forward Capacity Market Payments, Performance and Charges," ISO-NE, October 11, 2006, p. 9.

The AESC 2007 estimate of avoided capacity costs under the FCM is neither designed, nor intended, to be a forecast of the annual price of capacity in the FCM. Instead, this is an estimate of the annual value of potential new DSM programs in terms of avoided capacity costs from June 2010 onward. The forecast was deliberately designed to estimate the cost of capacity in the FCM *in the absence of any new DSM programs*. This approach is consistent with the methodology that we used to estimate avoided electricity market prices. We understand that capacity prices in the first few years of the FCM will very likely be influenced by the quantity of demand reduction bid by new demand-response and energy-efficiency resources.

Our ability to develop this estimate was complicated by the absence of any empirical evidence or experience with this particular form of capacity auction, e.g., the bidding behavior of existing generators, new supply resources, and new efficiency resources. Thus, this forecast of avoided capacity costs under the FCM prices is inherently more uncertain than a forecast for a more-established market structure.

Given those caveats, our forecast of the unit cost of avoided capacity under the FCM is based on the assumptions listed below. Our approach is also discussed in the context of an illustrative example presented in Exhibit 6-3. Our assumptions are that:

- Most existing generation capacity will bid in as a "price-taker," at or below the minimum FCM price;
- Some existing generation capacity will effectively[88] submit bids somewhat above the minimum FCM price, reflecting their need for incremental capacity revenue to remain viable;
- there will be a substantial need for new capacity to satisfy RPS requirements, even after the bids received from existing generation and conventional new capacity;
- the incremental source of this new capacity will be new peakers;
- The FCM prices will be determined by the price of new peakers;
- The FCM prices will provide developers enough assurance to build enough peakers to meet the ISO-NE regional capability target, but no more; and
- Capacity will be added preferentially in the areas with the lowest reserves and the highest FCM prices, gradually equalizing reserves across the region. Connecticut and NEMA are most likely to have prices higher than average, and Maine is the zone most likely to have FCM prices below average.

The prices paid to generators should approximate the cost of new entry, which is assumed to be the fixed costs of a merchant combustion turbine, net of a conservative estimate of profits from energy sales.[89]

[88] Existing generation owners do not submit regular bids but instead submit "de-list" bids.

The three ISO adjustments to the FCM auction price were treated as follows:

(a) Non-Performance Penalties

Since bidders offering new capacity are likely to increase their bids to cover the expected level of outages and non-performance penalties, it was assumed that the price after non-performance penalties would be similar to the cost of new entry.

(b) Peak Energy Rent

The PER offset is likely to be very small.[90] It was assumed that bidders will increase their bids to cover that small reduction.

(c) Reserve Margin

Each kW of load on the ISO system will be required to support more than a kW of supply. A reserve margin of 14.3% was assumed, plus an allowance for the demand-response resources that were assumed in the determination of the required reserves.

[89] New peakers are also likely to receive some revenues in the forward reserve market (although this would require foregoing some energy revenues) and the real-time reserve market. Since the ISO will reduce the forward reserve price by the forward capacity price, and since the forward capacity auction will be run long before the forward reserve auction, we assume that developers will not reduce their capacity bids based on potential future reserve payments.

[90] Over the period from 2005 to the present, the PER would have been less than $1/kW-year.

iv. Assumed Cost of a New Peaker

The following inputs for the cost of new entry into the forward capacity market were assumed:

Exhibit 6-2. Inputs for the Cost of New Entry into the FCM

Parameter	Value	Source
Total Investment	$800/kW	$700: High end from ISO-NE Stakeholders Analysis Working Group, "Resource Assumptions Revised", 4/4/07 $1,000: Upstate estimate for 2xLM6000, Sargent & Lundy, NYISO ICAP Working Group, "Updated Results and Discussion: Capital Cost and Performance of New Entrant Peaking Unit" 3/22/07
Debt-equity ratio	50:50	
Cost of debt	9%	
Cost of equity	15%	
Debt maturity	20 years	
Fixed O&M	$15/kW-yr	PacifiCorp's West Valley (5xLM6000) O&M was $15/kW for 2005; increase for higher costs in Northeast & overheads; decrease for competitive incentives
Variable O&M	$5/MWh	Sargent & Lundy, op cit
Full-load clean and new heat rate	9,700	Sargent & Lundy, op cit.
EAF	95%	
Income tax rate	40%	
Property tax rate (% of investment)	2%	

The financial inputs were intended to represent the low end of merchant risk, reflecting the fact that the FCM will offer new units the equivalent of five-year fixed-price contracts, but that developers will be at risk for energy and reserve revenues, and for the severe penalties for failure to operate at critical hours. (As noted above, it is anticipated that bidders will take the ISO's energy-revenue credit and non-performance penalties into consideration when developing their bids.)

These inputs resulted in a real-levelized fixed cost of about $130/kW-yr, which would be offset by average net energy revenues of about $30/kW-yr, for a net bid price of about

$100/kW-yr or $8.33/kW-month.[91,92] Increasing that price by a reserve margin of 14.3% results in a forecast cost to consumers of $114/kW-yr, before adjustments for losses.[93]

v. Illustrative Example

In Exhibit 6-3 we present an illustrative example of our approach. The key assumptions underlying this example are as follows:

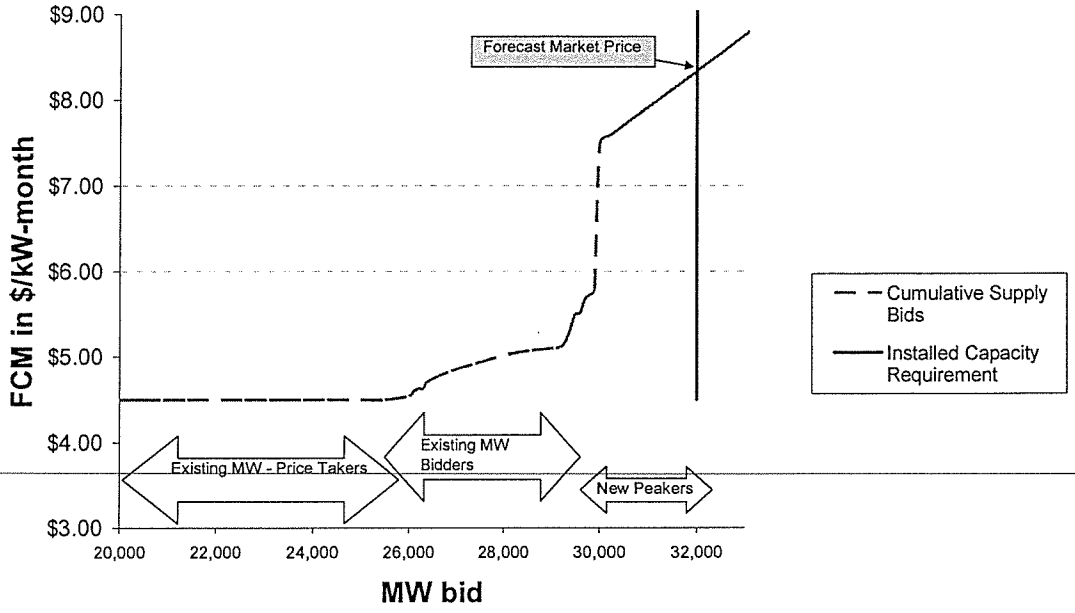
- The Installed Capacity requirement is 32,000 MW.
- The minimum FCM price is $4.50/kW-month
- There is 30,000 MW of existing generation capacity, of which 26,000 MW is bid as a "price-taker," at or below the minimum FCM price, and 4,000 MW effectively submits bids somewhat above the minimum FCM price;
- 2,000 MW of new peakers submit bids, in increments of approximately 200 MW per bid with prices starting at $7.50 per kW-month and increasing by $0.083/kW-monthwith each increment;
- The FCM price is set at $8.33/kW-month based upon the bid of last peaker selected to meet the cumulative need of 32,000 MW.

[91] Some peakers will decide to bid into the forward reserve market. They will receive revenues from this market, but receive less in energy revenues (since they will need to bid into the energy market at more than 14,000 Btu/kWh).

[92] ISO-NE is using an estimate of $7.50/kW-month.

[93] The maximum price under the ISO rules would start at $126/kW-yr in 2010 – 2011 (i.e., 1.4 × $90/kW-yr). Assuming a 5% non-performance penalty and a PER offset of $1/kW-yr and adding the 14.3% reserve margin, the maximum cost to customers would be $136/kW-yr. That price would be paid only if new capacity were more expensive, or less available than expected, or if inadequate transmission among zones resulted in a some zone separating from the rest of the pool.

Exhibit 6-3. Illustrative FCM Price with No DSM Bids



vi. Avoided Capacity Costs of New DSM by Year

As noted above, there is a high level of uncertainty regarding the capacity prices in the first few years of the FCM. Moreover, it is possible that in the early years of the FCM the quantity of demand reduction bid by new demand-response and energy-efficiency resources could be so large as to avoid not only new peakers, but also some lower-cost existing capacity. Based upon those considerations, AESC 2007 is proposing a conservative estimate of avoided capacity-costs. Specifically we are proposing that the avoided capacity cost of new DSM be as follows:

- 80% of a new peaker ($80/kW-yr) in the year starting June 2010;
- 90% of a new peaker ($90/kW-yr) in the year starting June 2011; and
- 100% of a new peaker ($100/kW-yr) in the years from June 2012 onward.

vii. Market Operation

One critical issue in the forecasting of FCM prices is whether prices will be uniform across the ISO, or whether some zones will decouple from the pool and have higher or lower prices. If the ISO sets high capacity transfer limits among zones, it is assumed that the FCM price will be set at the cost of new entry for all zones. If the capacity transfer limits are lower, FCM prices in the early years will stick at the price cap in the most capacity-constrained zones (Connecticut and possibly some Massachusetts zones), while the prices in Maine and possibly Vermont and New Hampshire may be lower than the

cost of new entry.[94] In the absence of any experience with this market, estimating the lower prices is a matter of judgment. Over time, concentration of new resources in the higher-priced zones would tend to eliminate the FCM price differentials among zones.

The ISO committed to finalize the topology (which would include the local sourcing requirements and transfer limits) for the first forward-capacity auction in December 2006 and post the final assumptions early in January 2007.[95] The assumptions used in AESC 2007 are consistent with those posted by the ISO in mid-July 2007. If the capacity transfer limits are the same as the estimates the ISO sponsored in the testimony of David LaPlante in the Locational ICAP Filing,[96] there will be no locational zones in the FCM.[97]

Our forecast of the avoided cost of capacity in the FCM is $100/kW-yr in 2007 dollars, based on the cost of new peakers, from June 2010 through the end of the study period.

viii. Reliability-Must-Run (RMR) Contracts

Our study does not include any avoidable costs for reliability contracts for the reasons outlined herein.

The FCM price projected in this study covers the entire revenue requirement of four of the ten plants described in Exhibit 5-8, so those plants should not require reliability agreements.[98] The combined-cycle plants are likely to earn at least $80/kW-yr of profit in the energy markets, so Berkshire, Milford and Bridgeport Energy should be economic without any special treatment. With the market energy prices projected in this project, and some uplift compensation for cycling, New Haven Harbor should receive more than its revenue requirement or at the very least roughly break even. In addition, the cost of keeping this unit on line is likely to be less than the revenue requirements which the ISO agreed to pay them. That leaves only the West Springfield CTs and Bridgeport Harbor 2 at risk. The FCM should be sufficient to encourage some developer to build new capacity in WCMA, if Con Edison bids West Springfield into the forward capacity auction at a price close to the $161/kW-year revenue requirement. Bridgeport Harbor 2 may no longer be needed after the operation of the Southwest Connecticut transmission upgrade and other changes in the system. At worst, the cost of the remaining reliability contract would be under $5 million for Bridgeport Harbor 2 ($46/kW-year × 130 MW). It is not clear what magnitude of load reductions would avoid the need for Bridgeport Harbor 2.

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[94] The caps are 1.4 × $90/kW-yr, or $126/kW-yr in 2010 – 2011; 1.4 times the average of $90 and the first-year price ($126) or $151/kW-yr in 2011 – 2012; and 1.4 × (.25 × $90 + .75 × ($126 + $151) ÷ 2) = $177/kW-yr in 2012–2013.

[95] "Establishing New England System Topology Assumptions for the Forward Capacity Market," Transmission Owners Meeting, October 19, 2006, p. 4.

[96] FERC Docket No. ER03-563-030, August 31, 2004.

[97] This is also the conclusion of "Report on the Electricity Sector Needs of Connecticut, 2007 – 2021," London Economics International, on behalf of the Connecticut DPUC, August 25, 2006.

[98] As noted above, DSM resources may reduce actual FCM prices in the first few years of the market's operation. If those conditions materialize, some of the RMR generators may request new contracts, creating the opportunity for additional DSM to avoid RMR costs. This factor would tend to offset the reduction in avoidable FCM prices and stabilize the value of DSM.

ix. Comparison to 2005 AESC Estimates of Capacity Costs

The 2005 AESC study, based on the administrative "demand-curve" method then proposed by ISO-NE for setting locational installed capacity prices, estimated capacity prices that varied by year and zone. The levelized capacity prices for 2006–2020 (in 2005 dollars, excluding reserves) were $48/kW-year for Maine, $71/kW-year–$74/kW-year in various parts of Connecticut, $72/kW-year for Boston, and $68/kW-year in other zones. Even with reserves and inflation, the values from the 2005 study are lower than the current estimates, primarily due to the differences in the anticipated ISO capacity markets.

x. Derivation of FCM Load Reduction Credits

When preparing our analysis of the FCM, we estimated the capacity credits that program administrators programs would receive if they bid DSM programs into the forward capacity auction. Those estimated capacity credits are presented in our Avoided Electricity Costs in Appendix E. These revenues reflect our estimates of the approximate levels at which prices will clear in the FCM. Those levels are:

- $80/kW-yr in the year starting June 2010;
- $90/kW-yr in the year starting June 2011; and
- $100/kW-yr in the years from June 2012 onward.

It is important to note that these capacity credit revenues are not a component of the AESC 2007 avoided electricity costs.[99] Instead, we have simply provided this estimate for the convenience of program administrators. For example, regulators may ask program administrators for an estimate of the FCM revenues they expect from the programs they bid into that market.

Our estimation of those credits is based upon our projection of the prices in the FCM and the procedure that ISO-NE will follow to determine credits for load reduction resources from those prices.[100] Under that procedure ISO-NE will determine the credit, i.e., $/kW x kW of load reduction, to provide a load reduction resource based upon its actual performance in two key periods, a summer period of June, July, and August, and a winter period of December and January. In the remaining months the ISO will pay a capacity credit to that resource based on its performance in each of those periods, specifically:

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[99] These revenues are not benefits for New England customers as a whole under the Total Resource Cost (TRC) cost-benefit test, since customers will be paying the FCM charges, as well as getting the benefits of the FCM revenues offsetting DSM costs.

[100] For more detail and the treatment of dispatchable demand-side resources, see "Introduction to Demand Resource Participation in New England's Forward Capacity Market," ISO-NE presentation at the Sheraton Springfield Monarch Place Hotel, February 16, 2007.

- In April, May, September, October, and November, the ISO will pay a credit equal to the resource's average reduction in June, July, and August; and
- In February and March, the ISO will pay a credit equal to the resource's average reduction in December and January.

Exhibit 6-4 summarizes the rules for load-reduction credits:

Exhibit 6-4. Procedure for Determination of Load Reduction Credits

<table>
<tr><th rowspan="2">Type of Demand Resource</th><th colspan="12">Month</th></tr>
<tr><th>Dec</th><th>Jan</th><th>Feb</th><th>Mar</th><th>Apr</th><th>May</th><th>Jun</th><th>Jul</th><th>Aug</th><th>Sep</th><th>Oct</th><th>Nov</th></tr>
<tr><td>"On-Peak"</td><td colspan="2">5 to 7 pm</td><td colspan="2" rowspan="2">Average of Dec & Jan credits</td><td colspan="2" rowspan="2">Average of Jun-Aug credits</td><td colspan="3">1 to 5 pm</td><td colspan="3" rowspan="2">Average of Jun-Aug credits</td></tr>
<tr><td>"Seasonal"</td><td colspan="2">Load>90% forecast winter peak</td><td colspan="3">Load>90% forecast summer peak</td></tr>
</table>

Thus, the actual load reduction that a resource achieves in each of the three summer months of June, July, and August will determine the capacity credit it will receive for the equivalent of 2.67 months, i.e. one summer month plus 1.67 shoulder months. The 1.67 shoulder months represents one-third of the credit for each of the five months whose credit is based upon summer performance. Similarly, the actual load reduction that a resource achieves in each of the two winter months of December and January will determine the capacity credit it will receive for the equivalent of 2 months, i.e. one winter month plus 1 shoulder month. The 1 shoulder month represents one-half of the credit for each of the two months whose credit is based upon winter performance. The FCM values presented in the Avoided Electricity Cost workbook in Attachment D are the effective annual values that a resource will receive for load reduction in each summer month and in each winter month, e.g., summer value ($/kW-month) = 2.67 * xxx $/kW-month; winter value ($/kW-month) = 2.0 * xxx $/kW-month.

C. Adjustment of Capacity Costs for Losses on ISO-Administered Pool Transmission Facilities

There is a loss of electricity between the generating unit and the ISO's delivery points, where power is delivered from the ISO-administered pool transmission facilities (PTF) to the distribution utility local transmission and distribution systems. Therefore, a 1 kilowatt load reduction at the ISO's delivery points, as a result of DSM on a given distribution network, reduces the quantity of electricity that a generator has to produce by 1 kilowatt plus the additional quantity it would have had to generate to compensate for losses.[101]

[101] Computations of avoided costs sometimes assume that only average, and not marginal, losses are relevant at the peak hour. The reasoning for that approach is that changes in peak load will lead to changes in transmission and distribution investment, keeping average percentage losses approximately

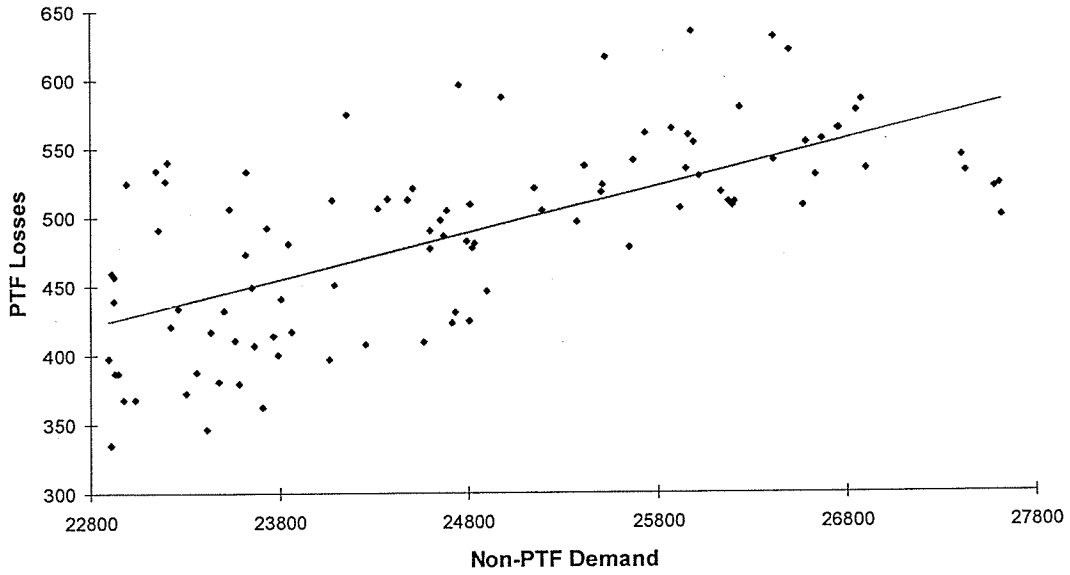
The energy prices forecast by the Market Analytics model reflect these losses. However, the forecast of capacity costs from the FCM do not. Therefore, the forecast capacity costs have to be adjusted for theses losses. We are proposing that they be adjusted by a marginal demand loss factor of 3.38%.

The marginal loss of 3.38% was estimated by regressing the system losses against real-time demand for the top 100 hours in summer 2006 because the ISO does not appear to publish estimates of the losses on the ISO-administered transmission system at system peak. Losses were computed as the difference between ISO-reported values for System Load, which it defines as the sum of generation and net interchange, minus pumping load, and Non-PTF Demand, the term that the ISO uses for the load delivered into the networks of distribution utilities. While PTF losses probably vary among zones, losses by zone could not be identified using the available data.

While there was a large scatter in the data (probably due to plant availability, import availability, and the changing geographical mix of load), there was a clear upward trend in losses with load as shown in the exhibit below.

equal. The AESC 2007 avoided costs do not include any avoided PTF investments, so marginal losses are relevant in this situation.

Exhibit 6-5. PTF Losses vs. Non-PTF Demand for the Top 100 Summer Hours, 2006



The regression equation was PTF Losses = 0.0338 × Non-PTF Demand – 350. While the adjusted R^2 was just 0.44, the marginal demand loss factor of 3.38% had a t-statistic of 8.9 and a 95% confidence interval of 2.6% to 4.1%.

D. Retail Adder

Retail prices for full-requirements fixed-price contracts are generally higher than the sum of wholesale energy and capacity prices during the time period in which the electricity is being consumed. This differential was shown in the 2001 AESC report, and remains in effect today, even after consideration of the cost impacts of ancillary service, uplift, and load shapes.

The primary factor underlying the retail adder appears to be costs suppliers incur to mitigate their risk of under-recovering their costs. These risks arise from the potential for their supply costs to exceed their revenues, i.e., under contracts in which suppliers do not have a "true-up" provision or adjustment to ensure that their revenues equal their costs. The potential for supply costs to exceed revenues arises due to factors such as unexpected variations in weather, economic activity and and/or customer migration. For example, during hot summers and cold winters LSEs may need to procure additional energy at shortage prices while in mild weather they may have excess supply under contract that they need to "dump" into the wholesale market at a loss. The same pattern holds in economic boom and bust cycles. In addition, the suppliers of power for utility standard-service offers run risks related to migration of customer load from utility service to competitive supply (presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss) and from competitive supply to the utility service (at times of high market prices, forcing the supplier to purchase additional power in a high-cost market).

No utility sponsor of this project was able to provide public information on the retail adders implicit in the prices bid by their suppliers. Analyses of confidential supplier bids in other projects suggests that a 10% retail adder is realistic.[102] This adder was applied to the avoided wholesale energy prices and avoided wholesale capacity prices.[103]

The details of the risks and costs of serving load are somewhat different in Vermont and for Public Service of New Hampshire, where vertically-integrated utilities procure power from owned resources and a variety of long- and short-term contracts. It is possible that those utilities face risks similar in nature and magnitude to those of the competitive suppliers for new, marginal supplies. However, we were unable to confirm the nature and magnitude of the risks, and associated costs of risk mitigation, that those utilities face.

E. Demand-Reduction-Induced Price Effects (DRIPE) for Energy and Capacity

The Demand-Reduction-Induced Price Effect (DRIPE) is the reduction in prices in the wholesale energy and capacity markets resulting from the reduction in need for energy and/or capacity due to efficiency and/or demand response programs. This section describes the AESC 2007 estimates of energy DRIPE and capacity DRIPE. Our estimates indicate that the DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. Moreover, we project that those effects will dissipate over four to five years as the market reacts to the new, lower level of energy and capacity required. However, the DRIPE impacts are significant when expressed in absolute dollar terms. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

i. Energy DRIPE

Energy-efficiency measures installed in any one year will have an immediate downward effect on energy prices because the lower load growth will allow lower-cost resources to be at the margin—and set the price—in more hours. This impact is referred to as energy DRIPE. However, those price effects are not likely to persist many years, despite the persistence of energy savings. The lower energy prices will tend to change the mix of generation used to supply the market, which in turn will eventually lead to higher prices erasing the effects of lower loads.

DRIPE in the energy market was estimated based on the following three factors:

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[102] The magnitude of the adder is smaller for near-term procurements than for power procured years in advance, and is higher for congestion into load pockets (such as Connecticut) than for supply to unconstrained areas. The 10% value is a reasonable estimate for the standard-service procurement schedules in most states.

[103] We are unsure how suppliers will structure power supply contracts to capture the risk premium for energy and capacity moving forward. As a result, our recommendation is that the retail adder be applied uniformly to both energy and capacity values.

- The effect of load reduction on market energy prices, if all energy traded in the spot market and the supply system did not change as a result of DRIPE effects;
- The pace at which supply will adapt to energy-efficiency load reductions; and
- The percentage of power supply to retail customers that is subject to market prices in the current year and each future year.

The final DRIPE was the product of the direct effect from the first factor, times the percent of the effect not yet eliminated by supply adaptation from the second factor, times the percentage of power supply that is subject to market prices from the third factor. The DRIPE value may differ by month (or season) and zone.

(a) Effect of Load Reduction on Market Energy Prices

The determination of DRIPE starts with an analysis of the historical variation in locational energy market prices as a function of variation in zonal and regional loads. To minimize the effect of changes in fuel prices, each month was analyzed separately, over a period of at least the last year. Due to the unusual weather in the winter of 2006–2007, analyses from the preceding winter were included.

The basic form of this historical analysis was a regression of day-ahead hourly zonal price in dollars per MWh against both day-ahead load in the zone and day-ahead load in the rest of the ISO control area (rest of pool, or ROP). If one of the resulting coefficients was implausible or insignificant, the zonal price was regressed on total pool load and the resulting coefficient was used for both the own-zone and ROP load. These analyses were performed separately for on- and off-peak hours, since it was expected (and observed) that the slope of market price as a function of load would be higher on-peak.

These results indicate that each additional MW of load in a zone typically increases price in that zone by from 0.4¢/MWh to 4.5¢/MWh, depending on the zone and month. An additional MW of load in the ROP typically increases prices from 0.3¢/MWh to 2.0¢/MWh. The price effect is consistently higher on-peak than off-peak.

The total effect on the regional prices in a particular month, if all transactions moved with the day-ahead market price, would be the sum of the following two components:

- the average hourly load in the zone times the zonal effect, and
- the sum over zones of the average hourly zonal load times the effect of ROP load on that zone.

The coefficients in Exhibit 6-6 result from the on-peak regressions for June 2006.

Exhibit 6-6. Coefficients from June 2006 On-Peak Regressions

	Coefficients $/MWh per MW		Average Hourly Load MWh	Potential DRIPE $/MWh
Zone	Own Load	ROP		
CT	0.0211		4,345	91.8
ME		0.0031	1,419	4.4
NH		0.0040	1,530	6.1
RI		0.0050	1,104	5.5
VT		0.0052	686	3.6
NEMA		0.0068	3,458	23.5
SEMA		0.0049	1,949	9.6
WCMA		0.0037	2,282	8.4
Total				152.8

In this example, reducing Connecticut load one on-peak MWh would reduce regional power bills for the remaining load by about $153, if all prices followed the day-ahead market.

(b) Pace at which Supply will Adapt to Load Reductions

As noted above, a reduction in load will reduce actual and projected prices relative to the levels in the absence of that reduction (the reference case). That reduction in prices will tend to change the mix of generation used to supply the market. This is referred to this as *supply adaptation.* For example, the lower prices due to energy-efficiency investments may cause the following changes in the supply mix:

- A merchant developer may choose to develop a combustion turbine (CT) rather than a combined-cycle (CC) unit, if the CC's reduced energy revenues do not seem likely to cover its additional fixed costs;
- The developer of a potential combined-cycle unit will generally bid a higher price for its capacity (since energy revenues will cover less of the cost), resulting in selection of a combustion turbine in the FCM auction and hence construction of a CT rather than a CC;
- The owner of an old plant (such as a coal plant) that has low variable production costs but requires operational or environmental investments may decide to retire or mothball the plant, due to the lower energy revenues from continued operation;[104] and/or
- The owner of a baseload or intermediate plant may decide to defer spending that would increase its capacity or reliability, since the incremental revenues would not justify the expenditures.

[104] This is not an entirely hypothetical concern, given the costs of upgrading existing coal (and some oil) plants to meet tighter limits on air emissions and (for Brayton Point) use of cooling water.

As the supply mix changes in these and similar ways, energy prices would tend to increase back towards reference case levels. Once this supply adaptation has caused energy prices to recover from the effects of the load reduction, the future decisions by developers, owners and the ISO should be essentially the same as they would have been without the load reduction. Thus, supply adaptation ceases once the price effect has been extinguished.

Supply adaptation will take several years to eliminate all DRIPE, since the supply system cannot immediately respond to the reduction in load. For example, the downward pressure on energy prices due to efficiency measures implemented in one year (e.g., 2009) may not immediately affect expectations of market energy prices. The reductions may only be reflected in decisions to bid FCM capacity in the next year (e.g., 2010) for capacity to be delivered three years later (e.g., 2013).

Estimating the extent of delay in adaptation of the energy market to efficiency-related load reductions is subject to considerable uncertainty. Considering project lead time (including the operation of the FCM market) and past experience with over- and under-building cycles, it is believed that supply adaptation will offset the price effect of DSM over a period of four years after the installation of the measure, with an offset of 0% in years one and two, 35% in year three and 65% in year four.

(c) Share of Retail Power Supply at Current Market Prices

Were all retail power supply provided under cost-of-service pricing or long-term contracts, a short-term reduction in wholesale market prices would have little effect on retail supply prices paid by customers. At the other extreme, if retail customers were being supplied 100% from the spot market and paying spot-market prices, they would experience the benefits of short-term reductions in wholesale market prices fully and immediately. The actual mix of power supply under contract for various periods into the future varies among the states, among the utilities within some states, between municipal utilities and independently owned utilities (IOUs), and between customers on standard utility offer (standard service, default service, last-resort service, etc.) and those served by competitive suppliers. The standard-offer mixes are subject to legislative and/or regulatory change.

The exhibit below summarizes the contracting patterns for power supply by state and type of utility and/or supply arrangement.

Exhibit 6-7. Share of Power Supply Under Contract

	Supply Type	Percent of state load	Share of Power Supply Under Contract[a]		
			1st Year	2nd Year	3rd Year
Connecticut	Standard Service[b]	62%	90%	50%	10%
	SOLR[c]	10%	50%	–	–
	Competitive Supply[d]	25%	80%	50%	20%
	Munis[e]	3%	95%	90%	85%
Maine	Residential[f]	40%	85%	10%	–
	Med & Large C&I[g]	15%	45%	–	–
	Competitive Supply	40%	80%	50%	20%
	Munis & Coops	5%	95%	90%	85%
Massachusetts	NStar + CLC Res & Sm C&I[h]	20%	90%	50%	10%
	Other Res & Sm C&I[i]	20%	70%	–	–
	Large C/I DS[j]	5%	40%	–	–
	Competitive Supply	40%	80%	50%	20%
	Munis	15%	95%	90%	85%
New Hampshire	PSNH[k]	100%	80%	75%	75%
	Other	85%	90%	50%	10%
Rhode Island	NGrid	85%	90%	50%	10%
	Pascoag	100%	95%	95%	95%
	Competitive Supply	62%	90%	50%	10%
Vermont	All	10%	50%	–	–

NOTES

[a] First year is twelve months from measure installation.

[b] Based on the current procurement pattern.

[c] Purchases six months at a time, two months before need, one month lag in load data. Depending on timing, energy-efficiency measures start to affect purchase prices in three to nine months.

[d] Assume mostly three-year large-C&I contracts, some of which will be expiring in each year. Cost under various contract reduced by flow-through of various costs (e.g., congestion). Same pattern assumed for all states.

[e] Assume mostly long-term contracts.

[f] Purchases twelve months at a time, four months before need, one month lag in load data.

[g] Purchases six months at a time, one month before need, one month lag in load data.

[h] The policy is in flux, moving to longer-term procurements. Assumed here to equal the pattern of acquisitions in Connecticut.

[i] Purchases half of requirements for next year every six months. Assume two months before need, one month lag in load data.

[j] Purchases three months at a time, two months before need, one month lag in load data. Depending on timing, energy-efficiency measures start to affect purchase prices in three to six months.

[k] From PSNH's 2005 FERC Form 1, Other Service purchased power (pp. 326–327) net of Other Service sales (pp. 310–311), which was 25% of sales + losses (p. 401). Other Service is for less than one year and/or non-firm. Since some of the Other Service may be contracted for some period within the first year, we assumed 80% was contracted in the first year and 75% thereafter.

In each state, most of the power supply for the immediate twelve months is under contract. In all states except New Hampshire and Vermont, the existing contracts expire over the next couple years, so consumers will be subject to future market prices reflecting the effects of DSM. Exhibit 6-8 summarizes the estimated portion of retail power supplies exposed to market prices, and hence benefiting from the effect of DSM on price, over time.

Exhibit 6-8. Share of Power Supply Exposed to Market Prices

	1st Year	2nd Year	3rd Year	4th Year
Connecticut	16%	54%	86%	98%
Maine	22%	71%	88%	96%
Massachusetts	20%	56%	77%	88%
New Hampshire	20%	25%	25%	25%
Rhode Island	11%	50%	88%	100%
Vermont	5%	5%	5%	5%
Sales-Weighted Regional Average	18%	52%	74%	83%

Multiplying the share of the load exposed to market prices by the portion of the price effect not yet offset by supply adaptation produces an estimate of the percent of load affected by DRIPE. This can be expressed as a formula:

% of load subject to energy DRIPE = (1- supply response) × % of power supply prices at market

Exhibit 6-9 provides, for each state, the result of reducing the share of load exposed to market prices from the exhibit above by the supply response in the first line of the exhibit below.

Exhibit 6-9. Percent of Load Affected by Price Effect

	1st Year	2nd Year	3rd Year	4th Year
Supply Response	0%	0%	35%	65%
Retail DRIPE Effect				
Connecticut	16%	54%	56%	34%
Maine	23%	72%	57%	34%
Massachusetts	20%	57%	50%	31%
New Hampshire	20%	25%	16%	9%
Rhode Island	12%	50%	58%	35%
Vermont	5%	5%	3%	2%
Sales-Weighted Regional Average	18%	52%	48%	29%

Applying those percentages to the potential energy DRIPE produces the energy DRIPE. Continuing with our sample calculation from Exhibit 6-6, we can calculate the energy DRIPE effects of a 1 MWh reduction in energy uses in Connecticut in June 2007. That calculation, presented in Exhibit 6-10, results in an impact of $26/MWh.

Exhibit 6-10. Example Calculation of Energy DRIPE Effects of DSM in CT in June 2007

Zone	Potential DRIPE	Percent of Load affected by Price effect	Price Effects by Zone
	$/MWH	%	$/MWH
	a	b	c = a * b
CT	91.8	16%	14.7
ME	4.4	22%	1.0
NH	6.1	20%	1.2
RI	5.5	11%	0.6
VT	3.6	5%	0.2
NEMA	23.5	20%	4.7
SEMA	9.6	20%	1.9
WCMA	8.4	20%	1.7
Total			26.0
Sources	Exhibit 6-4	Exhibit 6-7	

In Exhibit 6-10 we present our forecast of energy DRIPE effects by zone, year and season, expressed in dollars per MWh saved in each zone.

Exhibit 6-11. Price Effects by Zone (2007$ per MWh Saved)

		Zone							
Year	Season	CT	ME	NH	RI	VT	NEMA	SEMA	WCMA
On-Peak									
1	Summer	33.2	23.7	28.3	24.1	24.5	28.9	31.0	26.1
1	Winter	16.5	15.1	15.2	14.5	14.6	15.2	18.1	15.4
2	Summer	100.2	69.3	75.5	70.3	71.2	84.0	90.1	76.0
2	Winter	48.7	44.1	42.3	42.6	42.1	43.9	52.3	44.5
3	Summer	97.1	65.1	69.4	66.0	66.8	78.2	83.6	71.1
3	Winter	46.3	40.8	39.2	40.3	39.4	40.9	48.4	41.5
4	Summer	59.1	39.5	41.9	40.1	40.6	47.6	50.9	43.2
4	Winter	28.1	24.7	23.7	24.5	23.9	24.9	29.5	25.2
Off-Peak									
1	Summer	16.4	10.1	14.2	10.4	9.8	12.6	12.6	9.7
1	Winter	13.3	12.4	14.4	11.8	11.5	13.1	14.1	11.7
2	Summer	50.5	29.8	34.0	31.4	28.6	36.7	36.7	28.5
2	Winter	39.4	36.5	37.1	34.7	33.5	38.0	41.0	34.1
3	Summer	49.5	27.6	30.1	29.9	26.6	33.8	33.8	26.5
3	Winter	37.3	33.5	33.5	32.6	31.1	35.2	37.8	31.7
4	Summer	30.1	16.7	18.1	18.1	16.2	20.6	20.6	16.1
4	Winter	22.7	20.3	20.2	19.8	18.9	21.4	23.0	19.3

We used the same set of Massachusetts estimates of percentage load affected by price effects for all three Massachusetts zones.

ii. Capacity DRIPE

One would expect that the reduction of load due to efficiency programs should reduce capacity prices in the forward capacity market as well as on electric energy prices in the wholesale energy markets. However, since the forward capacity market will set prices roughly three years in advance, and is likely to be tied closely to the cost of new entry, it is expected that capacity prices will not be very sensitive to small changes in load growth, so long as the growth in load plus retirements of existing capacity continues to require some generic new capacity. Nonetheless, even a small change in market capacity prices could have significant cumulative effects across New England.

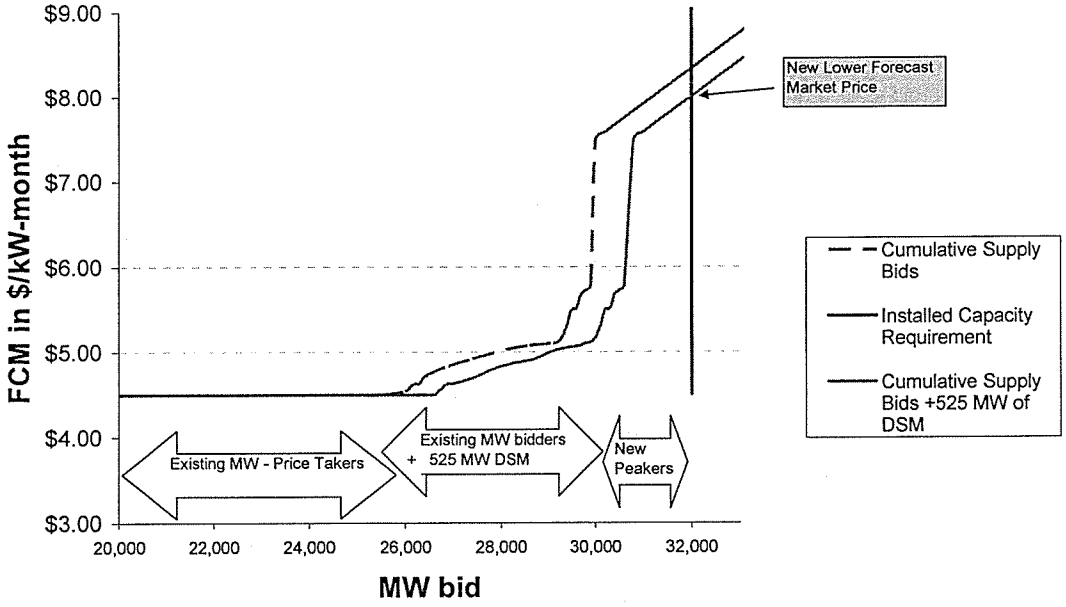
The AESC 2007 approach to estimating capacity DRIPE was fundamentally different from that in the 2005 AESC report because ISO-NE has moved from an ICAP approach to a FCM. At the time of the 2005 AESC report, ISO-NE was proposing an installed-capacity (ICAP) market with prices determined administratively, based on the ratio of capacity resources to peak load. Accordingly, the 2005 report estimated the effect of reduced peak load on the administrative determination of price. Since that time, ISO-NE has abandoned that ICAP market and replaced it with the forward capacity market. DRIPE effects in the FCM are difficult to estimate and are likely to be small.

It is expected that several generating units will bid into, and be selected under, the annual FCM auction (i.e., a supply curve). The cost of the most-expensive unit selected, the marginal new peaking unit, will set the FCM price from that auction. The capacity DRIPE was calculated by estimating the impact of energy-efficiency bid into the FCM on the FCM price. Energy efficiency bid into the FCM would shift the supply curve to the right. The impact of this energy efficiency on FCM prices will very much depend upon the quantity that is bid. If a very small quantity of DSM is bid, the impact on the supply curve may not be large enough to eliminate the need for the marginal new unit and hence there would be no impact on the FCM price. On the other hand, if a very large quantity of DSM is bid, the impact on the supply curve may be large enough to eliminate the need for the most expensive and next most expensive peakers and thereby allow the market to clear at the cost of the third most expensive peaker.

Energy efficiency that is not bid into the FCM will also have a capacity DRIPE effect. However, those effects may be delayed, since the effect on pricing will occur starting with the first FCM auction after implementation, when the DSM reduces load and the ISO reduces the installed-capacity requirement for the capacity auctions two or three years later. In contrast, bid DSM will affect the FCM price for the auction into which it is bid, potentially reducing prices in the year the DSM is implemented.

Our application of this approach can be illustrated by building upon our example of the FCM presented earlier in Exhibit 6-3. In that example, we assumed that new peaker units would submit bids in increments of 200 MW, that the difference between their bid prices would be $1/kW-yr or $0.083/kW-month, and that the FCM would clear at a price of $8.33/kW-month. Now, we consider a second scenario, presented in Exhibit 6-11, in which 525 MW of DSM is bid into the market. That quantity of DSM would effectively shift the supply bid curve to the right by 600 MW, the impact of 525 MW of DSM when adjusted for a reserve margin of 14.3%. In this scenario, the FCM now clears at $8.08/kW-month, a reduction of $0.25/kW-month.

Exhibit 6-12. Illustrative FCM Price with 525 MW of DSM Bids



Based upon these assumptions, each MW of DSM bid into the market would reduce the market-clearing price by an average of $0.0057/MW-year.[105] Thus, each kW of DSM would reduce the market-clearing price by an average of $0.0000057/kW-year. That seems like a minute effect, but it would reduce the price of some 33,000 MW of pool-wide capacity requirement by 2011, for a total potential DRIPE effect of about $190/kW-year of load reduction.[106] We recommend that this estimate be updated by analyzing actual bids once ISO-NE releases the bids received in the FCM auction in 2008.

For the 2008 DSM program year, assuming that the savings are bid into the first FCM auction in February 2008, the capacity DRIPE effect would apply to the power year starting June 2010. Since that effect would only apply to seven months in 2010, and since the analysis that produced the Share of Power Supply Exposed to Market Prices exhibit above suggests that about 65% of ISO load (between the second and third-year results) would be exposed to the market 2½ years into the future, the capacity DRIPE for 2010 might be about $72/kW of load reduction in the 2008 program plan.[107] For 2011, capacity DRIPE might rise to $140/kW for a full year of FCM with less supply (about 25%) under contract.[108] The impacts of efficiency implemented under the 2009 DSM program year would be similar.

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[105] $1/kW-yr ÷ 525 MW = $0.0057/kW-yr per MW of load reduction. We divide by 525 MW, because 175 MW of load reduction, when grossed up by a reserve margin of 14.3%, would avoid the need for 600MW or 3 peakers at 200 MW each.

[106] 33,000,000 kW × $0.000057/kW–yr per kW of load reduction = $190/kW of load reduction.

[107] $190/kW × 65% × 7/12 = $72/kW

[108] $190/kW-yr × 75% = $140/kW-yr.

As difficult as it is to estimate the rate at which the energy market (which has operated in a similar manner for several years and is relatively well understood) will adapt to the addition of energy-efficiency, the FCM market is much harder. The best estimate, using the limited historical experience with response of the capacity markets to over- and under-building situations, is that the FCM DRIPE will dissipate linearly over the fourth and fifth years following the implementation of the energy-efficiency measures. With these assumptions, capacity DRIPE would be as follows:

Exhibit 6-13. Capacity DRIPE by Year and Program Year (2007$/kW)

	DSM Program Year	
Year	2008	2009
2010	$72	
2011	$140	
2012	$90	$140
2013	$40	$90
2014		$40

(d) Comparison to 2005 AESC DRIPE Estimates

The 2005 AESC study estimated capacity DRIPE based on the administrative "demand-curve" method then proposed by ISO-NE for setting locational installed capacity prices. The 2005 AESC study also estimated an alternative capacity DRIPE value, labeled "DRIPE light," reflecting the fact that not all capacity is traded in the spot market. Neither of those DRIPE values anticipated a phase-out of the capacity DRIPE effect over time. Hence, the cumulative capacity DRIPE effects in the 2005 AESC study, with the exception of Maine, were greater than the corresponding effects in AESC 2007 as shown in Exhibit 6-14 below.

Exhibit 6-14. 15 Year Levelized (2008-2022) Capacity DRIPE - AESC 2005 vs. AESC 2007

Zone	AESC 2005	AESC 2007	Change
Maine (ME)	14.37	22.80	59%
Boston (NEMA)	236.91	22.80	-90%
Rest of Massachusetts (non-NEMA)	237.81	24.63	-90%
Central & Western Massachusetts (WCMA)	237.81	24.63	-90%
New Hampshire (NH)	237.81	22.80	-90%
Rhode Island (RI)	237.81	24.63	-90%
Vermont (VT)	237.81	22.80	-90%
Norwalk (NS)	714.09	24.63	-97%
Southwest Connecticut (SWCT)	56.33	22.80	-60%
Rest of Connecticut (non-SWCT)	244.43	24.63	-90%

The AESC 2005 data are the DRIPE 0.75% Capacity Price in 2007$/kW-yr
The AESC 2007 data are the Annual Market Capacity Value from DRIPE for Installations in 2008 in 2007$/kW-yr

The 2007 AESC does not assume that capacity DRIPE will continue indefinitely. However, it is worth noting that the phase-out schedule assumption is simply one estimate from a wide range of reasonable estimates.

7. Environmental Effects

A. Physical Environmental Benefits from Energy Efficiency and Demand Reductions

The scope of work asks for the heat rates, fuel sources, and emissions of NO_x, SO_x, CO_2, and mercury of the marginal units during each of the energy and capacity costing periods in the 2007 base year. It also asks for the quantity of environmental benefits that would correspond to energy efficiency and demand reductions, in lbs/MWh and lbs/kW, respectively, during each costing period.

We began by identifying the marginal unit in each hour in each transmission area. The model reports the marginal unit for each hour in each transmission area. Once the marginal units were identified we drew their heat rates, fuel sources, and emission rates for NO_x, SO_x, CO_2, and mercury from the database of input assumptions used in our Market Analytics simulation of the New England wholesale electricity market. The marginal units and their characteristics are presented in Exhibits 7-1 and 7-2 below.

Exhibit 7-1. 2007 New England Marginal Heat Rate by Pricing Period (Btu/kWh)

	Season & Time of Day				
	Summer		Winter		Grand Total
	OffPeak	OnPeak	OffPeak	OnPeak	
Average Heat Rate	9,245	10,259	9,022	9,808	9,442

Exhibit 7-2. 2007 New England Marginal Fuel Type

	Season & Time of Day				
	Summer		Winter		Grand Total
FuelType	OffPeak	OnPeak	OffPeak	OnPeak	
Gas	63.46%	48.94%	67.36%	53.69%	60.67%
Oil	25.21%	42.56%	25.64%	37.35%	30.78%
DSM	1.34%	7.56%	2.53%	8.96%	4.29%
Coal	7.96%	0.48%	3.91%	0.00%	3.49%
LFG	0.87%	0.46%	0.45%	0.00%	0.47%
Biomass	1.15%	0.00%	0.12%	0.00%	0.30%
Grand Total	100.00%	100.00%	100.00%	100.00%	100.00%

We then calculated the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of lbs/MWh and lbs/kW. We did this by multiplying the quantity of fuel each marginal unit burned by the corresponding emission rate for each pollutant for that type of unit and fuel.

The calculations for each pollutant in each hour are as follows:

- *Marginal Emissions = (Fuel Burned$_{MU}$ (MMBtu) x Emission Rate$_{MU}$ (lbs/MMBtu) x 1 ton/2000 lbs)/Generation$_{MU}$ (MWh)*

Where,

- Fuel Burned$_{MU}$ = the fuel burned by the marginal unit in the hour in which that unit is on the margin,
- Emission Rate$_{MU}$ = the emission rate for the marginal unit, and
- Generation$_{MU}$ = Generation by the marginal unit in the hour in which that unit is on the margin.

The avoided emissions values shown in Exhibits 7-3 through 7-12 below represent the averages for each pollutant over each costing period for all of New England. The first 5 exhibits show the avoided emissions values in short tons/MWh and the second 5 exhibits show the avoided emissions values in short lbs/kWh. We report the emission rates by modeling zone because that is the way that the calculations were done. However, the differences between zones are generally insignificant.

Exhibit 7-3. 2007 New England Summary of Avoided CO_2, NO_x, SO_2 and Mercury (Hg) Emissions Rate by Pricing Period (short tons/MWh)

	Season & Time of Day				
	Summer		Winter		Grand Total
Data	OffPeak	OnPeak	OffPeak	OnPeak	
CO2 (short tons/MWh)	0.66	0.68	0.60	0.61	0.63
NOx (short tons/MWh)	0.00052	0.00074	0.00045	0.00054	0.00054
SO2 (short tons/MWh)	0.0010	0.0014	0.0008	0.0014	0.0010
Hg (short tons/MWh)	9.46E-10	1.12E-11	2.81E-10	0.00E+00	3.27E-10

Exhibit 7-4. 2007 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (short tons/MWh)

CO2 (short tons/MWh)	Season & Time of Day				
	Summer		Winter		Grand Total
Transmission Area	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.67	0.68	0.60	0.60	0.63
NEW ENGLAND - Boston	0.66	0.67	0.60	0.61	0.63
NEW ENGLAND - Central Maine Power Area	0.67	0.68	0.60	0.60	0.63
NEW ENGLAND - Central Massachusetts	0.66	0.67	0.60	0.61	0.63
NEW ENGLAND - Connecticut Central-North	0.66	0.67	0.60	0.60	0.63
NEW ENGLAND - Connecticut Southwest	0.66	0.67	0.60	0.60	0.63
NEW ENGLAND - New Hampshire	0.66	0.68	0.60	0.60	0.63
NEW ENGLAND - Rhode Island	0.66	0.68	0.60	0.61	0.63
NEW ENGLAND - Southeast Massachusetts	0.66	0.67	0.60	0.61	0.63
NEW ENGLAND - Vermont	0.66	0.68	0.60	0.60	0.63
NEW ENGLAND - Western Massachusetts	0.66	0.68	0.60	0.61	0.63
Grand Total	0.66	0.68	0.60	0.61	0.63

Exhibit 7-5. 2007 New England Avoided NO_x Emissions by Modeling Zone and Pricing Period (short tons/MWh)

NOx (short tons/MWh)	Season & Time of Day				
	Summer		Winter		Grand Total
Transmission Area	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.00053	0.00074	0.00045	0.00054	0.00054
NEW ENGLAND - Boston	0.00052	0.00073	0.00045	0.00055	0.00054
NEW ENGLAND - Central Maine Power Area	0.00053	0.00074	0.00046	0.00054	0.00054
NEW ENGLAND - Central Massachusetts	0.00052	0.00073	0.00045	0.00055	0.00054
NEW ENGLAND - Connecticut Central-North	0.00052	0.00075	0.00045	0.00054	0.00054
NEW ENGLAND - Connecticut Southwest	0.00052	0.00074	0.00045	0.00055	0.00054
NEW ENGLAND - New Hampshire	0.00052	0.00074	0.00045	0.00054	0.00054
NEW ENGLAND - Rhode Island	0.00052	0.00073	0.00045	0.00055	0.00054
NEW ENGLAND - Southeast Massachusetts	0.00052	0.00073	0.00045	0.00055	0.00054
NEW ENGLAND - Vermont	0.00052	0.00073	0.00045	0.00054	0.00053
NEW ENGLAND - Western Massachusetts	0.00053	0.00074	0.00045	0.00055	0.00054
Grand Total	0.00052	0.00074	0.00045	0.00054	0.00054

Exhibit 7-6. 2007 New England Avoided SO_2 Emissions by Modeling Zone and Pricing Period (short tons/MWh)

SO2 (short tons/MWh)	Season & Time of Day				
	Summer		Winter		Grand Total
Transmission Area	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.0010	0.0015	0.0008	0.0014	0.0011
NEW ENGLAND - Boston	0.0010	0.0014	0.0008	0.0014	0.0010
NEW ENGLAND - Central Maine Power Area	0.0010	0.0015	0.0008	0.0014	0.0011
NEW ENGLAND - Central Massachusetts	0.0010	0.0014	0.0007	0.0014	0.0010
NEW ENGLAND - Connecticut Central-North	0.0010	0.0013	0.0007	0.0013	0.0010
NEW ENGLAND - Connecticut Southwest	0.0010	0.0013	0.0007	0.0013	0.0010
NEW ENGLAND - New Hampshire	0.0010	0.0015	0.0008	0.0014	0.0011
NEW ENGLAND - Rhode Island	0.0010	0.0014	0.0008	0.0014	0.0010
NEW ENGLAND - Southeast Massachusetts	0.0010	0.0014	0.0007	0.0014	0.0010
NEW ENGLAND - Vermont	0.0010	0.0014	0.0007	0.0013	0.0010
NEW ENGLAND - Western Massachusetts	0.0010	0.0014	0.0007	0.0014	0.0010
Grand Total	0.0010	0.0014	0.0008	0.0014	0.0010

Exhibit 7-7. 2007 New England Avoided Mercury (Hg) Emissions by Modeling Zone and Pricing Period (short tons/MWh)

Hg (short tons/MWh)	Season & Time of Day				
	Summer		Winter		Grand Total
Transmission Area	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	9.52E-10	1.14E-11	2.91E-10	0.00E+00	3.34E-10
NEW ENGLAND - Boston	9.52E-10	1.12E-11	2.92E-10	0.00E+00	3.32E-10
NEW ENGLAND - Central Maine Power Area	9.52E-10	1.11E-11	2.88E-10	0.00E+00	3.31E-10
NEW ENGLAND - Central Massachusetts	9.37E-10	1.13E-11	2.93E-10	0.00E+00	3.31E-10
NEW ENGLAND - Connecticut Central-North	9.43E-10	1.13E-11	2.68E-10	0.00E+00	3.22E-10
NEW ENGLAND - Connecticut Southwest	9.43E-10	1.13E-11	2.68E-10	0.00E+00	3.22E-10
NEW ENGLAND - New Hampshire	9.43E-10	1.11E-11	2.91E-10	0.00E+00	3.31E-10
NEW ENGLAND - Rhode Island	9.43E-10	1.11E-11	2.92E-10	0.00E+00	3.31E-10
NEW ENGLAND - Southeast Massachusetts	9.43E-10	1.13E-11	2.69E-10	0.00E+00	3.22E-10
NEW ENGLAND - Vermont	9.50E-10	1.14E-11	2.68E-10	0.00E+00	3.24E-10
NEW ENGLAND - Western Massachusetts	9.47E-10	1.12E-11	2.69E-10	0.00E+00	3.22E-10
Grand Total	9.46E-10	1.12E-11	2.81E-10	0.00E+00	3.27E-10

Exhibit 7-8. 2007 New England Summary of Avoided CO_2, NO_x, SO_2 and Mercury (Hg) Emissions by Pricing Period (lbs/kWh)

	Season & Time of Day				
	Summer		Winter		Grand Total
Data	OffPeak	OnPeak	OffPeak	OnPeak	
CO2 (lbs/kWh)	1.32	1.35	1.20	1.21	1.26
NOx (lbs/kWh)	0.00105	0.00147	0.00090	0.00109	0.00108
SO2 (lbs/kWh)	0.0020	0.0028	0.0015	0.0028	0.0021
Hg (lbs/kWh)	1.89E-09	2.25E-11	5.62E-10	0.00E+00	6.55E-10

Exhibit 7-9. 2007 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (lbs/kWh)

CO2 (lbs/kWh)	Season & Time of Day				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	1.33	1.36	1.20	1.21	1.26
NEW ENGLAND - Boston	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Central Maine Power Area	1.33	1.35	1.21	1.21	1.26
NEW ENGLAND - Central Massachusetts	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Connecticut Central-North	1.32	1.35	1.20	1.21	1.25
NEW ENGLAND - Connecticut Southwest	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - New Hampshire	1.32	1.36	1.20	1.21	1.26
NEW ENGLAND - Rhode Island	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Southeast Massachusetts	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Vermont	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Western Massachusetts	1.33	1.36	1.20	1.22	1.26
Grand Total	1.32	1.35	1.20	1.21	1.26

Exhibit 7-10. 2007 New England Avoided NO_x Emissions by Modeling Zone and Pricing Period (lbs/kWh)

NOx (lbs/kWh)	Season & Time of Day				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.00105	0.00148	0.00090	0.00108	0.00108
NEW ENGLAND - Boston	0.00104	0.00146	0.00090	0.00109	0.00107
NEW ENGLAND - Central Maine Power Area	0.00105	0.00147	0.00091	0.00107	0.00108
NEW ENGLAND - Central Massachusetts	0.00104	0.00146	0.00090	0.00109	0.00108
NEW ENGLAND - Connecticut Central-North	0.00104	0.00150	0.00090	0.00109	0.00108
NEW ENGLAND - Connecticut Southwest	0.00104	0.00147	0.00090	0.00109	0.00108
NEW ENGLAND - New Hampshire	0.00104	0.00148	0.00091	0.00108	0.00108
NEW ENGLAND - Rhode Island	0.00104	0.00147	0.00091	0.00109	0.00108
NEW ENGLAND - Southeast Massachusetts	0.00104	0.00146	0.00090	0.00109	0.00107
NEW ENGLAND - Vermont	0.00105	0.00146	0.00090	0.00107	0.00107
NEW ENGLAND - Western Massachusetts	0.00105	0.00148	0.00089	0.00109	0.00108
Grand Total	0.00105	0.00147	0.00090	0.00109	0.00108

Exhibit 7-11. 2007 New England Avoided SO_2 Emissions by Modeling Zone and Pricing Period (lbs/kWh)

SO2 (lbs/kWh)	Season & Time of Day				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.0021	0.0029	0.0016	0.0028	0.0021
NEW ENGLAND - Boston	0.0019	0.0028	0.0015	0.0028	0.0021
NEW ENGLAND - Central Maine Power Area	0.0021	0.0029	0.0016	0.0028	0.0021
NEW ENGLAND - Central Massachusetts	0.0020	0.0028	0.0015	0.0028	0.0021
NEW ENGLAND - Connecticut Central-North	0.0019	0.0026	0.0015	0.0026	0.0020
NEW ENGLAND - Connecticut Southwest	0.0019	0.0027	0.0015	0.0026	0.0020
NEW ENGLAND - New Hampshire	0.0020	0.0030	0.0016	0.0028	0.0022
NEW ENGLAND - Rhode Island	0.0020	0.0028	0.0015	0.0028	0.0021
NEW ENGLAND - Southeast Massachusetts	0.0020	0.0028	0.0015	0.0028	0.0021
NEW ENGLAND - Vermont	0.0020	0.0029	0.0015	0.0027	0.0021
NEW ENGLAND - Western Massachusetts	0.0020	0.0029	0.0015	0.0027	0.0021
Grand Total	0.0020	0.0028	0.0015	0.0028	0.0021

Exhibit 7-12. 2007 New England Avoided Mercury (Hg) Emissions by Modeling Zone and Pricing Period (lbs/kWh)

Hg (lbs/kWh)	Season & Time of Day				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	1.90E-09	2.27E-11	5.81E-10	0.00E+00	6.68E-10
NEW ENGLAND - Boston	1.90E-09	2.24E-11	5.84E-10	0.00E+00	6.65E-10
NEW ENGLAND - Central Maine Power Area	1.90E-09	2.23E-11	5.76E-10	0.00E+00	6.62E-10
NEW ENGLAND - Central Massachusetts	1.87E-09	2.26E-11	5.87E-10	0.00E+00	6.62E-10
NEW ENGLAND - Connecticut Central-North	1.89E-09	2.26E-11	5.36E-10	0.00E+00	6.43E-10
NEW ENGLAND - Connecticut Southwest	1.89E-09	2.25E-11	5.36E-10	0.00E+00	6.43E-10
NEW ENGLAND - New Hampshire	1.89E-09	2.23E-11	5.83E-10	0.00E+00	6.61E-10
NEW ENGLAND - Rhode Island	1.89E-09	2.23E-11	5.84E-10	0.00E+00	6.61E-10
NEW ENGLAND - Southeast Massachusetts	1.89E-09	2.25E-11	5.39E-10	0.00E+00	6.44E-10
NEW ENGLAND - Vermont	1.90E-09	2.27E-11	5.37E-10	0.00E+00	6.48E-10
NEW ENGLAND - Western Massachusetts	1.89E-09	2.24E-11	5.39E-10	0.00E+00	6.44E-10
Grand Total	1.89E-09	2.25E-11	5.62E-10	0.00E+00	6.55E-10

B. Monetized Emission Values

The concept of "externalities" is drawn from the field of economics. Externalities are impacts from the production of a good or service that are not reflected in price of that good or service, and that are not considered in the decision to provide that good or service.[109] Air pollution is a classic externality. Pollutants are released from a facility, imposing health impacts on a population, causing damage to an ecosystem, or both. The costs of those health impacts and/or ecosystem damages are not reflected in the price of the product and are not borne by the owner of the pollutant source, and are thus external to the financial decisions pertaining to the source of the pollutant.

i. History of Environmental Externalities – Policies in New England

During the early 1990s, utilities and utility regulators in many states engaged actively in efforts to quantify environmental externalities, and to incorporate consideration of those externalities into utility planning and decision-making. Several of the New England states had proceedings dealing with externalities. In Massachusetts, a pair of related dockets (DPU 89-239 and 91-131) was particularly noteworthy for their timing, litigiousness, and thoroughness. In other states the materials from, and decisions made in, the Massachusetts dockets served as a model, sometimes adapted to the local circumstances and concerns.

In Vermont, for example, the Public Service Board adopted a policy of applying a 5% percentage adder to the cost of generation and transmission resources to reflect environmental externalities and a 10% reduction to the cost of demand side management resources in evaluating resources (VT PSB Order in Docket 5270). Vermont also held a series of workshops to discuss the development of environmental externality values for

[109] In economics, an externality can be positive or negative; in this discussion we are focusing on negative externalities.

Vermont, but that process did not result in a specific set of values. Instead the environmental externality values selected in Massachusetts were adopted for use in Vermont in a series of Company-specific settlement agreements.

The Massachusetts efforts to address environmental externalities will be discussed briefly here, with a focus on carbon dioxide emissions. Docket DPU 89-239 was opened to develop "Rules to Implement Integrated Resource Planning" (IRP) and included consideration of many aspects of IRP including determination and application of environmental externalities values. In its order in that docket, the Department adopted a set of dollar values for air emissions based upon testimony by Bruce Biewald, a witness for the Division of Energy Resources. The CO_2 value adopted in that order was $22 per ton of CO_2 (in 1989$) and was based upon a "target" approach.[110]

The Department of Public Utilities (DPU) in Massachusetts subsequently opened Docket DPU 91-131 specifically to examine environmental externalities. In this docket there were 25 parties, with 21 witnesses testifying over 15 hearing days. The DPU heard testimony recommending various approaches for quantifying the CO_2 externality value, including Dr. William Nordhaus testifying on behalf of Massachusetts Electric Company recommending a "damage cost approach," Bruce Biewald testifying on behalf of the Massachusetts Division of Energy Resources, and Paul Chernick testifying on behalf of Boston Gas Company, both recommending a "sustainability target approach."

Biewald presented a report which outlined the different methods for monetizing externalities, and recommended $23 per ton of CO_2 (in 1990 dollars).[111]

The Department's Order in Docket DPU 91-131 was noteworthy for its foresight regarding climate change, albeit optimistic about the timing of recognition of climate change into policies and regulation in the United States. The Department, in its November 10, 1992 order, concluded:

> The record in this docket indicates that the scientific community believes that continued CO_2 emissions will raise global temperatures significantly, with potentially significant damage to many aspects of society. CO_2 currently is not regulated in the United States, but efforts are underway in the United States and internationally to develop regulations to reduce emissions of CO_2 in the atmosphere. The generation of electricity contributes significantly to the buildup of CO_2 in the atmosphere. The electricity generation industry is likely to be substantially affected by efforts to regulate, tax, or otherwise limit emissions of CO_2. Clearly, it would be prudent for current and future suppliers of electricity to anticipate that CO_2 regulations will be promulgated in the United States and/or internationally in the future, and that such regulations will affect resource options which might be considered in IRM resource solicitations.

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[110] Exh. DOER-3, Exh. BB-2, p. 26.

[111] "Valuation of Environmental Externalities: Sulfur Dioxide and Greenhouse Gases," by Bruce Biewald, Stephen Bernow, Kevin Gurney, Michael Lazarus, and Kristin Wulfsberg. Tellus Institute, December 13, 1991.

> The Department has recognized the large degree of uncertainty associated with estimating (1) the future damages from CO_2 emissions and (2) the future costs to control or otherwise regulate CO_2 emissions. The parties in this proceeding agree that estimating the net damages associated with expected global warming is fraught with uncertainty. They disagree, however, about how much uncertainty should be attached to estimates of future global warming. They disagree even more on the likely damages from future global warming. Consequently, the Department has been presented with a wide range of estimated external cost values for CO_2, from a negative value to many times the current value.[112]
>
> In this case, the Department will determine whether it has been demonstrated that any proposed damage estimates for CO_2 are comprehensive and reliable, or, if not, are more reasonable than the Department's current value. [113]

Based on information in the record, the Department reaffirmed the CO_2 value it had adopted in the previous case, $22 per ton (in 1989 dollars).[114]

One of the important dynamics that can be observed in the evolution of environmental policies is the time lag between (1) the recognition of an environmental or health hazard, (2) the scientific study and documentation of the impacts, (3) the development and implementation of regulations to address the harm, and (4) the adjustment of the regulations to recognize evolving understanding of the impacts and the changing political consensus. The history of acid rain regulation provides a good example of this time lag. Acid rain was recognized as early as the mid-nineteenth century in England; however, it wasn't until the 1960s that the science and impacts of acid rain were widely studied. In 1980 Congress established a ten year research program, the National Acidic Precipitation Assessment Program to understand and quantify acid rain impacts. The Clean Air Act Amendments of 1990 included provisions for SO_2 emission caps to be implemented beginning in 1995 ("phase 1") for the largest sources, and 2000 ("phase 2") for other sources. More recently, the Clean Air Interstate Rule, passed by Congress in March 2005, adjusts the SO_2 emissions cap downward with an ultimate effect of reducing SO_2 emissions about 73% from 2003 levels, in order to address severe interstate pollutant transport issues that were not effectively addressed by prior regulation.

Action to address the depletion of the stratospheric ozone layer was more rapid, demonstrating the international community's ability to act relatively swiftly when convinced that urgent action is required. In the early 1970s two scientists identified compounds that were depleting the ozone layer; by 1985 scientists had observed and documented an "Antarctic Ozone Hole" during springtime. In 1987 international action resulted in the negotiation of the Montreal Protocol to regulate the use and production of ozone-depleting substances. In terms of climate change and carbon dioxide regulations in the United States, we are currently at the early stages of a similar ongoing and evolving

[112] DPU 86-36-G, pp.86-87

[113] DPU 86-36-G, pp.73-74

[114] DPU 86-36-G, pp.76

process. The regulatory history of acid rain and of ozone depletion contributed important foundations for efforts to regulate greenhouse gas emissions (federal government role in addressing pollution, and framework for international negotiations on pollutants, respectively).

ii. Carbon Dioxide will be the Dominant Externality from Electricity Production and Use in New England Over the Study Period

Externalities associated with electricity production and uses include a wide variety of air pollutants, water pollutants, and land use impacts. The principle air pollutants that have externalities include carbon dioxide, sulfur dioxide, nitrogen oxides and ozone, particulates, and mercury.

There have been several fairly comprehensive studies that assess the full range of environmental impacts from electricity generation and use. These include:

- *Environmental Costs of Electricity*, prepared by the Pace University Center for Environmental and Legal Studies: Ottinger, R, et. al,, for NYSERDA, Oceana Publications, Inc, 1990;
- The New York State Environmental Externalities Cost Study, RCG/Hagler, Bailly, Inc. and Tellus Institute, for the Empire State Electric Energy Research Corporation (ESEERCO), multiple volumes, 1994 and 1995;
- Non-Price Benefits of BECo Demand-Side Management Programs, for the Boston Edison Settlement Board, Tellus No. 93-174A, July 1994; and
- US-EC Fuel Cycle Study, by Oak Ridge National Laboratory and Resources for the Future, for the US Department of Energy and the Commission of the European Communities, multiple volumes, 1992 to 1994.

The list of externalities from energy production and use is quite long, and includes the following:

- Air emissions (including SO_2, NO_x, particulates, mercury, lead, other toxins, and greenhouse gases) and the associated health and ecological damages;
- Fuel cycle impacts associated with "front end" activities such as mining and transportation, and waste disposal;
- Water use and pollution;
- Land use;
- Aesthetic impacts of power plants and related facilities;
- Radiological exposures related to nuclear power plant fuel supply and operation (routine and accident scenarios); and
- Other non-environmental externalities such as economic impacts (generally focused on employment), energy security, and others.

Many of these externalities have been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of those costs in their production and use decisions, thereby "internalizing" a portion of those costs. For example, the Clean Air Interstate Rule, passed by Congress in March 2005, adjusts the SO_2 emissions cap downward with an ultimate effect of reducing SO_2 emissions about 73% from 2003 levels. The Clean Air Act and the Clean Air Interstate Rule require further reductions in emission levels over the study period. As a result, while there remain some "external costs" associated with the residual NO_x and SO_2 pollution, these externalities are now relatively small. In contrast, regulators are just starting to "internalize" the impacts of carbon dioxide.

It is expected that the "carbon externality" will be the dominant externality associated with marginal electricity generation in New England. This is the case for two main reasons. First, as noted above, regulations to address the greenhouse gas emissions responsible for global climate change are lagging, particularly in the United States. The damages from criteria air pollutants are relatively bounded, and to a great extent "internalized," as a result of existing regulations. In contrast, global climate change is a problem on an unprecedented scale with far-reaching and potentially catastrophic implications. Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal SO_2, mercury, and particulate emissions and relatively low NO_x emissions. Hence, spending extensive time reviewing the latest literature on externality values for these emissions would not be a good use of time and budget. Based on knowledge of the electric system, and review of model runs, it is believed that the dominant environmental externality in New England over the study period will be the un-internalized cost of carbon dioxide emissions. RGGI and any federal CO_2 regulations will only internalize a portion of the "greenhouse gas externality," particularly in the near term.

The California PUC has directed electric companies to include a value for carbon dioxide in their avoided cost determination and long-term resource procurement. The CA PUC found:

> "In terms of specific pollutants, of significant concern to regulators and the public today is the environmental damage caused by carbon dioxide (CO_2) emissions—an inescapable byproduct of fossil fuel burning and by far the major contributor to greenhouse gases. Unlike other significant pollutants from power production, CO_2 is currently an unpriced externality in the energy market.... CO_2 is not consistently regulated at either the Federal or State levels and is not embedded in energy prices...."[115]

For the above reasons, values were developed for the one major emission associated with avoided electricity costs for which the near-term internalized cost most significantly understates the value supported by current science.

[115] R.04-04-003, Appendix B, p. 5.

iii. General Approaches to Monetizing Environmental Externalities

There are various methods available for monetizing environmental externalities such as air pollution from power plants. These include various "damage costing" approaches that seek to value the damages associated with a particular externality, and various "control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant (thus internalizing a portion or all of the externality).

The "damage costing" methods generally rely on travel costs, hedonic pricing, and contingent valuation in the absence of market prices. These are forms of "implied" valuation, asking complex and hypothetical survey questions, or extrapolating from observed behavior. For example, data on how much people will spend on travel, subsistence, and equipment, can be used to measure the value of those fish, or more accurately the value of *not* killing fish via air pollution. Human lives are sometimes valued based upon wage differentials for jobs that expose workers to different risks of mortality. In other words, comparing two jobs, one with higher hourly pay rate and higher risk than the other can serve as a measure of the compensation that someone is "willing to accept" in order to be exposed to the risk.

There are myriad problems with these approaches, two of which will be discussed here. First, the damage costing approaches are, in the case of global climate change, simply subject to too many problematic assumptions. We do not subscribe to the view that a reasonable economic estimate of the "damages" around the world can be developed and used as a figure for the externalities associated with carbon dioxide emissions. In other words, estimating damage is a moving target – it depends upon what concentrations we ultimately reach (or what concentrations we reach and reduce from). This is exacerbated by the fact that we do not fully understand climate change, and cannot project with certainty the levels at which certain impacts will occur. A further complicating factor is that different emissions concentrations create different damages for different regions and different groups of people. Thus, such exercises, while interesting, are fraught with difficulties including: (a) identifying the categories of changes to ecosystems and societies around the planet; (b) estimating magnitudes of impacts; (c) valuing those impacts in economic terms; (d) aggregating those values across countries with different currency exchange rates and different cultures; (e) addressing the non-linear and catastrophic aspects of the climate change damage; and (f) dealing with the paradoxes and conundrums involved in applying financial discount rates to effects stretching over centuries. Second, the fact that the "regulators' revealed preferences" approach is unavailable, as regulators have not established relevant reference points, complicates the task of determining a carbon externality cost.

The "control cost" methods generally look at the *marginal* cost of control. That is, the cost of control valuations look at the last (or most expensive) unit of emissions reduction required to comply with regulations. The cost of control approach can be based upon a "regulators' revealed preference" concept. That is, if "air regulators" are requiring a particular technology with a cost per ton of $X to be installed at power plants, then this can be taken as an indication that the value of those reductions is perceived to be at or above the cost of the controls. The cost of control approach can also be based upon a "sustainability target" concept. With the sustainability target, we start with a level of

damage or risk that is considered to be acceptable, and then estimate the marginal cost of achieving that target.

The "sustainability target" approach relies on the assumption that the nations of the world will not tolerate unlimited damages. It also relies partly on an expectation that policy leaders will realize that it is cheaper to reduce emissions now and achieve a sustainability target than it is not to address climate change. It is worth noting that a cost estimate based on a sustainability target will be a bit lower than a damage cost estimate because the "sustainability target" is going to be a calculus of what climate change the planet is already committed to, and what additional change we are willing to live with (again complicated by the fact that different regions will see different impacts, and have different ideas about what is dangerous and what is sustainable). While we do not use a damage cost estimate, it is informative to consider damages to get a sense of the scale of the problem. In October 2006 a major report to Prime Minister Tony Blair stated that "the benefits of strong and early action far outweigh the economic costs of not acting." Based on its review of results from formal economic models, the Stern Review on the Economics of Climate Change estimated that in the absence of efforts to curb climate change, the overall costs and risks of climate change will be equivalent to losing at least 5% of global GDP each year, now and forever, and could be as much as 20% of GDP or more. In contrast, the Stern Review states that the costs of action – the cost of implementing actions to curb climate change – can be limited around 1% of global GDP each year.[116]

iv. Estimation of CO_2 Environmental Costs

Based upon our review of the merits of those various approaches, we selected an approach that estimates the cost of controlling, or stabilizing, global carbon emissions at a "sustainable level" or sustainability target. To develop that estimate, the most recent science regarding the level of emissions that would be sustainable was reviewed, as well as the literature on costs of controlling emissions at that level.

The conceptual and practical challenges for estimating a carbon externality price include the following:

- The damages are very widely distributed in time (over many decades or even centuries) and space (across the globe);
- The "physical damages" include some impacts that are very difficult to quantify and value, such as flooding large land areas; changes to local climates; species range migration; increased risk of flood and drought; changes in the amount, intensity, frequency, and type of precipitation; changes in the type, frequency, and intensity of extreme weather events (such as hurricanes, heat waves, and heavy precipitation);

[116] Stern, Sir Nicholas; *Stern Review of the Economics of Climate Change*; Cambridge University Press, 2007.

- This list of "physical damages" includes some that are extremely difficult, perhaps impossible, to reasonably express in monetary terms;
- The scientific understanding of the climate change process and climate change impacts is evolving rapidly;
- There may well be reasons (not considered here) that the environmental cost value could have a shape that starts lower and increases faster, or vice versa, having to do with periods in which rates of change are most problematic;
- The scale of the impact on the world economies associated with the impacts of climate change and/or associated with the transformations of economies to reduce greenhouse gas emissions are so large that using terms and concepts such as "marginal" can be problematic; and
- The impacts of climate change are non-linear and non-continuous, including "feedback cycles" that can most reasonably be thought of in terms of thresholds beyond which there are "run away damages" such as irreversible melting of the Greenland ice sheet and the West Antarctic ice sheet, and collapse of the Atlantic thermohaline circulation – a global ocean current system that circulates warm surface waters.

Given the daunting challenge of valuing climate damages in economic terms, AESC 2007 takes a practical approach consistent with the concepts of "sustainability" and "avoidance of undue risk." Specifically, the carbon externality can be valued by looking at the marginal costs associated with controlling total carbon emissions at, or below, the levels that avoid the major climate change risks according to current expectations.

Nonetheless, because the environmental costs of energy production and use are so significant, and because the climate change impacts associated with power plant carbon dioxide emissions are urgently important, it is worthwhile to attempt to estimate the externality price and to put it in dollar terms that can be incorporated into electric system planning.

(a) What is the Correct Level of CO_2 Emissions?

In order to determine what is currently deemed a reasonable sustainability target, current science and policy was reviewed. In 1992, over 160 nations (including the United States) agreed to "to achieve stabilization of atmospheric concentrations of greenhouse gases at levels that would prevent dangerous anthropogenic (human-induced) interference with the climate system...." (United Nations Framework Convention on Climate Change or UNFCCC).[117] Achieving this commitment requires determining the maximum temperature increase above which impacts are anticipated to be dangerous, the atmospheric emissions concentration that is likely to lead to that temperature increase, and the emissions pathway that is likely to limit atmospheric concentrations and temperature increase to the desired levels.

[117] There are currently over 180 signatories.

The definition of what level of temperature change constitutes a dangerous climate change will ultimately be established by politicians, as it requires value judgments about what impacts are tolerable regionally and globally.[118] We expect that such a definition and decision will be based upon what climate science tells us about expected impacts and mitigation opportunities.

While uncertainty and research continue, a growing number of studies identify a global average temperature increase of 2°C above pre-industrial levels as the temperature above which dangerous climate impacts are likely to occur.[119] Temperature increases greater than 2°C above pre-industrial levels are associated with multiple impacts including sea level rise of many meters, drought, increasing hurricane intensity, stress on and possible destruction of unique ecosystems (such as coral reefs, the Arctic, alpine regions), and increasing risk of extreme events.[120] The European Union has adopted a long-term policy goal of limiting global average temperature increase to 2°C above pre-industrial levels.[121]

Because of multiple uncertainties, it is difficult to define with certainty what future emissions pathway is likely to avoid exceeding that temperature increase. We reviewed several sources to determine reasonable assumptions about what level of concentrations are deemed likely to achieve the sustainability target, and what emission reductions are necessary to reach those emissions levels. The Intergovernmental Panel on Climate Change's most recent Assessment Report indicates that concentrations of 445-490 ppm CO_2 equivalent correspond to 2° – 2.4°C increases above pre-industrial levels.[122] A comprehensive assessment of the economics of climate change, The Stern Review, proposes a long-term goal to stabilize greenhouse gases at between the equivalent of 450 and 550 ppm CO_2.[123] Recent research indicates that achieving the 2°C goal likely requires stabilizing atmospheric concentrations of carbon dioxide and other heat-trapping gases near 400 ppm carbon dioxide equivalent.[124]

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[118] For multiple discussions of the issues surrounding dangerous climate change, *see* Schnellnhuber, Cramer, Nakicenovic, Wigley and Yohe, editors; *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006. This book contains the research presented at The International Symposium on Stabilisation of Greenhouse Gas Concentrations, Avoiding Dangerous Climate Change, which took place in the U.K. in 2005.

[119] Mastrandrea, M. and Schneider, S.; *Probabilistic Assessment of "Dangerous" Climate Change and Emissions Scenarios: Stakeholder Metrics and Overshoot Pathways;* Chapter 27 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006.

[120] Schnellnhuber, 2006.

[121] The European Union first adopted this goal in 1996 in "Communication of the Community Strategy on Climate Change." Council conclusions. European Council. Brussels, Council of the EU. The EU has since reiterated its long-term commitment in 2004 and 2005 (*see, e.g.* Council of the European Union, Presidency conclusions, March 22-23.)

[122] IPCC AR4, WGIII Summary for Policy Makers, 2007. Table SPM5.

[123] Stern, Sir Nicholas; *Stern Review of the Economics of Climate Change*; Cambridge University Press, 2007.

[124] Meinshausen, M.; *What Does a 2°C Target Mean for Greenhouse Gases? A Brief Analysis Based on Multi-Gas Emission Pathways and Several Climate Sensitivity Uncertainty Estimates;* Chapter 28 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006.

The Intergovernmental Panel on Climate Change (IPCC) indicates that reaching concentrations of 450-490ppm CO_2-eq requires reduction in global CO_2 emissions in 2050 of 85-50% below 2000 emissions levels. [125] The Stern Review indicates that global emissions would have to be 70% below current levels by 2050 for stabilization at 450ppm CO_2-eq.[126] To accomplish such stabilization, the United States and other industrialized countries would have to reduce greenhouse gas emissions on the order of 80 – 90% below 1990 levels, and developing countries would have to achieve reductions from their baseline trajectory as soon as possible.[127] In the United States, several states have adopted state greenhouse gas reduction targets of 50% or more reduction from a baseline of 1990 levels or then-current levels by 2050 (California, Connecticut, Illinois, Maine, New Hampshire, New Jersey, Oregon, and Vermont). In 2001, the New England states joined with the Eastern Canadian Premiers in also adopting a long-term policy goal of reductions on the order of 75-80% of then-current emission levels.[128]

The sobering news is that a long term stabilization goal of even 400 ppm might not be sufficient: "while very rapid reductions can greatly reduce the level of risk, it nevertheless remains the case that, even with the strictest measures we model, the risk of exceeding the 2°C threshold is in the order of 10 to 25 per cent."[129] Similarly, the 2°C threshold may not be sufficient to avoid severe impacts.[130]

(b) What is the Cost of Stabilizing CO_2 Emissions at this Sustainable Level?

There have been several efforts to estimate the costs of achieving a variety of atmospheric concentration targets. The most comprehensive effort is the work of the Intergovernmental Panel on Climate Change. The IPCC was established by the World Meteorological Organization and UNEP in 1988 to provide scientific, technical and methodological support and analysis on climate change. IPCC has issued three assessment reports on the science of climate change, climate change impacts, and on mitigation and adaptation strategies (1990, 1995, 2001), and is currently issuing its fourth assessment report. In its fourth Assessment Report, the IPCC indicates that reductions on the order of 34 gigatonnes (Gt) would be necessary to achieve an 80% reduction below current. [131] That report estimates that up to 31 Gt in reductions are available for $100/te of

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[125] IPCC AR4, WGIII Summary for Policy Makers, 2007. Table SPM5.

[126] Stern Review, Long Executive Summary, 2007. Page xi.

[127] den Elzen, M., Meinshausen, M; *Multi-Gas Emission Pathways for Meeting the EU 2°C Climate Target;* Chapter 31 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006. Page 306.

[128] New England Governors/Eastern Canadian Premiers, *Climate Change Action Plan 2001*, August 2001. NEG/ECP reiterated this commitment in June 2007 through Resolution 31-1, which states, in part, that the long term reduction goals should be met by 2050.

[129] Bauer and Mastrandrea; *High Stakes: Designing emissions pathways to reduce the risk of dangerous climate change;* Institute for Public Policy Research, U.K.; November 2006.

[130] See recent research by James Hansen, Goddard Space Flight Institute – NASA's top climate scientist.

[131] 2000 emissions levels were 43Gt CO_2-eq. IPCC AR4, WGIII, Summary for Policy Makers, 2007. Page 11.

CO_2 or less (Working Group III Summary for Policy Makers). Other studies on the costs of achieving stabilization targets include the following:

- A Vattenfalls study of abatement potential estimates that about 30 Gt reduction would be necessary for stabilization at 450 ppm, and about 27Gt are available for around \$50/tCO_2 – so cost would go above \$50/t;[132]
- McKinsey & Company have developed an abatement cost curve that indicates that stabilization at 450 ppm would have a marginal abatement cost of about \$50/t, stabilization at 400 ppm would have a marginal abatement cost of over \$60/tCO_2; and
- The Stern Review itself talks primarily about macro-economic costs; however an underlying meta-analysis of modeling literature concludes that "even stringent stabilization targets can be met without materially affecting world GDP growth, at low carbon tax rates or permit prices, at least by 2030 (in ~~\$US(2000), less than \$15/tCO_2 for 550ppmv and \$50/tCO_2 for 450ppmv for~~ CO_2)."[133]

The IPCC Working Group III Summary for Policy Makers states on page 29 (references omitted): "An effective carbon-price signal could realize significant mitigation potential in all sectors.

- Modeling studies show carbon prices rising to 20 to 80 US\$/tCO_2-eq by 2030 and 30 to 155 US\$/tCO_2-eq by 2050 are consistent with stabilization at around 550 ppm CO_2-eq by 2100. For the same stabilization level, studies since the Third Assessment Report that take into account induced technological change lower these price ranges to 5 to 65 US\$/tCO_2eq in 2030 and 15 to 130 US\$/tCO_2-eq in 2050.
- Most top-down, as well as some 2050 bottom-up assessments, suggest that real or implicit carbon prices of 20 to 50 US\$/tCO_2-eq, sustained or increased over decades, could lead to a power generation sector with low-greenhouse gas emissions by 2050 and make many mitigation options in the end-use sectors economically attractive."

Based on a review of these different sources, we believe that it is reasonable to anticipate a marginal cost of control of \$60/tCO_2-eq for achieving a stabilization target that is likely to avoid temperature increases higher than 2°C above pre-industrial levels. Of course, selection of this value requires multiple assumptions.

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[132] *Vattenfalls Global Climate Impact Abatement Map*, accessed May 30, 2007.

[133] Barker, Terry et. al.; *A report prepared for the HM Treasury Stern Review on "The economics of climate change" The Costs of Greenhouse Gas Mitigation with Induced Technological Change: A Meta-Analysis of Estimates in the Literature*; 4 CMR, University of Cambridge. July 2006.

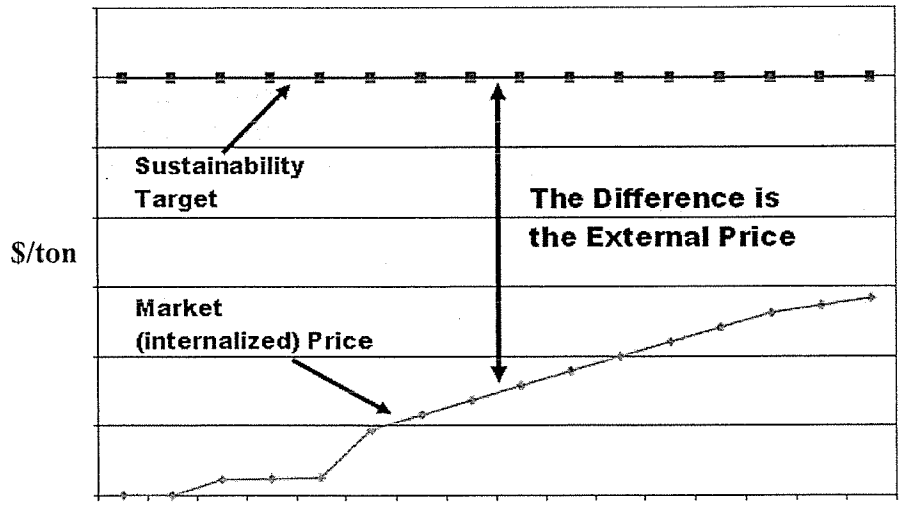
v. Estimating CO_2 Environmental Costs for New England

Our estimates of the "external" or additional cost associated with emissions of carbon dioxide in New England are based upon the sustainability target and the forecast of carbon emission regulation in New England over the study period. The externality value for carbon dioxide in each year was calculated as the estimated annual sustainability target value of $60/ton minus the annual allowance values internalized in the projected electric energy market prices.

The annual allowance values internalized in the projected electric energy market prices are described in Chapter 5. These values are based upon a Synapse forecast of the carbon trading price associated with anticipated carbon regulations. That carbon price was included in the dispatch model runs (in the generators' bids) and hence is embedded within the AESC 2007 avoided electricity costs. The additional value in each year is the difference between the estimate of marginal cost to achieve a sustainability target ($60/ton CO_2) and the value of the carbon trading price embedded in the projection of wholesale electric energy prices.

Exhibit 7-13 illustrates how the additional CO_2 cost was determined. The line for the allowance price is based on the forecast of carbon allowance costs, illustrating the notion that the United States will gradually move to incorporate the climate externality into policy. The "externality" is simply the difference between the estimate of the cost of achieving a sustainability target and the anticipated allowance cost; that is, the area above the blue line (and below $60/ton) in the graph.

Exhibit 7-13. Determination of the Additional Cost of CO_2 Emissions



The carbon dioxide externality price forecast is presented above as a single simple price. This is for ease of application and because doing something more complex such as varying the shape over time or developing a distribution to represent uncertainty would go beyond the scope of this project and would stretch the available information upon

which the externality price is based. We fully acknowledge the many complexities involved in estimating a carbon price, both conceptual and practical. Some of these are listed in the Estimation of CO_2 Environmental Costs section (iv) above

With regard to environmental costs, AESC 2007 focuses on the externality value of carbon dioxide for the purpose of screening DSM programs for two main reasons. First, the environmental costs of carbon dioxide emissions are substantially greater than the costs of the other environmental impacts of electricity generation. Second, carbon dioxide is expected to be the dominant environmental impact of the marginal sources of generation in New England over the study period. Thus, the cost associated with carbon dioxide emissions dominates other values to an extent that justifies focusing exclusively on carbon dioxide.

The additional value for carbon dioxide in each year is an estimated annual sustainability target value of $60/ton minus the annual projected allowance values internalized in our model. Synapse reviewed science and policy to assess current emerging consensus on what is an appropriate sustainability target. The sustainability target value is an estimate of the cost of stabilizing carbon dioxide emissions at levels that seem likely, based on current science, to avoid more than a 2°C increase in the global average temperature. The annual allowance values are drawn from our forecast of carbon allowance prices associated with anticipated carbon regulations over the study period. The following exhibit presents the recommended values.

Exhibit 7-14. Recommended Externality Values

Year	Sustainability Target ($/ton)	Allowance Price (internalized value $/ton)	Additional Environmental Cost (Sustainability Target - Allowance Price $/ton)
2007	60	0.00	60.00
2008	60	0.00	60.00
2009	60	2.21	57.79
2010	60	2.37	57.63
2011	60	2.53	57.47
2012	60	9.46	50.54
2013	60	11.56	48.44
2014	60	13.66	46.34
2015	60	15.76	44.24
2016	60	17.86	42.14
2017	60	19.96	40.04
2018	60	22.06	37.94
2019	60	24.16	35.84
2020	60	26.27	33.73
2021	60	27.32	32.68
2022	60	28.37	31.63

The values in the right hand column of the table are, in one sense, externalities. They may be borne by citizens in the form of damages from climate change. There is also a significant chance that the "additional" CO2 costs will be borne to some degree by

electricity consumers in the form of compliance costs in electricity rates if emission regulations require greater reductions more rapidly than we have assumed.

vi. Applying CO_2 Costs in Evaluations of DSM Programs

The externality values from Exhibit 7-14 are provided in the avoided electricity cost workbooks presented in Appendix E. They are expressed as $/kWh based upon our analysis of the CO_2 emissions of the marginal generating units in each year of the study period.

At a minimum program administrators should calculate the costs and benefits of DSM programs without, and then with, these values in order to assess their incremental impact on the cost-effectiveness of programs. However, we recommend the program administrators include these values in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation. The next section explains why a DSM program could result in CO_2 emission reductions even under a cap and trade regulatory framework.

vii. Impact of DSM on Carbon Emissions Under a Cap and Trade Regulatory Framework

The Regional Greenhouse Gas Initiative is a cap and trade greenhouse gas program for power plants in the northeastern United States. Discussions to develop the program began in 2003, states signed a memorandum of understanding identifying the main elements of the program in December 2005, and in August 2006 they adopted a model rule for implementing the program. Currently nine states have decided to participate: Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Maryland passed a law in April 2006 requiring participation in RGGI. Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. Individual states are now engaged in regulatory proceedings to adopt regulations consistent with the agreement.

As currently designed, the program will:

- Stabilize CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10% reduction below current levels by 2019;
- Allocate a minimum of 25% of allowances for consumer benefit and strategic energy purposes. Allowances allocated for consumer benefit will be auctioned and the proceeds of the auction used for consumer benefit and strategic energy purposes; and
- Include certain offset provisions that increase flexibility to moderate price impacts and development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and maintain economic growth.

With carbon dioxide emissions regulated under a cap and trade system, as is assumed in this market price analysis, it is conceivable that a load reduction from a DSM program will not lead to a reduction in the amount of total system carbon dioxide emissions. The annual total system emissions for the affected facilities in the relevant region are, after all, capped. In the analysis that was documented in this report, the relevant cap and trade regulation is the Regional Greenhouse Gas Initiative (RGGI) for the period 2009 to 2012 and the assumed national cap and trade system thereafter. However, there are a number of reasons why a DSM program could result in CO_2 emission reductions, specifically:

- Reduction in load that reduces the cost (marginal or total cost) of achieving an emissions cap can result in a tightening of the cap. This is a complex interaction between the energy system and political and economic systems, and is difficult or impossible to model, but the dynamic may reasonably be assumed to exist;
- Specific provisions in RGGI provide for a tightening or loosening of the cap (via adjustments to the offset provisions that are triggered at different price levels). It is unknown at this point whether and to what extent such "automatic" adjustments might be built into the US carbon regulatory system;
- It is also possible that DSM efforts will be accompanied by specific retirements or allocations of allowances that would cause them to have an impact on the overall system level of emissions (effectively tightening the cap); and
- to the extent that the cap and trade system "leaks" because of its geographic boundaries, one would expect the benefits of a carbon emissions reduction resulting from a DSM program to similarly "leak." That is, a load reduction in New York could cause reductions in generation (and emissions) at power plants in New York, Pennsylvania, and elsewhere. Because New York is in the RGGI cap and trade system, the emissions reductions realized at New York generating units may pop up as a result of increased sales of allowances from NY to other RGGI states. But because Pennsylvania is not in the RGGI system, the emissions reductions at Pennsylvania generating units would be true reductions attributable to the DSM program.

Appendix A – Common Modeling Assumptions

Inflation Rate

Inflation increased since the AESC 2005 study, which used a rate of 2.25%. Inflation was 3.03% in 2005 and 2.90% in 2006 as shown in the exhibit below. In addition, the twenty year average (1987-2006) derived from the chained GDP deflator was 2.47%. As a result, the long-term inflation rate used in this study was 2.50%.

Exhibit A-1. GDP Price Index and Inflation Rate

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion to 2007
1985	69.72	3.04%	1.705
1986	71.27	2.22%	1.669
1987	73.20	2.72%	1.624
1988	75.71	3.42%	1.571
1989	78.57	3.78%	1.513
1990	**81.61**	**3.88%**	**1.457**
1991	84.46	3.48%	1.408
1992	86.40	2.30%	1.376
1993	88.39	2.30%	1.345
1994	90.27	2.12%	1.317
1995	92.12	2.05%	1.291
1996	93.86	1.89%	1.267
1997	95.42	1.66%	1.246
1998	96.48	1.11%	1.233
1999	97.87	1.44%	1.215
2000	**100.00**	**2.18%**	**1.189**
2001	102.40	2.40%	1.161
2002	104.19	1.75%	1.141
2003	106.41	2.13%	1.118
2004	109.43	2.84%	1.087
2005	112.74	3.03%	1.055
2006	116.01	2.90%	1.025
2007	118.91	2.50%	1.000
2008	121.89	2.50%	0.976
2009	124.93	2.50%	0.952
2010	**128.06**	**2.50%**	**0.929**
2011	131.26	2.50%	0.906
2012	134.54	2.50%	0.884
2013	137.90	2.50%	0.862
2014	141.35	2.50%	0.841
2015	144.89	2.50%	0.821
2016	148.51	2.50%	0.801
2017	152.22	2.50%	0.781
2018	156.03	2.50%	0.762
2019	159.93	2.50%	0.744
2020	**163.92**	**2.50%**	**0.725**
2021	168.02	2.50%	0.708
2022	172.22	2.50%	0.690

Note: Uses the BEA chain-type price index for GDP

Real Discount Rate

As in the AESC 2005 report, the real discount rate was based on recent rates of return for 30-year Treasury Bonds. The present nominal interest rate for those bonds is 4.77% as shown in the exhibit below. The nominal interest rate was calculated as the average yield for six 30-year US Treasury Bills. The nominal interest rate for those bonds was 4.32% in 2005, using the same methodology. Applying the updated discount rate results in a real interest rate of 2.22% for discounting (as compared to 2.03% in 2005).

Exhibit A-2. Risk-Free Interest Rate and Real Discount Rate Determination

30 Year US Treasury Bond 6.00
Maturity Date 2/15/2026

Transaction Date	Price	Yield
3/21/2007	115-07+	4.78
3/20/2007	114-07+	4.79
3/19/2007	114-11	4.81
3/16/2007	115-01	4.79
3/15/2007	115-02	4.78
3/14/2007	115-14	4.78
AVERAGE		4.788

30 Year US Treasury Bond 5.50
Maturity Date 8/15/2028

Transaction Date	Price	Yield
3/21/2007	109-07+	4.77
3/20/2007	109-06+	4.79
3/19/2007	109-10	4.8
3/16/2007	109-01	4.78
3/15/2007	109-00	4.77
3/14/2007	109-16	4.77
AVERAGE		4.780

30 Year US Treasury Bond 5.25
Maturity Date 11/15/2028

Transaction Date	Price	Yield
3/21/2007	106-05+	4.77
3/20/2007	106-07+	4.78
3/19/2007	106-10	4.8
3/16/2007	106-01	4.77
3/15/2007	106-01	4.77
3/14/2007	106-14	4.77
AVERAGE		4.777

30 Year US Treasury Bond 5.25
Maturity Date 2/15/2029

Transaction Date	Price	Yield
3/21/2007	106-06+	4.76
3/20/2007	106-06+	4.78
3/19/2007	106-10	4.79
3/16/2007	106-01	4.77
3/15/2007	106-01	4.77
3/14/2007	106-15	4.77
AVERAGE		4.773

30 Year US Treasury Bond 6.25
Maturity Date 5/15/2030

Transaction Date	Price	Yield
3/21/2007	120-07+	4.75
3/20/2007	120-07+	4.76
3/19/2007	120-12	4.78
3/16/2007	120-01	4.75
3/15/2007	120-00	4.75
3/14/2007	120-18	4.75
AVERAGE		4.757

30 Year US Treasury Bond 5.375
Maturity Date 2/15/2031

Transaction Date	Price	Yield
3/21/2007	108-07+	4.75
3/20/2007	108-06+	4.76
3/19/2007	108-11	4.78
3/16/2007	108-01	4.75
3/15/2007	108-00	4.75
3/14/2007	108-17	4.75
AVERAGE		4.757

Nominal Interest Rate	**4.77**
Real Interest Rate	**2.22**

Notes:
1) Nominal rate is the average yield for six 30-year US Treasury Bills
2) Source: http://online.wsj.com/mdc/public/page/2_3020-treasury.html?mod=topnav_2_3000
3) Assumes a 2.50% inflation rate

Escalation Rate

Section 5.a.i of the RFP asks the Contractor to develop a single real escalation rate for the post forecast period (2023 through 2037). Since the primary set of avoided costs numbers proved in the AESC report are for wholesale electricity, our analysis focused on that component.

The wholesale market price of electricity in New England in 2022 and beyond will be almost entirely determined by the marginal cost of natural gas combustion cycle generators (NG CC). The primary drivers of that cost are the prices of natural gas and of CO_2 emissions. The issue then is the escalation of those components and their relative weights in the electricity market price.

We looked first at the escalation for CO_2 prices. For this we used the Synapse mid case forecast which was used for the previous years of the AESC analysis. The real escalation rate for CO_2 prices post 2022 is 3.24% in that forecast. Regarding natural gas prices there is great uncertainty associated with reserves, production costs, and world markets and there are substantial upside risks; however, we took the fairly conservative approach of looking at the Annual Energy Outlook for 2007. In that study the real escalation rate for natural gas for electricity generation in New England is 1.01% for the period 2022 through 2030 which is the final forecast year. In the absence of any countervailing information we then assume that the same rate extends through 2037, although with continued depletion of natural gas reserves it could be higher.

We then looked first at the relative weight of these factors for NG CC prices in 2022. That analysis showed that fuel represented 73% and CO_2 22% of the marginal generation costs. Applying those factors gives a real escalation rate of 1.45% for electricity prices post 2022.

Exhibit A-3. Marginal Cost Components for a NG CC in 2022 and Calculation of a Real Price Escalation Rate

Component	Proportion	Escalation Rate
Fuel	73%	1.01%
CO_2	22%	3.24%
Other	5%	0%
Total	100%	1.45%

In comparing this with the AESC 2005 results we calculated the implied escalation rate in that study for the avoided electricity costs for the period 2023 through 2037.[134] The

[134] Avoided energy costs from "Exhibit 1 – 2005$" from "aescpoweravoidedcostexhibitsfinal2005.xls". Also in Exhibit 5-2 associated with Transmission and Distribution investment there is a Forecast Escalation Rate (nominal) of 3.07%. Since an inflation rate of 2.5% was used for that study, this implies a real escalation rate of 0.57% which is consistent with but a little less than the rate derived from the avoided electricity costs.

annual average real escalation rate from this calculation was 0.68%. This is significantly less than the current proposed escalation rate but does not incorporate CO_2 costs and reflects a more optimistic view of future energy prices.

Although there are many uncertainties associated with energy prices this far in the future, our recommendation is a real escalation rate of 1.4% for wholesale electricity prices for 2023 through 2037.

Appendix B – Forecasts of Monthly Natural Gas Prices

(Exhibits B1 – B7 are in 2007$; Exhibits B8 – B14 are in Nominal$.)

Exhibit B-1. Monthly Henry Hub Natural Gas Price Forecast 2007-2022 (2007$/MMBtu)

	Monthly Adj Factor	1.1159874	1.1178952	1.0909087	0.9272738	0.9144141	0.924639	0.9358622	0.9450845	0.9538974	0.9687786	1.0250697	1.080189319
Year	HH Ann Avg Price	1	2	3	4	5	6	7	8	9	10	11	12
2007	7.71	5.84	6.93	7.55	6.96	7.11	7.77	7.92	8.02	8.06	8.15	8.81	9.46
2008	8.65	9.78	9.74	9.49	8.15	8.00	8.06	8.12	8.17	8.20	8.27	8.71	9.15
2009	8.16	9.38	9.35	9.09	7.63	7.49	7.54	7.61	7.66	7.69	7.76	8.17	8.57
2010	7.65	8.76	8.74	8.48	7.15	7.02	7.07	7.13	7.17	7.20	7.28	7.67	8.06
2011	7.20	8.24	8.21	7.98	6.73	6.60	6.66	6.72	6.75	6.78	6.86	7.24	7.62
2012	6.86	7.80	7.78	7.56	6.43	6.31	6.37	6.42	6.45	6.48	6.56	6.91	7.26
2013	6.24	6.97	6.98	6.81	5.79	5.71	5.77	5.84	5.90	5.95	6.05	6.40	6.74
2014	6.30	7.03	7.04	6.87	5.84	5.76	5.82	5.90	5.95	6.01	6.10	6.46	6.80
2015	6.25	6.98	6.99	6.82	5.80	5.72	5.78	5.85	5.91	5.97	6.06	6.41	6.76
2016	6.39	7.13	7.14	6.97	5.92	5.84	5.91	5.98	6.04	6.09	6.19	6.55	6.90
2017	6.64	7.41	7.42	7.24	6.15	6.07	6.14	6.21	6.27	6.33	6.43	6.80	7.17
2018	6.56	7.32	7.33	7.16	6.08	6.00	6.07	6.14	6.20	6.26	6.36	6.72	7.09
2019	6.52	7.27	7.28	7.11	6.04	5.96	6.03	6.10	6.16	6.22	6.31	6.68	7.04
2020	6.63	7.40	7.42	7.24	6.15	6.07	6.13	6.21	6.27	6.33	6.43	6.80	7.17
2021	6.73	7.52	7.53	7.35	6.25	6.16	6.23	6.30	6.37	6.42	6.52	6.90	7.28
2022	6.98	7.79	7.81	7.62	6.48	6.39	6.46	6.54	6.60	6.66	6.77	7.16	7.54

Notes:
1/07-5/07 are actual prices
6/07-12/12 are forecasted prices from NYMEX as of May 2, 2007
2007-2012 HH Annual Average Prices are straight averages across the months of each year
2013-2022 HH Annual Average Prices are forecasted
Prices for 1/13-12/22 are calculated by multiplying the HH Annual Average Price by the Monthly Adjustment Factor

Exhibit B-2. Monthly Regional Natural Gas Price Forecast 2007-2022 (2007$/MMBtu) – ALG

Year	Monthly Prem Factor / Ann Avg Price	1.3659648 / 1	1.3343223 / 2	1.1408184 / 3	1.0927116 / 4	1.0931588 / 5	1.0932223 / 6	1.0987813 / 7	1.0849414 / 8	1.073207 / 9	1.0915255 / 10	1.1243434 / 11	1.204758479 / 12
2007	8.82	7.69	9.73	8.30	7.61	7.77	8.49	8.70	8.70	8.65	8.90	9.90	11.40
2008	10.01	13.35	13.00	10.82	8.90	8.75	8.81	8.92	8.87	8.80	9.03	9.80	11.02
2009	9.44	12.81	12.47	10.37	8.34	8.19	8.25	8.36	8.31	8.25	8.47	9.19	10.33
2010	8.85	11.97	11.66	9.68	7.82	7.67	7.73	7.84	7.78	7.73	7.95	8.63	9.71
2011	8.33	11.25	10.96	9.10	7.36	7.22	7.28	7.38	7.33	7.28	7.49	8.14	9.18
2012	7.94	10.65	10.38	8.62	7.03	6.90	6.96	7.05	7.00	6.96	7.16	7.77	8.75
2013	7.22	9.52	9.31	7.77	6.32	6.24	6.31	6.42	6.40	6.39	6.60	7.19	8.12
2014	7.28	9.60	9.40	7.84	6.38	6.30	6.37	6.48	6.46	6.45	6.66	7.26	8.20
2015	7.23	9.53	9.33	7.78	6.34	6.25	6.32	6.43	6.41	6.40	6.61	7.21	8.14
2016	7.39	9.74	9.53	7.95	6.47	6.39	6.46	6.57	6.55	6.54	6.76	7.36	8.32
2017	7.67	10.12	9.90	8.26	6.72	6.63	6.71	6.82	6.80	6.79	7.02	7.65	8.64
2018	7.58	10.00	9.79	8.16	6.65	6.56	6.63	6.75	6.73	6.72	6.94	7.56	8.54
2019	7.53	9.93	9.72	8.11	6.60	6.51	6.59	6.70	6.68	6.67	6.89	7.51	8.48
2020	7.67	10.11	9.90	8.26	6.72	6.63	6.71	6.82	6.80	6.79	7.02	7.65	8.63
2021	7.79	10.27	10.05	8.38	6.82	6.73	6.81	6.93	6.91	6.89	7.12	7.76	8.76
2022	8.07	10.65	10.42	8.69	7.08	6.98	7.06	7.18	7.16	7.15	7.38	8.05	9.09

Notes:
Prices for all months are calculated by multiplying the Henry Hub Monthly Price by the Monthly Factor for Algonquin City Gate
2007-2022 Annual Average Prices are straight averages across the months of each year

Exhibit B-3. Monthly Regional Natural Gas Price Forecast 2007-2022 (2007$/MMBtu) – TGP Z6

Year	Monthly Prem Factor / Ann Avg Price	1.2735839 / 1	1.2766407 / 2	1.1333628 / 3	1.0860551 / 4	1.0837252 / 5	1.0814196 / 6	1.0849595 / 7	1.0767206 / 8	1.0662243 / 9	1.0786931 / 10	1.1111352 / 11	1.177818291 / 12
2007	8.69	7.28	9.55	8.23	7.56	7.70	8.40	8.59	8.63	8.59	8.79	9.79	11.15
2008	9.80	12.45	12.44	10.75	8.85	8.67	8.71	8.81	8.80	8.74	8.92	9.68	10.77
2009	9.25	11.95	11.93	10.30	8.29	8.12	8.16	8.25	8.24	8.20	8.37	9.08	10.10
2010	8.66	11.16	11.15	9.61	7.77	7.61	7.65	7.74	7.72	7.68	7.86	8.53	9.49
2011	8.16	10.49	10.48	9.04	7.31	7.16	7.20	7.29	7.27	7.23	7.40	8.04	8.97
2012	7.77	9.93	9.93	8.57	6.99	6.84	6.88	6.96	6.95	6.91	7.08	7.68	8.55
2013	7.07	8.87	8.91	7.72	6.29	6.19	6.24	6.34	6.35	6.35	6.52	7.11	7.94
2014	7.13	8.95	8.99	7.79	6.34	6.24	6.30	6.40	6.41	6.41	6.58	7.17	8.01
2015	7.08	8.89	8.93	7.73	6.30	6.20	6.25	6.35	6.36	6.36	6.54	7.12	7.96
2016	7.24	9.08	9.12	7.90	6.43	6.33	6.39	6.49	6.50	6.50	6.68	7.28	8.13
2017	7.51	9.43	9.47	8.20	6.68	6.58	6.64	6.74	6.75	6.75	6.93	7.56	8.44
2018	7.43	9.32	9.36	8.11	6.61	6.50	6.56	6.66	6.68	6.67	6.86	7.47	8.35
2019	7.38	9.26	9.30	8.06	6.56	6.46	6.52	6.62	6.63	6.63	6.81	7.42	8.29
2020	7.51	9.43	9.47	8.20	6.68	6.57	6.63	6.74	6.75	6.75	6.93	7.56	8.44
2021	7.63	9.57	9.61	8.33	6.78	6.67	6.73	6.84	6.85	6.85	7.04	7.67	8.57
2022	7.91	9.93	9.97	8.63	7.03	6.92	6.98	7.09	7.11	7.10	7.30	7.95	8.88

Notes:
Prices for all months are calculated by multiplying the Henry Hub Monthly Price by the Monthly Factor for Tennessee Zone 6
2007-2022 Annual Average Prices are straight averages across the months of each year

Exhibit B-4. Monthly New England Natural Gas for Electric Generation Price Forecast 2007-2022 (2007$/MMBtu)

Year	Monthly Prem Factor / Ann Avg Price	1.365965 / 1	1.334322 / 2	1.140818 / 3	1.092712 / 4	1.093159 / 5	1.093222 / 6	1.098781 / 7	1.084941 / 8	1.073207 / 9	1.091526 / 10	1.124343 / 11	1.204758 / 12
2007	8.82	7.49	9.64	8.27	7.65	7.80	8.52	8.72	8.74	8.69	8.91	9.92	11.34
2008	9.97	12.97	12.79	10.86	8.95	8.78	8.83	8.94	8.90	8.84	9.05	9.81	10.97
2009	9.42	12.45	12.27	10.40	8.38	8.22	8.27	8.37	8.34	8.29	8.49	9.20	10.28
2010	8.83	11.64	11.47	9.72	7.86	7.71	7.76	7.86	7.82	7.78	7.97	8.65	9.67
2011	8.31	10.94	10.79	9.14	7.40	7.26	7.31	7.40	7.37	7.32	7.51	8.16	9.15
2012	7.92	10.36	10.22	8.66	7.08	6.94	6.99	7.08	7.04	7.01	7.19	7.80	8.72
2013	7.21	9.26	9.18	7.81	6.38	6.28	6.35	6.45	6.45	6.44	6.63	7.22	8.10
2014	7.28	9.35	9.26	7.88	6.43	6.34	6.40	6.51	6.50	6.50	6.69	7.29	8.18
2015	7.23	9.28	9.20	7.83	6.39	6.29	6.36	6.46	6.46	6.45	6.64	7.24	8.12
2016	7.38	9.48	9.39	8.00	6.52	6.43	6.49	6.60	6.60	6.59	6.79	7.39	8.29
2017	7.66	9.84	9.75	8.30	6.77	6.67	6.74	6.85	6.85	6.84	7.05	7.67	8.61
2018	7.58	9.73	9.64	8.21	6.70	6.60	6.67	6.77	6.77	6.76	6.97	7.59	8.51
2019	7.53	9.67	9.58	8.15	6.65	6.56	6.62	6.73	6.73	6.72	6.92	7.54	8.46
2020	7.66	9.84	9.75	8.30	6.77	6.67	6.74	6.85	6.85	6.84	7.04	7.67	8.61
2021	7.78	9.99	9.90	8.42	6.87	6.77	6.84	6.95	6.95	6.94	7.15	7.79	8.74
2022	8.06	10.36	10.26	8.73	7.12	7.02	7.09	7.21	7.20	7.20	7.41	8.07	9.06

Notes:
Prices are based on the average of the Algonquin City Gate & Tennessee Zone 6 prices along with a transportation markup.
NG markup for electric generation 0.07 $/MMBtu

Exhibit B-5. Avoided Cost of Gas Delivered to Retail Customers in Southern New England by End Use (Gas Delivered via Texas Eastern and Algonquin Gas Pipelines) in 2007$/Dekatherm

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	RETAIL
Year	3-mon.	5-mon.	annual	6-mon.	annual	5-mon.	6-mon.	5-mon.
2007	13.42	13.19	11.96	12.82	9.92	11.16	10.79	12.04
2008	14.51	14.27	12.96	13.88	10.93	12.23	11.84	13.12
2009	13.94	13.70	12.44	13.32	10.40	11.67	11.29	12.56
2010	13.34	13.11	11.88	12.74	9.85	11.08	10.71	11.97
2011	12.82	12.60	11.40	12.24	9.37	10.56	10.21	11.45
2012	12.43	12.21	11.04	11.86	9.01	10.17	9.83	11.06
2013	11.71	11.50	10.38	11.16	8.34	9.46	9.13	10.35
2014	11.78	11.56	10.44	11.23	8.41	9.53	9.20	10.42
2015	11.73	11.51	10.39	11.18	8.36	9.48	9.14	10.37
2016	11.89	11.67	10.53	11.33	8.50	9.63	9.30	10.52
2017	12.17	11.95	10.80	11.61	8.77	9.92	9.57	10.81
2018	12.08	11.86	10.72	11.52	8.69	9.83	9.49	10.72
2019	12.03	11.81	10.67	11.47	8.64	9.78	9.44	10.67
2020	12.17	11.95	10.80	11.61	8.76	9.91	9.57	10.80
2021	12.29	12.06	10.91	11.72	8.87	10.03	9.69	10.92
2022	12.57	12.35	11.17	12.00	9.14	10.32	9.97	11.20
2023	12.70	12.47	11.28	12.12	9.23	10.42	10.06	11.32
2024	12.83	12.60	11.40	12.24	9.32	10.52	10.17	11.43
2025	12.95	12.72	11.51	12.36	9.42	10.63	10.27	11.54
2026	13.08	12.85	11.63	12.49	9.51	10.73	10.37	11.66
2027	13.21	12.98	11.74	12.61	9.61	10.84	10.47	11.78
2028	13.35	13.11	11.86	12.74	9.70	10.95	10.58	11.89
2029	13.48	13.24	11.98	12.86	9.80	11.06	10.68	12.01
2030	13.61	13.37	12.10	12.99	9.90	11.17	10.79	12.13
2031	13.75	13.51	12.22	13.12	10.00	11.28	10.90	12.25
2032	13.89	13.64	12.34	13.25	10.10	11.39	11.01	12.38
2033	14.03	13.78	12.46	13.39	10.20	11.51	11.12	12.50
2034	14.17	13.91	12.59	13.52	10.30	11.62	11.23	12.63
2035	14.31	14.05	12.72	13.65	10.40	11.74	11.34	12.75
2036	14.45	14.19	12.84	13.79	10.51	11.86	11.45	12.88
2037	14.60	14.34	12.97	13.93	10.61	11.98	11.57	13.01
2038	14.74	14.48	13.10	14.07	10.72	12.10	11.68	13.14
2039	14.89	14.62	13.23	14.21	10.82	12.22	11.80	13.27
2040	15.04	14.77	13.36	14.35	10.93	12.34	11.92	13.40
Levelized								
(2008-2040)	13.098	12.864	11.639	12.499	9.519	10.744	10.379	11.671
(2009-2040)	13.036	12.803	11.580	12.439	9.456	10.679	10.315	11.608
5 years (2008-12)	13.430	13.199	11.967	12.831	9.934	11.166	10.798	12.055
10 years (2008-17)	12.684	12.459	11.275	12.106	9.242	10.426	10.073	11.315
15 years (2008-22)	12.547	12.322	11.148	11.973	9.115	10.290	9.940	11.179

Real discount rate: 2.2165%

Exhibit B-6. Avoided Cost of Gas Delivered to Retail Customers in Northern and Central New England by End Use (Gas Delivered via Tennessee Gas Pipeline) in 2007$/Dekatherm

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
Year	3-mon.	5-mon.	annual	6-mon.	annual	5-mon.	6-mon.	5-mon.
2007	12.88	12.71	11.65	12.39	10.58	11.63	11.32	12.12
2008	13.95	13.77	12.65	13.43	11.57	12.69	12.35	13.18
2009	13.39	13.21	12.13	12.88	11.05	12.14	11.81	12.63
2010	12.81	12.63	11.58	12.31	10.51	11.55	11.24	12.04
2011	12.30	12.12	11.11	11.82	10.03	11.05	10.74	11.54
2012	11.92	11.74	10.75	11.44	9.68	10.67	10.37	11.16
2013	11.21	11.04	10.10	10.76	9.02	9.97	9.68	10.46
2014	11.28	11.11	10.16	10.82	9.08	10.03	9.75	10.52
2015	11.23	11.06	10.11	10.77	9.03	9.98	9.70	10.47
2016	11.38	11.21	10.25	10.92	9.18	10.13	9.85	10.62
2017	11.66	11.49	10.51	11.20	9.44	10.41	10.12	10.90
2018	11.57	11.40	10.43	11.11	9.36	10.33	10.04	10.82
2019	11.52	11.35	10.39	11.06	9.31	10.28	9.99	10.77
2020	11.66	11.49	10.51	11.19	9.44	10.41	10.12	10.90
2021	11.77	11.60	10.62	11.30	9.54	10.52	10.23	11.01
2022	12.05	11.88	10.88	11.58	9.80	10.81	10.51	11.30
2023	12.17	12.00	10.99	11.70	9.90	10.91	10.61	11.41
2024	12.30	12.12	11.10	11.81	10.00	11.02	10.72	11.52
2025	12.42	12.24	11.21	11.93	10.10	11.13	10.82	11.64
2026	12.54	12.36	11.32	12.05	10.20	11.24	10.93	11.75
2027	12.67	12.49	11.43	12.17	10.31	11.36	11.04	11.87
2028	12.80	12.61	11.55	12.29	10.41	11.47	11.15	11.99
2029	12.92	12.74	11.66	12.42	10.51	11.58	11.26	12.11
2030	13.05	12.86	11.78	12.54	10.62	11.70	11.38	12.23
2031	13.18	12.99	11.90	12.67	10.72	11.82	11.49	12.35
2032	13.32	13.12	12.02	12.79	10.83	11.94	11.60	12.48
2033	13.45	13.25	12.14	12.92	10.94	12.05	11.72	12.60
2034	13.58	13.39	12.26	13.05	11.05	12.18	11.84	12.73
2035	13.72	13.52	12.38	13.18	11.16	12.30	11.96	12.86
2036	13.86	13.66	12.51	13.31	11.27	12.42	12.08	12.98
2037	13.99	13.79	12.63	13.44	11.38	12.54	12.20	13.11
2038	14.13	13.93	12.76	13.58	11.50	12.67	12.32	13.24
2039	14.28	14.07	12.89	13.71	11.61	12.80	12.44	13.38
2040	14.42	14.21	13.01	13.85	11.73	12.92	12.57	13.51
Levelized								
(2008-2040)	12.558	12.376	11.334	12.064	10.213	11.255	10.943	11.766
(2009-2040)	12.496	12.315	11.276	12.004	10.153	11.192	10.881	11.704
5 years (2008-12)	12.895	12.717	11.663	12.400	10.588	11.642	11.325	12.132
10 years (2008-17)	12.163	11.989	10.982	11.687	9.907	10.914	10.612	11.404
15 years (2008-22)	12.029	11.855	10.856	11.555	9.781	10.780	10.480	11.270

Real discount rate: 2.2165%

Exhibit B-7. Avoided Cost of Gas Delivered to Retail Customers in Vermont by End Use (Gas Delivered via TransCanada Pipeline) in 2007$/Dekatherm

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
Year	3-mon.	5-mon.	annual	6-mon.	annual	5-mon.	6-mon.	5-mon.
2007	12.14	11.90	10.66	11.53	8.65	9.89	9.52	10.65
2008	13.09	12.84	11.54	12.45	9.53	10.83	10.44	11.58
2009	12.59	12.35	11.08	11.97	9.07	10.34	9.96	11.09
2010	12.07	11.83	10.60	11.47	8.59	9.82	9.46	10.58
2011	11.62	11.38	10.18	11.03	8.17	9.38	9.02	10.13
2012	11.28	11.05	9.87	10.70	7.86	9.04	8.69	9.79
2013	10.65	10.43	9.29	10.09	7.28	8.42	8.08	9.17
2014	10.71	10.49	9.34	10.15	7.33	8.48	8.14	9.23
2015	10.67	10.44	9.30	10.10	7.29	8.43	8.10	9.19
2016	10.80	10.58	9.43	10.24	7.42	8.57	8.23	9.32
2017	11.05	10.82	9.66	10.48	7.65	8.81	8.47	9.57
2018	10.98	10.75	9.59	10.40	7.58	8.74	8.40	9.49
2019	10.93	10.70	9.55	10.36	7.54	8.69	8.35	9.45
2020	11.05	10.82	9.66	10.48	7.65	8.81	8.47	9.57
2021	11.15	10.92	9.75	10.57	7.74	8.91	8.57	9.67
2022	11.40	11.17	9.98	10.82	7.97	9.16	8.81	9.92
2023	11.52	11.28	10.08	10.93	8.05	9.25	8.90	10.01
2024	11.63	11.39	10.18	11.03	8.13	9.35	8.99	10.12
2025	11.75	11.51	10.28	11.15	8.21	9.44	9.08	10.22
2026	11.87	11.62	10.39	11.26	8.30	9.53	9.17	10.32
2027	11.98	11.74	10.49	11.37	8.38	9.63	9.26	10.42
2028	12.10	11.86	10.59	11.48	8.46	9.72	9.35	10.53
2029	12.23	11.97	10.70	11.60	8.55	9.82	9.44	10.63
2030	12.35	12.09	10.81	11.71	8.63	9.92	9.54	10.74
2031	12.47	12.22	10.92	11.83	8.72	10.02	9.63	10.84
2032	12.60	12.34	11.02	11.95	8.81	10.12	9.73	10.95
2033	12.72	12.46	11.14	12.07	8.89	10.22	9.83	11.06
2034	12.85	12.59	11.25	12.19	8.98	10.32	9.93	11.17
2035	12.98	12.71	11.36	12.31	9.07	10.43	10.03	11.29
2036	13.11	12.84	11.47	12.43	9.16	10.53	10.13	11.40
2037	13.24	12.97	11.59	12.56	9.26	10.64	10.23	11.51
2038	13.37	13.10	11.70	12.68	9.35	10.74	10.33	11.63
2039	13.50	13.23	11.82	12.81	9.44	10.85	10.43	11.74
2040	13.64	13.36	11.94	12.94	9.54	10.96	10.54	11.86
Levelized								
(2008-2040)	11.880	11.636	10.398	11.270	8.303	9.542	9.175	10.329
(2009-2040)	11.827	11.584	10.348	11.218	8.249	9.485	9.119	10.274
5 years (2008-12)	12.151	11.909	10.671	11.542	8.663	9.901	9.534	10.656
10 years (2008-17)	11.500	11.265	10.070	10.911	8.062	9.257	8.903	10.012
15 years (2008-22)	11.380	11.147	9.960	10.795	7.951	9.138	8.787	9.893

Real discount rate: 2.2165%

Exhibit B-8. Monthly Henry Hub Natural Gas Price Forecast 2007-2022 (Nominal$/MMBtu)

Year	Monthly Adj Factor / HH Ann Avg Nominal Price	1.1159874 1	1.1178952 2	1.0909087 3	0.9272738 4	0.9144141 5	0.924639 6	0.9358622 7	0.9450845 8	0.9538974 9	0.9687786 10	1.0250697 11	1.080189319 12
2007	7.71	5.84	6.93	7.55	6.96	7.11	7.77	7.92	8.02	8.06	8.15	8.81	9.46
2008	8.87	10.02	9.99	9.72	8.35	8.20	8.26	8.33	8.38	8.40	8.48	8.93	9.38
2009	8.57	9.86	9.82	9.55	8.02	7.87	7.93	7.99	8.04	8.08	8.16	8.59	9.01
2010	8.23	9.44	9.41	9.14	7.70	7.56	7.62	7.68	7.73	7.76	7.84	8.26	8.68
2011	7.95	9.09	9.06	8.80	7.43	7.29	7.35	7.41	7.45	7.49	7.57	7.99	8.41
2012	7.76	8.82	8.80	8.55	7.28	7.14	7.20	7.26	7.30	7.34	7.42	7.82	8.21
2013	7.24	8.08	8.09	7.90	6.71	6.62	6.69	6.77	6.84	6.90	7.01	7.42	7.82
2014	7.49	8.36	8.37	8.17	6.94	6.85	6.92	7.01	7.08	7.14	7.25	7.68	8.09
2015	7.62	8.50	8.52	8.31	7.07	6.97	7.05	7.13	7.20	7.27	7.38	7.81	8.23
2016	7.98	8.91	8.92	8.71	7.40	7.30	7.38	7.47	7.54	7.61	7.73	8.18	8.62
2017	8.49	9.48	9.50	9.27	7.88	7.77	7.85	7.95	8.03	8.10	8.23	8.71	9.18
2018	8.61	9.61	9.62	9.39	7.98	7.87	7.96	8.06	8.14	8.21	8.34	8.82	9.30
2019	8.76	9.78	9.80	9.56	8.13	8.01	8.10	8.20	8.28	8.36	8.49	8.98	9.47
2020	9.15	10.21	10.22	9.98	8.48	8.36	8.46	8.56	8.64	8.72	8.86	9.37	9.88
2021	9.52	10.62	10.64	10.38	8.82	8.70	8.80	8.91	8.99	9.08	9.22	9.76	10.28
2022	10.11	11.29	11.31	11.03	9.38	9.25	9.35	9.47	9.56	9.65	9.80	10.37	10.93

Notes:
1/07-5/07 are actual prices
6/07-12/12 are forecasted prices from NYMEX as of May 2, 2007
2007-2012 HH Annual Average Prices are straight averages across the months of each year
2013-2022 HH Annual Average Prices are forecasted
Prices for 1/13-12/22 are calculated by multiplying the HH Annual Average Price by the Monthly Adjustment Factor

Exhibit B-9. Monthly Regional Natural Gas Price Forecast 2007-2022 (Nominal$/MMBtu) – ALG

Year	Monthly Prem Factor / Ann Avg Nominal Price	1.3659648 / 1	1.3343223 / 2	1.1408184 / 3	1.0927116 / 4	1.0931588 / 5	1.0932223 / 6	1.0987813 / 7	1.0849414 / 8	1.073207 / 9	1.0915255 / 10	1.1243434 / 11	1.204758479 / 12
2007	8.82	7.69	9.73	8.30	7.61	7.77	8.49	8.70	8.70	8.65	8.90	9.90	11.40
2008	10.51	14.03	13.66	11.37	9.35	9.19	9.25	9.38	9.32	9.24	9.49	10.29	11.58
2009	10.42	14.14	13.77	11.44	9.20	9.04	9.10	9.22	9.17	9.11	9.35	10.14	11.40
2010	10.26	13.88	13.52	11.22	9.06	8.90	8.97	9.09	9.03	8.97	9.22	10.01	11.26
2011	10.15	13.71	13.35	11.09	8.96	8.80	8.87	8.99	8.93	8.87	9.12	9.92	11.18
2012	10.16	13.64	13.29	11.04	9.00	8.83	8.91	9.03	8.96	8.91	9.17	9.95	11.20
2013	9.70	12.80	12.52	10.45	8.51	8.39	8.49	8.63	8.61	8.59	8.88	9.68	10.92
2014	10.29	13.57	13.28	11.08	9.02	8.90	9.00	9.15	9.13	9.11	9.41	10.26	11.58
2015	10.73	14.15	13.85	11.55	9.41	9.28	9.39	9.55	9.52	9.50	9.82	10.70	12.08
2016	11.52	15.19	14.87	12.40	10.10	9.96	10.07	10.25	10.22	10.20	10.54	11.49	12.97
2017	12.57	16.58	16.22	13.53	11.02	10.87	10.99	11.18	11.15	11.13	11.50	12.53	14.15
2018	13.06	17.22	16.85	14.06	11.44	11.29	11.42	11.61	11.58	11.56	11.94	13.02	14.70
2019	13.63	17.97	17.58	14.67	11.94	11.78	11.91	12.12	12.09	12.07	12.46	13.58	15.34
2020	14.57	19.22	18.80	15.69	12.77	12.60	12.74	12.96	12.93	12.91	13.33	14.53	16.41
2021	15.55	20.50	20.06	16.73	13.62	13.44	13.59	13.83	13.79	13.77	14.22	15.50	17.50
2022	16.93	22.33	21.85	18.23	14.84	14.64	14.81	15.06	15.02	15.00	15.49	16.88	19.06

Notes:
Prices for all months are calculated by multiplying the Henry Hub Monthly Price by the Monthly Factor for Algonquin City Gate
2007-2022 Annual Average Prices are straight averages across the months of each year

Exhibit B-10. Monthly Regional Natural Gas Price Forecast 2007-2022 (Nominal$/MMBtu) – TGP Z6

Year	Monthly Prem Factor / Ann Avg Nominal Price	1.2735839 1	1.2766407 2	1.1333628 3	1.0860551 4	1.0837252 5	1.0814196 6	1.0849595 7	1.0767206 8	1.0662243 9	1.0786931 10	1.1111352 11	1.177818291 12
2007	8.69	7.28	9.55	8.23	7.56	7.70	8.40	8.59	8.63	8.59	8.79	9.79	11.15
2008	10.30	13.08	13.07	11.29	9.30	9.11	9.15	9.26	9.25	9.18	9.37	10.17	11.32
2009	10.21	13.19	13.17	11.37	9.15	8.96	9.01	9.11	9.10	9.05	9.24	10.02	11.15
2010	10.05	12.94	12.93	11.15	9.01	8.82	8.87	8.98	8.96	8.91	9.11	9.89	11.01
2011	9.94	12.78	12.77	11.01	8.91	8.72	8.77	8.88	8.86	8.81	9.01	9.80	10.93
2012	9.95	12.71	12.71	10.96	8.94	8.76	8.81	8.91	8.89	8.85	9.06	9.83	10.95
2013	9.51	11.93	11.98	10.38	8.45	8.32	8.39	8.52	8.54	8.54	8.77	9.56	10.68
2014	10.08	12.65	12.70	11.01	8.96	8.82	8.90	9.04	9.06	9.05	9.30	10.14	11.32
2015	10.51	13.20	13.25	11.48	9.35	9.20	9.28	9.43	9.45	9.44	9.70	10.57	11.81
2016	11.29	14.16	14.22	12.32	10.04	9.88	9.97	10.12	10.14	10.14	10.41	11.35	12.68
2017	12.31	15.45	15.52	13.44	10.95	10.78	10.87	11.04	11.06	11.06	11.36	12.38	13.83
2018	12.79	16.05	16.12	13.96	11.37	11.19	11.29	11.47	11.49	11.49	11.80	12.86	14.37
2019	13.35	16.75	16.82	14.57	11.87	11.68	11.79	11.97	11.99	11.99	12.32	13.42	15.00
2020	14.28	17.92	17.99	15.59	12.70	12.49	12.61	12.80	12.83	12.82	13.17	14.36	16.04
2021	15.23	19.11	19.19	16.63	13.54	13.33	13.45	13.65	13.68	13.68	14.05	15.32	17.11
2022	16.59	20.82	20.91	18.11	14.75	14.52	14.65	14.87	14.91	14.90	15.31	16.68	18.64

Notes:
Prices for all months are calculated by multiplying the Henry Hub Monthly Price by the Monthly Factor for Tennessee Zone 6
2007-2022 Annual Average Prices are straight averages across the months of each year

Exhibit B-11. Monthly New England Natural Gas for Electric Generation Price Forecast 2007-2022 (Nominal$/MMBtu)

Year	Monthly Prem Factor / Nominal Ann Avg Price	1.365965 1	1.334322 2	1.140818 3	1.092712 4	1.093159 5	1.093222 6	1.098781 7	1.084941 8	1.073207 9	1.091526 10	1.124343 11	1.204758 12
2007	8.82	7.49	9.64	8.27	7.65	7.80	8.52	8.72	8.74	8.69	8.91	9.92	11.34
2008	10.22	13.30	13.11	11.13	9.17	9.00	9.05	9.16	9.13	9.06	9.27	10.05	11.24
2009	9.89	13.08	12.89	10.93	8.81	8.64	8.69	8.80	8.77	8.71	8.92	9.67	10.80
2010	9.50	12.53	12.36	10.46	8.47	8.30	8.36	8.46	8.43	8.37	8.58	9.31	10.42
2011	9.18	12.08	11.91	10.09	8.17	8.01	8.07	8.17	8.13	8.08	8.29	9.01	10.09
2012	8.97	11.72	11.57	9.80	8.01	7.85	7.91	8.01	7.97	7.93	8.14	8.82	9.86
2013	8.36	10.74	10.65	9.06	7.39	7.29	7.36	7.48	7.48	7.47	7.69	8.38	9.40
2014	8.65	11.11	11.01	9.37	7.65	7.54	7.61	7.73	7.73	7.72	7.95	8.66	9.72
2015	8.80	11.31	11.21	9.54	7.78	7.67	7.75	7.87	7.87	7.86	8.10	8.82	9.89
2016	9.22	11.84	11.73	9.99	8.15	8.03	8.11	8.24	8.24	8.23	8.48	9.23	10.36
2017	9.81	12.60	12.49	10.63	8.67	8.54	8.63	8.77	8.77	8.76	9.02	9.82	11.02
2018	9.94	12.77	12.65	10.77	8.79	8.66	8.75	8.89	8.88	8.88	9.14	9.95	11.17
2019	10.12	13.00	12.88	10.97	8.95	8.82	8.90	9.05	9.05	9.04	9.31	10.14	11.37
2020	10.56	13.57	13.44	11.44	9.33	9.20	9.29	9.44	9.44	9.43	9.71	10.57	11.86
2021	10.99	14.12	13.99	11.90	9.71	9.57	9.67	9.82	9.82	9.81	10.10	11.00	12.34
2022	11.67	15.00	14.86	12.65	10.32	10.17	10.27	10.44	10.43	10.42	10.73	11.69	13.12

Notes:
Prices are based on the average of the Algonquin City Gate & Tennessee Zone 6 prices along with a transportation markup.
NG markup for electric generation 0.07 $/MMBtu

Exhibit B-12. Avoided Cost of Gas Delivered to Retail Customers in Southern New England by End Use (Gas Delivered via Texas Eastern and Algonquin Gas Pipelines) in Nominal$/Dekatherm

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
Year	3-mon.	5-mon.	annual	6-mon.	annual	5-mon.	6-mon.	5-mon.
2007	13.42	13.19	11.96	12.82	9.92	11.16	10.79	12.04
2008	14.87	14.62	13.29	14.22	11.20	12.54	12.14	13.45
2009	14.64	14.39	13.07	14.00	10.93	12.26	11.86	13.19
2010	14.37	14.12	12.80	13.72	10.61	11.93	11.53	12.89
2011	14.15	13.90	12.59	13.51	10.34	11.66	11.27	12.64
2012	14.06	13.81	12.49	13.42	10.19	11.51	11.12	12.52
2013	13.59	13.33	12.03	12.95	9.68	10.98	10.59	12.01
2014	14.00	13.74	12.41	13.35	9.99	11.33	10.93	12.39
2015	14.29	14.02	12.66	13.62	10.18	11.55	11.14	12.63
2016	14.84	14.57	13.16	14.15	10.62	12.03	11.61	13.14
2017	15.58	15.30	13.82	14.86	11.22	12.69	12.26	13.83
2018	15.85	15.56	14.06	15.12	11.40	12.90	12.45	14.06
2019	16.18	15.89	14.35	15.43	11.62	13.15	12.70	14.35
2020	16.77	16.47	14.88	16.00	12.08	13.67	13.20	14.89
2021	17.36	17.04	15.41	16.56	12.54	14.17	13.69	15.43
2022	18.21	17.88	16.18	17.38	13.24	14.94	14.43	16.23
2023	18.85	18.51	16.75	17.99	13.70	15.47	14.94	16.80
2024	19.52	19.17	17.34	18.62	14.19	16.01	15.47	17.39
2025	20.20	19.84	17.95	19.28	14.69	16.58	16.01	18.01
2026	20.92	20.54	18.59	19.96	15.20	17.16	16.58	18.64
2027	21.65	21.27	19.24	20.66	15.74	17.77	17.16	19.30
2028	22.42	22.02	19.92	21.39	16.29	18.39	17.77	19.98
2029	23.21	22.79	20.62	22.15	16.87	19.04	18.39	20.68
2030	24.02	23.60	21.35	22.93	17.46	19.71	19.04	21.41
2031	24.87	24.43	22.10	23.73	18.08	20.41	19.71	22.16
2032	25.75	25.29	22.88	24.57	18.72	21.12	20.41	22.95
2033	26.66	26.18	23.69	25.44	19.38	21.87	21.13	23.75
2034	27.60	27.10	24.52	26.33	20.06	22.64	21.87	24.59
2035	28.57	28.06	25.39	27.26	20.77	23.44	22.64	25.46
2036	29.57	29.05	26.28	28.22	21.50	24.26	23.44	26.36
2037	30.62	30.07	27.21	29.22	22.26	25.12	24.27	27.29
2038	31.70	31.13	28.17	30.25	23.04	26.01	25.12	28.25
2039	32.81	32.23	29.16	31.31	23.85	26.92	26.01	29.24
2040	33.97	33.36	30.19	32.42	24.69	27.87	26.93	30.27
Levelized								
(2008-2040)	18.490	18.160	16.429	17.644	13.437	15.167	14.652	16.476
(2009-2040)	18.713	18.377	16.623	17.855	13.574	15.329	14.806	16.662
5 years (2008-12)	14.438	14.189	12.865	13.794	10.680	12.004	11.609	12.960
10 years (2008-17)	14.428	14.172	12.826	13.771	10.513	11.859	11.458	12.871
15 years (2008-22)	15.049	14.779	13.371	14.360	10.933	12.341	11.922	13.408

Nominal discount rate: 4.7755%

Exhibit B-13. Avoided Cost of Gas Delivered to Retail Customers in Northern and Central New England by End Use (Gas Delivered via Tennessee Gas Pipeline) in Nominal$/Dekatherm

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
Year	3-mon.	5-mon.	annual	6-mon.	annual	5-mon.	6-mon.	5-mon.
2007	12.88	12.71	11.65	12.39	10.58	11.63	11.32	12.12
2008	14.30	14.11	12.96	13.76	11.86	13.01	12.66	13.51
2009	14.07	13.88	12.74	13.54	11.61	12.75	12.41	13.27
2010	13.79	13.60	12.47	13.26	11.31	12.44	12.10	12.97
2011	13.58	13.38	12.26	13.05	11.07	12.20	11.86	12.74
2012	13.48	13.28	12.16	12.95	10.95	12.07	11.73	12.62
2013	13.00	12.81	11.71	12.48	10.46	11.56	11.23	12.13
2014	13.41	13.20	12.07	12.86	10.80	11.92	11.59	12.51
2015	13.68	13.47	12.32	13.13	11.01	12.16	11.82	12.76
2016	14.21	14.00	12.80	13.64	11.46	12.66	12.30	13.27
2017	14.92	14.70	13.46	14.33	12.08	13.33	12.95	13.96
2018	15.19	14.96	13.69	14.58	12.28	13.55	13.17	14.19
2019	15.50	15.27	13.97	14.88	12.52	13.82	13.43	14.48
2020	16.07	15.83	14.49	15.43	13.01	14.35	13.95	15.03
2021	16.63	16.39	15.00	15.97	13.48	14.87	14.45	15.56
2022	17.46	17.21	15.76	16.77	14.20	15.65	15.21	16.36
2023	18.07	17.81	16.31	17.36	14.70	16.20	15.75	16.94
2024	18.71	18.44	16.89	17.97	15.22	16.77	16.31	17.53
2025	19.37	19.09	17.48	18.61	15.76	17.36	16.88	18.15
2026	20.05	19.76	18.10	19.26	16.31	17.98	17.48	18.79
2027	20.76	20.46	18.74	19.94	16.89	18.61	18.09	19.45
2028	21.49	21.18	19.40	20.65	17.48	19.26	18.73	20.14
2029	22.25	21.93	20.08	21.37	18.10	19.94	19.39	20.85
2030	23.03	22.70	20.79	22.13	18.74	20.65	20.07	21.58
2031	23.84	23.50	21.52	22.91	19.40	21.37	20.78	22.34
2032	24.69	24.33	22.28	23.71	20.08	22.13	21.51	23.13
2033	25.56	25.19	23.07	24.55	20.79	22.91	22.27	23.95
2034	26.46	26.07	23.88	25.42	21.52	23.72	23.06	24.79
2035	27.39	26.99	24.72	26.31	22.28	24.55	23.87	25.67
2036	28.35	27.95	25.59	27.24	23.06	25.42	24.71	26.57
2037	29.35	28.93	26.50	28.20	23.88	26.31	25.58	27.51
2038	30.39	29.95	27.43	29.19	24.72	27.24	26.48	28.48
2039	31.46	31.01	28.40	30.22	25.59	28.20	27.42	29.48
2040	32.57	32.10	29.40	31.29	26.49	29.20	28.38	30.52
Levelized								
(2008-2040)	17.727	17.471	15.999	17.030	14.417	15.888	15.447	16.610
(2009-2040)	17.938	17.677	16.187	17.231	14.574	16.065	15.618	16.800
5 years (2008-12)	13.863	13.672	12.539	13.331	11.383	12.516	12.176	13.043
10 years (2008-17)	13.836	13.637	12.492	13.294	11.269	12.414	12.071	12.972
15 years (2008-22)	14.427	14.218	13.021	13.859	11.732	12.929	12.570	13.517

Nominal discount rate: 4.7755%

Exhibit B-14. Avoided Cost of Gas Delivered to Retail Customers in Vermont by End Use (Gas Delivered via TransCanada Pipeline) in Nominal$/Dekatherm

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
Year	3-mon.	5-mon.	annual	6-mon.	annual	5-mon.	6-mon.	5-mon.
2007	12.14	11.90	10.66	11.53	8.65	9.89	9.52	10.65
2008	13.42	13.16	11.83	12.76	9.77	11.10	10.70	11.87
2009	13.23	12.97	11.64	12.58	9.53	10.86	10.47	11.65
2010	13.00	12.74	11.41	12.35	9.25	10.58	10.18	11.39
2011	12.83	12.57	11.24	12.17	9.02	10.35	9.96	11.18
2012	12.76	12.50	11.16	12.10	8.89	10.23	9.83	11.08
2013	12.36	12.09	10.77	11.70	8.44	9.76	9.37	10.64
2014	12.73	12.46	11.11	12.06	8.72	10.08	9.68	10.97
2015	13.00	12.72	11.33	12.31	8.89	10.27	9.86	11.19
2016	13.49	13.21	11.77	12.78	9.27	10.70	10.28	11.64
2017	14.15	13.85	12.36	13.41	9.79	11.28	10.84	12.25
2018	14.40	14.10	12.58	13.65	9.94	11.47	11.02	12.46
2019	14.70	14.39	12.84	13.93	10.14	11.69	11.23	12.71
2020	15.23	14.92	13.31	14.44	10.54	12.15	11.67	13.19
2021	15.76	15.43	13.78	14.94	10.94	12.59	12.10	13.66
2022	16.51	16.18	14.45	15.67	11.55	13.27	12.76	14.36
2023	17.10	16.75	14.96	16.22	11.95	13.74	13.21	14.87
2024	17.70	17.34	15.49	16.79	12.37	14.22	13.67	15.39
2025	18.32	17.95	16.04	17.38	12.81	14.72	14.16	15.93
2026	18.97	18.58	16.60	18.00	13.26	15.24	14.65	16.50
2027	19.64	19.24	17.19	18.63	13.73	15.78	15.17	17.08
2028	20.33	19.91	17.79	19.29	14.21	16.33	15.71	17.68
2029	21.05	20.62	18.42	19.97	14.72	16.91	16.26	18.30
2030	21.79	21.34	19.07	20.67	15.23	17.50	16.83	18.95
2031	22.56	22.09	19.74	21.40	15.77	18.12	17.43	19.61
2032	23.35	22.87	20.44	22.15	16.33	18.76	18.04	20.31
2033	24.18	23.68	21.16	22.93	16.90	19.42	18.68	21.02
2034	25.03	24.51	21.91	23.74	17.50	20.11	19.33	21.76
2035	25.91	25.38	22.68	24.58	18.11	20.82	20.02	22.53
2036	26.82	26.27	23.48	25.45	18.75	21.55	20.72	23.32
2037	27.77	27.20	24.31	26.34	19.41	22.31	21.45	24.15
2038	28.75	28.16	25.16	27.27	20.10	23.10	22.21	25.00
2039	29.76	29.15	26.05	28.23	20.81	23.91	22.99	25.88
2040	30.81	30.18	26.97	29.23	21.54	24.75	23.80	26.79
Levelized								
(2008-2040)	16.770	16.426	14.678	15.909	11.721	13.470	12.952	14.581
(2009-2040)	16.977	16.628	14.853	16.102	11.841	13.616	13.090	14.748
5 years (2008-12)	13.063	12.803	11.472	12.408	9.313	10.644	10.249	11.456
10 years (2008-17)	13.081	12.814	11.455	12.412	9.170	10.530	10.127	11.389
15 years (2008-22)	13.649	13.369	11.946	12.948	9.537	10.961	10.539	11.866

Nominal discount rate: 4.7755%

Appendix C – Detailed Input Assumptions for Electric Energy Price Forecast

Exhibit C-1. Load Allocation Exhibit[135]

Modeling Zone	2006 RSP Subarea	SMD Load Zone	State	MW	State & Peak Load					
					CT	MA	ME	NH	RI	VT
					7,252	12,561	2,013	2,313	1,855	1,046
BHE	BHE	ME	Maine	310			15.4%			
CMP	ME	ME	Maine	988			49.1%			
		NH	New Hampshire	57				2.5%		
	SME	ME	Maine	665			33.0%			
NH	NH	ME	Maine	50			2.5%			
		NH	New Hampshire	1,790				77.4%		
		VT	Vermont	70						6.7%
VT	VT	NH	New Hampshire	308				13.3%		
		VT	Vermont	902						86.2%
BOSTON	BOSTON	NEMA/Boston	Massachusetts	5391		42.9%				
		NH	New Hampshire	79				3.4%		
CMA/NEMA	CMA/NEMA	WCMA	Massachusetts	1671		13.3%				
		NH	New Hampshire	79				3.4%		
WMA	WMA	CT	Connecticut	72	1.0%					
		WCMA	Massachusetts	1,929		15.4%				
		VT	Vermont	74						7.1%
SEMA	SEMA	SEMA	Massachusetts	2811		22.4%				
		RI	Rhode Island	149					8.0%	
RI	RI	SEMA	Massachusetts	759		6.0%				
		RI	Rhode Island	1706					92.0%	
CT	CT	CT	Connecticut	3580	49.4%					
SWCT	SWCT	CT	Connecticut	2,340	32.3%					
	NOR	CT	Connecticut	1,260	17.4%					

[135] From Table 3-6 of ISO New England 2006 Regional System Plan.

Exhibit C-2. Thermal Unit Characteristics

Fuel Type	Unit Type	Size Range	Forced Outage Rate	Maintenance Outage Rate	Fixed O&M ($/kw-yr)	Var. O&M ($/MWh)	Min. Down Time (hours)	Min. Up Time (hours)	Full Load HR (btu/kwh)
Coal	ST	<=50	0.074	0.070	$79.13	$3.58	24	24	12,609
		>200	0.071	0.082	$31.97	$1.81	24	24	9,811
		50-100	0.071	0.070	$23.82	$1.28	24	24	10,650
		100-200	0.064	0.070	$39.78	$1.84	24	24	10,700
Gas/Oil	GT	<=50	0.068	0.040	$29.43	$2.75	1	1	12,459
	ST	<=50	0.073	0.070	$30.43	$2.88	8	6	13,957
		>200	0.060	0.125	$18.42	$1.26	8	12	10,735
		50-100	0.142	0.070	$15.13	$1.42	8	6	11,779
		100-200	0.065	0.115	$17.21	$1.47	8	8	11,188
LFG	GT	<=50	0.063	0.030	$19.54	$3.31			10,000
	IC	<=50	0.022	0.040	$61.01	$4.34			10,036
	ST	<=50	0.068	0.070	$30.65	$3.86			11,826
MSW	ST	<=50	0.068	0.070	$24.25	$0.96	8	6	11,671
		50-100	0.068	0.070	$24.06	$0.93	8	6	11,772
Natural Gas	CC	>200	0.055	0.041	$11.42	$2.19	20	8	7,070
		50-100	0.059	0.080	$14.69	$0.88	22	8	8,070
		100-200	0.059	0.074	$22.25	$1.69	8	8	8,558
	CG	<=50	0.059	0.080	$7.57	$0.66	8	8	10,000
		50-100	0.042	0.051	$10.92	$3.53	4	4	10,928
		100-200	0.054	0.072	$12.86	$1.58	18	7	8,689
	GT	<=50	0.053	0.040	$10.08	$2.01	2	1	10,863
		50-100	0.043	0.040	$12.77	$0.59	3	2	9,919
	ST	>200	0.063	0.150	$17.00	$1.42	8	10	10,313
Nuclear	NU	>200			$92.63	$4.48		168	10,077
Oil	CC	100-200	0.059	0.080	$19.39	$2.12	8	8	8,000
	CG	<=50	0.068	0.040	$5.43	$1.62	1	1	13,726
	GT	<=50	0.065	0.034	$9.47	$2.56	1	1	13,955
		50-100	0.043	0.040	$5.66	$0.60	3	2	12,686
	IC	<=50	0.142	0.070	$20.20	$2.21	1	1	10,370
	ST	<=50	0.130	0.071	$13.97	$1.34	8	6	13,417
		>200	0.063	0.124	$17.92	$1.43	12	14	10,385
		50-100	0.142	0.070	$21.80	$1.75	8	6	10,500
		100-200	0.069	0.120	$18.18	$1.62	8	8	11,202
Other	CG	100-200	0.064	0.070	$23.74	$0.95	8	8	11,050
	ST	<=50	0.068	0.070	$23.80	$0.97	8	6	10,000
Wind	WT	<=50			$20.61	$0.00			
Wood	ST	<=50	0.068	0.070	$26.44	$1.33	8	6	11,874
		50-100	0.054	0.070	$30.45	$1.70	8	6	11,927

Exhibit C-3. Summary of State RPS Requirements and Qualifying Technology Types

Technology	CT Classes			MA	ME	RI	VT	NH			
	I	II	III					I New	II New	III Existing	IV Existing
Solar thermal	•	•		•	•	•		•			
Biomass thermal								•			
Photovoltaic	•	•		•	•	•		•	•		
Ocean thermal	•	•		•	•	•		•			
Wave	•	•		•	•	•		•			
Tidal	•	•		•	•	•		•			
Wind	•	•		•	•	•	•	•			
Biomass	Sustainable, low emission	•		Low-emission, technology	•	•	•	< = 50 MW		< = 25 MW	
Hydro	< = 5 MW	< = 5 MW			•	< = 30 MW	< = 200 MW				< = 5 MW
Landfill gas	•			•	•		•	•		•	
Sewage plant waste							•	•		•	
Fuel cells	•			w/ RE fuels	•	w/ RE fuels		w/ RE fuels			
Geothermal					•	•		•			
MSW		•			w/ recycling						
CHP			• (a)		•						
Energy efficiency			• (a)								
	Percent Requirement										
Year	I	II or I	III		(b)	(c)		I	II	III	IV
2007	3.5%	3% in all years	1.0%	3.0%	30% in all years	3.0%	Incremental growth between 2005 and 2012	0.0%	0.0%	0.0%	0.0%
2008	5.0%		2.0%	3.5%		3.5%		0.0%	0.0%	3.5%	0.5%
2009	6.0%		3.0%	4.0%		4.0%		0.5%	0.0%	4.5%	1.0%
2010	7.0%		4.0%	5.0%		4.5%		1.0%	0.0%	5.5%	1.0%
2011	7.0%		4.0%	6.0%		5.5%		2.0%	0.1%	6.5%	1.0%
2012	7.0%		4.0%	7.0%		6.5%		3.0%	0.2%	6.5%	1.0%
2013	7.0%		4.0%	8.0%		7.5%		4.0%	0.2%	6.5%	1.0%
2014	7.0%		4.0%	9.0%		8.5%		5.0%	0.3%	6.5%	1.0%
2015	7.0%		4.0%	10.0%		10.0%		6.0%	0.3%	6.5%	1.0%
2016	7.0%		4.0%	11.0%		11.5%		7.0%	0.3%	6.5%	1.0%
2017	7.0%		4.0%	12.0%		13.0%		8.0%	0.3%	6.5%	1.0%
2018	7.0%		4.0%	13.0%		14.5%		9.0%	0.3%	6.5%	1.0%
2019	7.0%		4.0%	14.0%		16.0%		10.0%	0.3%	6.5%	1.0%
2020	7.0%		4.0%	15.0%		16.0%		11.0%	0.3%	6.5%	1.0%
2021	7.0%		4.0%	16.0%		16.0%		12.0%	0.3%	6.5%	1.0%
2022	7.0%		4.0%	17.0%		16.0%		13.0%	0.3%	6.5%	1.0%
Use Generator Information System (GIS) renewable energy certificates?	Yes			Yes	Yes	Yes	Yes	Yes			
Renewable energy certificates outside ISO New England	New York only until 2010			w/ deliverability		w/ deliverability	w/ deliverability				
Notes:											

Appendix D – Usage Guide for Avoided Energy Supply Costs

A. General

The avoided electricity supply cost workbook consists of a worksheet for common inputs and individual worksheets with avoided supply costs for the following geographic areas:

- Maine
- Vermont
- New Hampshire
- Connecticut (Statewide)
- Massachusetts (Statewide)
- Rhode Island
- SEMA (Southeast Massachusetts)
- WCMA (West-Central Massachusetts)
- NEMA (Northeast Massachusetts)
- Rest of Massachusetts (Massachusetts excluding NEMA)
- Norwalk/Stamford
- Southwest Connecticut, including Norwalk/Stamford
- Southwest Connecticut, excluding Norwalk/Stamford
- Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

Notifications

All present values and levelized costs in the exhibits and Avoided Cost workbook were computed using a real discount rate of 2.22%. Present values are discounted to 2007. Inflation rates of 2.9% for 2005–2006 and 2.5% for 2006–2007 were used to compare historical prices to these forecasts.

The avoided energy costs are computed for the aggregate load shape in each zone by costing period, and are applicable to DSM programs reducing load roughly in proportion to existing load. Other resources, such as load management and distributed generation, may have very different load shapes and significantly different avoided energy costs. Baseload resources, such as combined-heat-and-power (CHP) systems, would tend to

have lower avoided costs per kWh. Peaking resources, such as most non-CHP distributed generation and load management, would tend to have higher avoided costs per kWh.

B. Overview of Avoided Costs

Each worksheet for a geographic area contains the following data for estimating the benefits of DSM.

- **Avoided Energy Costs:** Avoided energy costs are presented by year for four energy costing periods – Winter Peak, Winter Off-Peak, Summer Peak, and Summer Off-Peak. Avoided energy cost in each period is calculated as (relevant avoided wholesale energy cost + cost of compliance with RPS) * (1 + retail adder).
- **Annual Market Capacity Value Avoided Cost:** The avoided capacity cost is presented for each year stating in 2010. Avoided capacity cost in each year is calculated as (market value of capacity in the FCM assuming no new DSM increased by the required reserve margin) *(1 + retail adder) *(1 + line losses to the ISO delivery points).
- **DRIPE:** DRIPE energy values are presented by year for the four energy costing periods. DRIPE capacity values are presented for each year starting in 2010. It is recommended that these be included in analyses of DSM, unless specifically excluded by state or local law or regulation. It would be useful in any case to show the cost-benefit results with and without the DRIPE benefits.
- **CO_2 Environmental Externalities:** CO_2 externality values are presented by year for the four energy costing periods. It is recommended that these be included in analyses of DSM, unless specifically excluded by state or local law or regulation. It would, however, be useful in any case to show the cost-benefit results with and without the CO_2 externalities included.

User-Specified Inputs

Program administrators are responsible for developing and applying losses from the ISO delivery points to the end use for their specific system when applying the avoided energy costs and avoided capacity costs.

Program Administrators have the ability to use different values for certain inputs if appropriate for a particular application. Those inputs are the **retail adder, capacity factor, real discount rate,** and **zonal summer on-peak capacity factor**. The default values for these inputs are provided in the "Inputs" worksheet. The avoided cost calculations in the worksheet for each zone use those default values via a link to the Inputs worksheet. If a user wishes to specify a different value for any of those inputs, that user-specified value should be entered directly in the relevant worksheet. This will preserve the default values in the Inputs worksheet.

Program administrators are responsible for developing and applying estimates of avoided transmission and distribution costs for their specific system. A suggested approach to developing those estimates is discussed below.

C. Guide to Applying the Avoided Costs

The benefits of DSM should be estimated from the appropriate avoided-cost exhibit as the sum over the years of:

1. reduction in winter peak energy at the end use
   × winter peak energy losses from the ISO delivery points to the end use[136]
   × the *Winter Peak Energy* value for that year;

2. reduction in winter off-peak energy at the end use
   × winter off-peak energy losses from the ISO delivery points to the end use
   × the *Winter Off-Peak Energy* value for that year;

3. reduction in summer peak energy at the end use
   × summer peak energy losses from the ISO delivery points to the end use
   × the *Summer Peak Energy* value for that year;

4. reduction in summer off-peak energy at the end use
   × summer peak off-energy losses from the ISO delivery points to the end use
   × the *Summer Off-Peak Energy* value for that year;

5. reduction in capacity costs estimated either as

   a) reduction at the time of summer coincident peak at the end use
      × summer peak-hour losses from the ISO delivery points to the end use
      × the *Annual Market Capacity Value* for that year;

   or alternatively,

   b) reduction in summer peak energy at the end use
      × summer peak energy losses from ISO delivery to the end use
      × the *On-Peak Summer Capacity Value* for that year;

6. If the avoided costs are to include DRIPE, the avoided costs should be increased as follows:

   a) If the savings persist for at least 4 years (6 years for capacity), use the values in the columns applicable to the efficiency program implementation year to calculate the sum of:

[136] Each set of losses should be computed by the program administrator for its specific system.

i. reduction in annual winter peak energy at the end use
× winter peak energy losses from ISO delivery to the end use[137]
× the present value line for DRIPE Winter Peak Energy;[138]

ii. reduction in annual winter off-peak energy at the end use
× winter off-peak energy losses from ISO delivery to the end use
× the present value line for DRIPE Winter Off-Peak Energy;

iii. reduction in annual summer peak energy at the end use
× summer peak energy losses from ISO delivery to the end use
× the present value line for DRIPE Summer Peak Energy;

iv. reduction in annual summer off-peak energy at the end use
× summer off-peak energy losses from ISO delivery to the end use
× the present value line for DRIPE Summer Off-Peak Energy;

v. reduction at the time of summer coincident peak at the end use
× summer peak-hour losses from ISO delivery to the end use
× the present value line for DRIPE Annual Market Capacity Value.

b) If savings persist for shorter periods, or if inclusion of present values is inconvenient in the benefit-cost model, DRIPE should be computed in the same manner as the direct avoided costs, as the product of load reductions and the annual DRIPE price

7. If the avoided costs are to include carbon externalities, the avoided costs should be increased as follows:[139]

a) reduction in winter peak energy at the end use
× winter peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Winter Peak Energy* value for that year,

b) reduction in winter off-peak energy at the end use
× winter off-peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Winter Off-Peak Energy* value for that year,

[137] The loss factors relevant throughout this list should be (power at ISO delivery) ÷ (power at the end use), and will be between 1.00 and 1.20. For some utilities, losses are reported separately as percentage losses (a) from ISO delivery to the distribution substation, and (b) from the substation to the customer; the overall loss factor can be computed as [1 + (a)] × [1 + (b)].

[138] The user can change the real discount rate input to match the discount rate used in its benefit-cost model.

[139] One could also make an adjustment for losses from the generator to the PTF, but that is likely more precision than is warranted by the externality value itself.

c) reduction in summer peak energy at the end use
× summer peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Summer Peak Energy* value for that year,

d) reduction in summer off-peak energy at the end use
× summer off-peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Summer Off-Peak Energy* value for that year,

8. If the avoided costs are to include avoided transmission and distribution costs on the program administrator's system, the avoided costs should be increased as follows:

a) Reduction in the peak demand used in estimating avoided transmission and distribution costs at the end use
× capacity losses at those peak hours from ISO delivery to the end use
× the utility-specific estimate of avoided T&D costs in $/kW-year.[140]

D. Guide to Exhibit Structure and Terminology

Each of the avoided-cost exhibits has the same structure. Reading from left to right, the structure is as follows:

i. Avoided Costs

(a) Winter Peak Energy Avoided Cost ($/kWh) [141]

The 16-hour block 6am – 10pm (the hours ended 700 through 2200), Monday – Friday (except ISO holidays), in the months of January – May and October – December. Avoided energy cost in each period is calculated as (relevant avoided wholesale energy cost + cost of compliance with RPS) * (1 + retail adder).

(b) Winter Off-Peak Energy Avoided Cost ($/kWh)

All other hours – 10pm - 6am (the hours ended 2300 through 600), Monday – Friday, all day on Saturday and Sunday, and ISO holidays – in the months of January – May and October – December. Avoided energy cost in each period is calculated as (relevant avoided wholesale energy cost + cost of compliance with RPS) * (1 + retail adder).

(c) Summer Peak Energy Avoided Cost ($/kWh)

The 16-hour block 6am – 10pm (the hours ended 700 through 2200), Monday – Friday (except ISO holidays), in the months of June – September. Avoided energy cost in each

[140] Most demand-response and load-management programs will not avoid transmission and distribution costs, since they are as likely to shift local loads to new peak hours as to reduce local peaks.

[141] ISO holidays are New Year's Day, Memorial Day, July 4, Labor Day, Thanksgiving, and Christmas.

period is calculated as (relevant avoided wholesale energy cost + cost of compliance with RPS) * (1 + retail adder).

(d) Summer Off-Peak Energy Avoided Cost ($/kWh)

All other hours – 10pm – 6am (the hours ended 2300 through 600), Monday – Friday, all day on Saturday and Sunday, and ISO holidays in the months of June – September. Avoided energy cost in each period is calculated as (relevant avoided wholesale energy cost + cost of compliance with RPS) * (1 + retail adder).

(e) Annual Market Capacity Value Avoided Cost ($/kW-yr)

Annual Market Capacity Value Avoided Cost is calculated as the market-clearing price in the forward capacity market, estimated at the estimated cost of new entry, increased by the required reserve margin to represent costs per kilowatt of load. These values also include line losses to the ISO delivery points. The annual capacity requirement for load is determined by the load's contribution to the system coincident peak, which occurs on a summer weekday, usually in the months of July and August, in the hours ending 1500–1700.[142]

ii. Demand-Reduction-Induced Price Effects (DRIPE)

The next two sections of each exhibit provide the estimates of DRIPE developed in this project. The first section applies to measures implemented in 2008, the second to measures implemented in 2009. Each energy period and capacity has annual entries for a few years, as well as a present value at the bottom of the exhibit. As discussed below, most applications of these avoided cost components can use the present values directly, without using the annual values. The annual values may be more convenient for use in some economic-evaluation models.

Some interpretations of the societal test and the total resource cost test will include DRIPE while others will exclude DRIPE. That choice is left to the program administrators and/or their regulators.

iii. CO_2 Externality

This section provides estimates of CO_2 externality values developed in this project. Each energy period has annual entries.

iv. Forward Capacity Market (FCM) Revenue

To the right of the CO_2 externality values, each avoided-cost worksheet provides estimates of the FCM revenues that the program administrator could receive by bidding DSM programs into the forward capacity market auction. These are not avoided costs and should not be included in any calculation of avoided costs. Instead these estimates are

[142] In the last ten years, the coincident peak has occurred outside these hours only twice, at hour ending 1300 in late June and at hour ending 1400 in July.

simply provided as a convenience to program administrators who may need to provide an estimate to their regulator.

Most DSM programs are likely to participate in the FCM as either On-Peak Demand Resources (a category designed for non-weather-sensitive savings) or Seasonal Peak Demand Resources (designed for weather-sensitive savings).These revenues would be offsets to program costs for budgeting purposes. These revenues would not be TRC benefits for New England customers as a whole, since customers will be paying the FCM charges, as well as getting the benefits of the FCM revenues offsetting DSM costs.

(f) Load Reduction Value in Capacity Terms

Program administrators should multiply the unit FCM revenue values ($/kW) from the workbook by the appropriate load reduction in June, July, August, December, and January. The applicable time periods for each category of resource in those 5 months are:

- On-Peak Demand Resources - average load reduction during non-holiday weekday hours of:
  - 1 PM to 5 PM (hours ending 1400 to 1700) in June, July and August
  - 5 PM to 7 PM (hours ending 1800 and 1900) in December and January
- Seasonal Peak Demand Resources – the average load reduction during non-holiday weekday hours during which real-time system hourly load exceeds 90% of the most recent "50/50" System Peak Load Forecast for the season.[143]

(The unit FCM revenue values in the workbook reflect the FCM revenue values that the resource will receive in the remaining months of February, March, April, May, September, October, and November).

(g) Load Reduction Value in Energy Terms

As an alternative to the recommended method described above, program administrators may wish to calculate the FCM benefits in $/kWh terms. The column to the right of the FCM Revenues section in each zonal spreadsheet therefore includes the capacity avoided costs in $/kWh, computed from the 2006 summer on-peak load factor for each zone:[144]

(summer on-peak energy ÷ summer on-peak hours) ÷ load at the system peak

This value is most likely to be useful for comparing avoided capacity costs to avoided energy costs. If it is used for screening, this value should be multiplied by the summer on-peak savings.

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[143] If no high-load hours occur in the month, the ISO will estimate the potential load reduction from prior experience or engineering data.

[144] Monthly on-peak energy for the Connecticut sub-zones was not readily available from the ISO, so the load factors for those sub-zones were estimated as the Connecticut summer on-peak load factor times the ratio of the sub-zone all-hours summer load factor to the Connecticut all-hours summer load factor.

v. Input Values

To the right of the FCM values discussed above, each zonal worksheet contains the wholesale market prices and renewable-energy-credit prices applicable to that zone. These values do not reflect the addition of losses and retail adders. Users should not normally need to use these input values directly, or to modify these values.

E. Levelization

Along the bottom of the tables in each zonal worksheet, there are real-levelized costs for each of the direct avoided costs. These values are calculated for various periods, using a 2.2% real discount rate and the 2.5% inflation rate assumed throughout this project. For DRIPE, whose effects are experienced over only a few years, the spreadsheet includes the present value of the energy effect per annual MWh and the capacity effect per kilowatt of load reduction, for the convenience of the program administrators. Inclusion of DRIPE would add roughly one to three years to the avoided-cost benefits.

F. Utility-Specific Costs to be Added/Considered by Program Administrators

i. Losses from the ISO Delivery Point to the End Use

The avoided energy and capacity costs, and the estimates of DRIPE, include energy and capacity losses on the ISO-administered pool transmission facilities (PTF), from the generator to the delivery points at which the PFT system connects to local non-PTF transmission or to distribution substations. The exhibits **DO NOT** include the following losses:

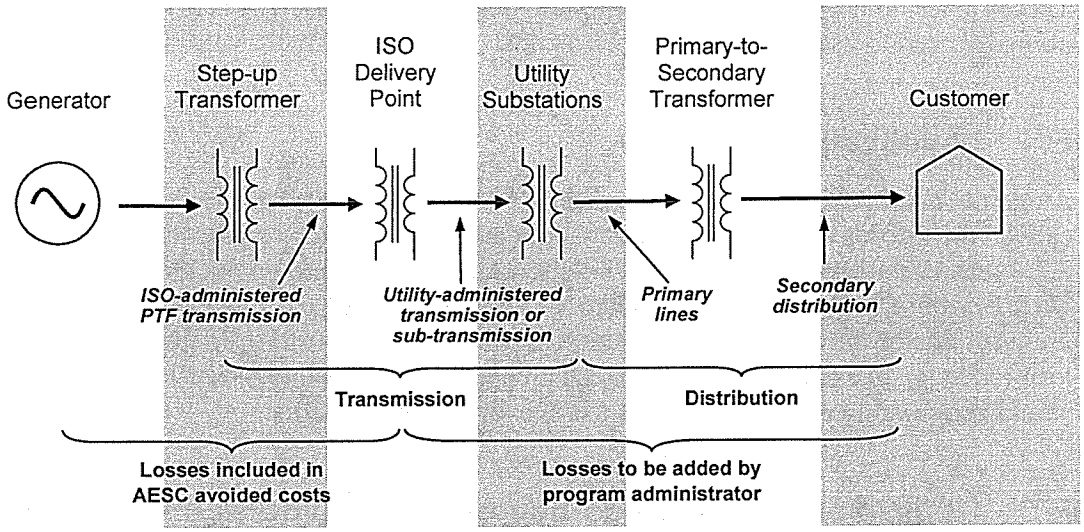
- over the non-PTF transmission substations and lines to distribution substations;
- in the distribution substations,
- from the distribution substations to the line transformers on the primary feeders and laterals,[145]
- from the line transformers over the secondary lines and services to the customer meter,[146]
- from the customer meter to the end use.

[145] In some cases, this may involve multiple stages of transformers and distribution, as (for example) power is transformed from 115kV transmission to 34kV primary distribution and then to 14 kV primary distribution and then to 4 kV primary distribution, to which the line transformer is connected.

[146] Some customers receive their power from the utility at primary voltage. Since virtually all electricity is used at secondary voltages, these customers generally have line transformers on the customer side of the meter and secondary distribution within the customer facility.

The exhibit below provides a simplified illustration of the many types of losses on transmission and distribution systems.

Exhibit D-1. Delivery System Structure and Losses



In most cases, DSM program administrators measure demand savings from DSM programs at the end use. The program administrator should estimate the losses from delivery points to the end uses. If the energy delivered to the utility at the PTF is *a*, losses are *b*, and the delivered power is *c*,

- losses as a fraction of deliveries to the utility are $b \div a$,
- losses as a fraction of deliveries to customers are $b \div c$.

Hence, each kilowatt or kilowatt-hour saved at the end use saves $1 + b/c$. The program administrator should estimate that ratio and multiply the end-use savings or benefits by that loss ratio. Loss ratios will be generally higher for higher-load periods than lower-load periods, since losses in wires (both within transformers and in lines) vary with the square of the load, for a given voltage and conductor type.

If the change in load does not change the capacity of the transmission and distribution system, the losses should be computed as marginal losses, which are roughly twice the percentage as average line losses for the same load level.[147] Energy savings and/or growth do not generally result in changing the wire sizes. Hence, for energy avoided costs, losses are estimated on a marginal basis, so *a, b*, and *c* above are increments or derivatives, rather than total load values.

If the change in load results in a proportional change in transmission and distribution capacity, losses should be computed as the average losses for that load level. If the program administrator treats all load-carrying parts of the transmission and distribution as

[147] In this sense, "line losses" does not include the no-load losses that result from eddy currents in the cores of transformers. These are often called "iron" losses (since transformer cores were historically made of iron), in contrast to the load-related "copper" losses of the lines and transformer windings.

avoidable and varying with peak load, then only average losses should be applied to avoided capacity costs.

ii. Avoided Transmission and Distribution Costs

The avoided costs developed in this project do not include any avoided transmission and distribution (T&D) costs. Each program administrator should add avoided T&D costs, in $/kW of reduced summer and/or winter peak demand, as appropriate for the specific service territories.[148] In southern New England, the vast majority of distribution equipment peaks in the summer, so allocating all avoided T&D costs to the summer would be reasonable. In northern New England, especially where areas have significant electric heating load, much of the T&D costs will be driven by winter peaks.

The following is a description of a process that could be used to estimate the percent of transmission and distribution capital expenditures that are avoidable.

The standard approach to estimating marginal or avoidable T&D cost is to estimate the following for some period of time (typically a decade):

$$\frac{\text{avoidable capital investment}}{\text{load growth}} + \text{related O\&M and overheads}$$ [149]

Historical analyses generally use load and plant-additions data from the FERC Form 1 filed annually by each investor-owned utility. For comparability, the additions in each year must be restated to current dollars, such as with the Handy-Whitman indices for the various accounts.[150]

Some utilities have estimated marginal or avoidable T&D investments from projections of investments over the next five or ten years. If those projections are comprehensive, they can be used in much the same manner as the historical data.[151]

Some T&D additions are required regardless of load growth, while other expenditures are required just to replace retirements of existing plant. The T&D cost data should be adjusted to remove (1) replacements of retired plant and (2) customer-related distribution costs.[152]

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[148] Avoided transmission costs and avoided distribution costs are usually calculated separately, but may be combined in the evaluation of efficiency measures.

[149] This Task did not include estimation of avoidable T&D O&M expenses. These are generally estimated in $/kW-year terms, or as a percentage of plant in service, for the O&M accounts for load-related equipment.

[150] Ideally, the analysis would recognize that some load is served by the utility at transmission or primary-distribution voltages, and that those customers provide transformers and internal secondary distribution, which is also an avoidable cost.

[151] The system load data may require adjustments for customers served at transmission voltage, migration of wholesale customers to wheeling service, and changes in geographical service territory.

[152] The categories used in T&D budgeting do not always fit cleanly into categories useful for determining avoidable costs. For example, a "reliability project" may consist of replacing aging cable that has been causing outages (a replacement), addition of protective systems that were omitted when the substation

iii. Replacements

Since the actual replacement is likely to have greater capacity than the original installation (to accommodate the load growth that has occurred the preceding years), the cost of replacement equipment will tend to overstate the portion of investment costs attributable to unavoidable retirements. In the estimate of the replacement cost (the original cost inflated to current dollars), the incremental cost of any equipment upgrades is correctly treated as a load-related cost.[153]

The inflated retirement cost should be based on the average age, not the useful life, of the plant. If all plant survived to the end of its useful life, 30 to 40 years for T&D, the replacement-to-original cost ratio would be large, and the net load-related additions (net of retirements) would be small. But, the average age of retired plant is much lower than the useful life.[154] Retirements in any year reflect a mixture of vintages and most of the equipment in the system is relatively new. Further, the younger equipment is a higher percentage of the dollars retired than it is of the number of items retired, since the younger installations were built in inflated dollars.

iv. Customer-Related Distribution Costs

Some investments, such as meters, are required primarily to serve new customers, regardless of demand levels. A portion of distribution poles, lines and line transformers are also necessary to reach new customers, especially in rural areas.

The T&D investments are rarely classified in a manner consistent with determining whether they are avoidable through load reductions. For example, a reliability problem may arise due to higher loads, and some of the investment added to serve "new business" may be avoidable by reducing the load of the new customer and its neighbors. As an approximation, two adjustments can be made to the net distribution additions (net of retirements):

- Omit expenditures on meters, services, installations and leased property on customer premises, and street lighting and signal systems, even though a portion of service costs are load-related (especially where services are being upgraded to carry higher amperage).

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or feeder was originally built (a deferred cost of earlier growth), or looping feeders to reduce outage rates (which may be driven by rising loads on the feeders or by changing attitudes towards outages). The first example is not avoidable, the second example is a measure of future upgrades that may be needed for today's load-related projects, and the third may be load related or not, depending on the justification for improving reliability on this part of the distribution system. The identification of avoidable investments in T&D planning documents requires thoughtful review, and the process will vary among utilities, due to differences in the planning documents and system conditions.

[153] Some replacements may actually be load-related. For example, some equipment may wear out prematurely because of overloading, or retired prematurely in order to replace it with larger capacity equipment.

[154] The depreciation study will be useful in determining the average age of retired plant.

- Reduce expenditures in all distribution accounts except substations by a percentage determined to be customer-related.

The "minimum system" method is frequently used to estimate the portion of plant that is not avoidable. It attempts to estimate the cost of the distribution system as if each unit of equipment were the minimum-sized unit that would ever be used. The demand-related portion of the investment is the increment over the cost of the minimum-sized equipment. To maintain consistency in the computation of avoidable cost per kilowatt, the loads served by that minimum-sized equipment should be removed along with the cost of that equipment.

It is likely that multiplying the cost of the minimum-sized equipment times the number of units overstates the customer-related distribution investment, since demand affects the number of transformers and the feet of conductor and conduit, as well as the size of the transformers and lines.

v. Avoidable Percent of T&D Capital

The percent of T&D capital expenditures that is avoidable would be the value estimated from the adjustment above for replacements and customer-related plant, divided by the gross expenditures. This percentage is not really needed once the adjusted investments have been estimated. An avoidable percentage estimated from one data set (e.g., historical FERC data) should not be applied to a different data set (e.g., current utility forecasts), unless the two data sets can be determined to be equally comprehensive.

Appendix E - Avoided Electric Costs (Revised 8/31/07)

Pages E-1 through E-32 present avoided costs in Year 2007$. Pages E-33 through E-63 present avoided costs in Nominal$

General Notes

Losses

All costs include losses on the ISO-administered transmission system, to the PTF delivery nodes.
DSM savings at the meter should be increased to include avoided losses from ISO delivery points to the meter, including losses on the distribution and any transmission below the ISO level.

All constant dollar avoided costs are in Year 2007 Dollars
All present values are in Year 2007 Dollars

Energy periods are:

Peak	Monday through Friday 6am - 10pm, excluding ISO holidays
Off-peak	All other hours
Summer	June through September
Winter	October through May

Capacity

Avoided capacity cost is per kW of load coincident with ISO-NE annual peak
Avoided capacity cost includes only the ISO FCM market. Avoided transmission and distribution costs should be added by the program administrator.
Avoided capacity cost is also included in $/kWh of summer peak energy, for the convenience of some program administrators.
Avoided capacity costs can be included in $/kW-yr or $/kWh, but not both.
FCM revenue is for the convenience of the program administrator, in estimating offsets to its budget. This values should not be included as an avoided cost.
FCM revenue periods

Summer	April through November
Winter	December through March

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

Constant Dollar Worksheet Inputs

Note: This version has inputs for FCM phase-in in PY 2010-11 through 2012-13, assuming that the PCM price may be depressed in the first couple years due to demand-reduction bids. The phase-in is reflected directly in the capacity revenue column. The avoided capacity cost uses the average between 100% and the phased-in price.

Retail Adder	10%	except for Vermont, PSNH
Real Discount Rate	2.22%	
Capacity Losses to ISO delivery	3.4%	

Development of Load Factors

Summer Peak GWh	CT	ME	NH	RI	VT	NEMA	SEMA	WCMA	MA	non-NE MA
Sep-06	1,215	410	470	348	164	1,008	585	625		
Aug-06	1,742	525	610	469	278	1,374	842	881		
Jul-06	1,559	451	578	417	241	1,267	772	769		
Jun-06	1,530	500	538	389	241	1,217	686	803		
Total Summer	6,046	1,886	2,197	1,623	924	4,867	2,885	3,078	10,830	5,963
Peak 2Aug06 HE1400	7,367	2,022	2,452	1,960	1,036	5,582	3,712	3,760	13,054	7,472
Summer Peak Load Factor	60.3%	68.6%	65.9%	60.9%	65.6%	64.1%	57.2%	60.2%	61.0%	58.7%

Please note: CT subzones estimated as (CT peak lf) * (subzone summer lf)/(CT summer lf), summer lfs from ISO SMD_monthly.xls

		Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
	tons/MWh	0.61	0.60	0.68	0.66
	$/ton externality	$/kWh externality			
2007	60.00	0.037	0.036	0.041	0.040
2008	60.00	0.037	0.036	0.041	0.040
2009	57.79	0.035	0.035	0.039	0.038
2010	57.63	0.035	0.035	0.039	0.038
2011	57.47	0.035	0.034	0.039	0.038
2012	50.54	0.031	0.030	0.034	0.033
2013	48.44	0.030	0.029	0.033	0.032
2014	46.34	0.028	0.028	0.032	0.031
2015	44.24	0.027	0.027	0.030	0.029
2016	42.14	0.026	0.025	0.029	0.028
2017	40.04	0.024	0.024	0.027	0.026
2018	37.94	0.023	0.023	0.026	0.025
2019	35.84	0.022	0.022	0.024	0.024
2020	33.73	0.021	0.020	0.023	0.022
2021	32.68	0.020	0.020	0.022	0.022
2022	31.63	0.019	0.019	0.022	0.021

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.099	0.073	0.104	0.076	-										
2008	0.111	0.083	0.106	0.081	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.104	0.079	0.107	0.073	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.101	0.075	0.104	0.071	60.5	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.097	0.071	0.103	0.069	109.1	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.098	0.072	0.106	0.070	122.1					90	0.028	0.023	0.059	0.030	140
2013	0.093	0.066	0.100	0.065	129.6					40					90
2014	0.094	0.066	0.099	0.066	129.6										40
2015	0.092	0.066	0.100	0.065	129.6										
2016	0.093	0.068	0.102	0.067	129.6										
2017	0.097	0.070	0.106	0.069	129.6										
2018	0.095	0.070	0.104	0.069	129.6										
2019	0.094	0.068	0.104	0.068	129.6										
2020	0.096	0.071	0.108	0.069	129.6										
2021	0.096	0.071	0.110	0.069	129.6										
2022	0.100	0.072	0.113	0.071	129.6										
2023	0.101	0.073	0.115	0.072	129.6										
2024	0.103	0.074	0.117	0.073	129.6										
2025	0.104	0.075	0.118	0.074	129.6										
2026	0.106	0.076	0.120	0.075	129.6										
2027	0.107	0.077	0.122	0.076	129.6										
2028	0.109	0.078	0.123	0.078	129.6										
2029	0.110	0.079	0.125	0.079	129.6										
2030	0.112	0.080	0.127	0.080	129.6										
2031	0.114	0.082	0.129	0.081	129.6										
2032	0.115	0.083	0.131	0.082	129.6										
2033	0.117	0.084	0.133	0.083	129.6										
2034	0.119	0.085	0.135	0.085	129.6										
2035	0.120	0.086	0.137	0.086	129.6										
2036	0.122	0.088	0.139	0.087	129.6										
2037	0.124	0.089	0.141	0.088	129.6										
2038	0.126	0.090	0.143	0.090	129.6										
2039	0.127	0.091	0.145	0.091	129.6										
2040	0.129	0.093	0.147	0.092	129.6										
Levelized															
(2008-2040)	0.105	0.076	0.116	0.075	114.9	0.006	0.005	0.012	0.006	13.4	0.006	0.004	0.012	0.006	10.3
(2009-2040)	0.105	0.076	0.116	0.075	120.0	0.005	0.004	0.011	0.005	14.0	0.006	0.005	0.012	0.006	10.7
5 years (2008-12)	0.102	0.076	0.105	0.073	56.8	0.028	0.023	0.058	0.030	59.0	0.028	0.022	0.057	0.029	26.8
10 years (2008-17)	0.098	0.072	0.103	0.070	91.2	0.015	0.012	0.031	0.016	35.1	0.015	0.012	0.030	0.015	26.9
15 years (2008-22)	0.098	0.071	0.105	0.070	102.6	0.010	0.008	0.022	0.011	24.6	0.010	0.008	0.021	0.011	18.9
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9
PV to 2009											0.135	0.109	0.279	0.141	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.089	0.064	0.093	0.067		0.175	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.098	0.073	0.094	0.071		0.222	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.092	0.070	0.095	0.064		0.233	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.074	0.090	0.066	0.092	0.062	67	0.233	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.133	0.086	0.062	0.091	0.060	114	0.211	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.148	0.087	0.064	0.095	0.061	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.158	0.083	0.059	0.090	0.058	114	0.167	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.158	0.084	0.059	0.089	0.059	114	0.145	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.158	0.082	0.059	0.090	0.058	114	0.123	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.158	0.084	0.061	0.092	0.060	114	0.099	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.158	0.087	0.063	0.095	0.062	114	0.074	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.158	0.086	0.063	0.094	0.063	114	0.049	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.158	0.085	0.062	0.095	0.061	114	0.025	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.158	0.087	0.064	0.098	0.063	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.158	0.087	0.064	0.100	0.063	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.091	0.065	0.103	0.065	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.092	0.066	0.104	0.066	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.093	0.067	0.106	0.067	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.095	0.068	0.107	0.068	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.096	0.069	0.109	0.069	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.097	0.070	0.111	0.070	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.099	0.071	0.112	0.071	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.100	0.072	0.114	0.072	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.102	0.073	0.115	0.073	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.103	0.074	0.117	0.074	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.105	0.075	0.119	0.075	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.106	0.076	0.121	0.076	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.108	0.077	0.122	0.077	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.109	0.079	0.124	0.078	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.111	0.080	0.126	0.079	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.113	0.081	0.128	0.080	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.114	0.082	0.130	0.081	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.116	0.083	0.131	0.083	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.117	0.084	0.133	0.084	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.137							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.140							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.015							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.086							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.111							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	69%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Maine					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.082	0.061	0.082	0.063	-										
2008	0.092	0.070	0.087	0.066	-	0.015	0.012	0.024	0.010	-	-	-	-	-	-
2009	0.089	0.068	0.083	0.063	-	0.044	0.037	0.069	0.030	-	0.015	0.012	0.024	0.010	-
2010	0.085	0.063	0.082	0.060	60.5	0.041	0.034	0.065	0.028	72	0.044	0.037	0.069	0.030	-
2011	0.081	0.061	0.081	0.058	109.1	0.025	0.020	0.040	0.017	140	0.041	0.034	0.065	0.028	-
2012	0.083	0.062	0.085	0.060	122.1					90	0.025	0.020	0.040	0.017	140
2013	0.079	0.058	0.081	0.057	129.6					40					90
2014	0.082	0.059	0.083	0.058	129.6										40
2015	0.081	0.059	0.084	0.057	129.6										
2016	0.083	0.060	0.087	0.060	129.6										
2017	0.085	0.062	0.089	0.060	129.6										
2018	0.082	0.062	0.087	0.060	129.6										
2019	0.083	0.060	0.091	0.060	129.6										
2020	0.084	0.061	0.091	0.060	129.6										
2021	0.085	0.063	0.093	0.061	129.6										
2022	0.087	0.064	0.097	0.062	129.6										
2023	0.088	0.065	0.098	0.062	129.6										
2024	0.090	0.066	0.100	0.063	129.6										
2025	0.091	0.067	0.101	0.064	129.6										
2026	0.092	0.068	0.102	0.065	129.6										
2027	0.094	0.069	0.104	0.066	129.6										
2028	0.095	0.070	0.105	0.067	129.6										
2029	0.096	0.071	0.107	0.068	129.6										
2030	0.098	0.072	0.109	0.069	129.6										
2031	0.099	0.073	0.110	0.070	129.6										
2032	0.101	0.074	0.112	0.071	129.6										
2033	0.102	0.075	0.113	0.072	129.6										
2034	0.104	0.076	0.115	0.073	129.6										
2035	0.105	0.077	0.117	0.074	129.6										
2036	0.107	0.078	0.118	0.075	129.6										
2037	0.108	0.079	0.120	0.076	129.6										
2038	0.110	0.080	0.122	0.077	129.6										
2039	0.111	0.081	0.124	0.079	129.6										
2040	0.113	0.083	0.125	0.080	129.6										
Levelized															
(2008-2040)	0.091	0.067	0.097	0.065	114.9	0.004	0.003	0.006	0.003	10.4	0.005	0.004	0.008	0.003	10.3
(2009-2040)	0.091	0.067	0.098	0.065	120.0	0.003	0.003	0.005	0.002	10.7	0.005	0.004	0.008	0.003	10.7
5 years (2008-12)	0.086	0.065	0.084	0.061	56.8	0.025	0.021	0.040	0.017	60.4	0.025	0.020	0.039	0.017	26.8
10 years (2008-17)	0.084	0.063	0.084	0.060	91.2	0.012	0.010	0.020	0.008	34.2	0.013	0.011	0.021	0.009	26.9
15 years (2008-22)	0.084	0.062	0.086	0.060	102.6	0.008	0.007	0.013	0.006	22.8	0.009	0.008	0.014	0.006	18.9
PV to 2008						0.120	0.099	0.191	0.081	318.3	0.118	0.097	0.187	0.080	243.9
PV to 2009											0.120	0.099	0.191	0.081	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Su cludes June through September; Winter is all other months.

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AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.075	0.056	0.074	0.058		0.000	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.083	0.064	0.078	0.060		0.044	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.080	0.061	0.075	0.057		0.078	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.065	0.076	0.057	0.074	0.053	67	0.100	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.117	0.073	0.055	0.072	0.051	114	0.121	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.131	0.074	0.055	0.076	0.053	114	0.135	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.139	0.070	0.051	0.072	0.050	114	0.143	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.139	0.073	0.052	0.074	0.052	114	0.145	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.139	0.072	0.052	0.075	0.050	114	0.141	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.139	0.074	0.053	0.077	0.053	114	0.127	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.139	0.076	0.056	0.080	0.054	114	0.106	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.139	0.074	0.055	0.079	0.054	114	0.071	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.139	0.075	0.054	0.082	0.054	114	0.035	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.139	0.076	0.056	0.082	0.055	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.139	0.078	0.057	0.085	0.055	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.079	0.058	0.088	0.056	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.080	0.059	0.089	0.057	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.081	0.060	0.090	0.058	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.083	0.061	0.092	0.058	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.084	0.061	0.093	0.059	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.085	0.062	0.094	0.060	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.086	0.063	0.096	0.061	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.088	0.064	0.097	0.062	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.089	0.065	0.099	0.063	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.090	0.066	0.100	0.064	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.091	0.067	0.102	0.065	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.093	0.068	0.103	0.066	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.094	0.069	0.104	0.067	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.095	0.070	0.106	0.067	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.097	0.071	0.108	0.068	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.098	0.072	0.109	0.069	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.100	0.073	0.111	0.070	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.101	0.074	0.112	0.071	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.139	0.103	0.075	0.114	0.073	114		
Levelized														
(2008-2040)	0.023	0.023	0.026	0.025	24.5	18.4	0.121							
(2009-2040)	0.023	0.022	0.025	0.024	24.9	18.7	0.123							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.8	11.1	0.013							
10 years (2008-17)	0.031	0.030	0.034	0.033	20.5	15.4	0.075							
15 years (2008-22)	0.028	0.027	0.031	0.030	22.4	16.8	0.098							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	All of Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.094	0.069	0.095	0.072	-										
2008	0.105	0.078	0.097	0.074	-	0.016	0.013	0.029	0.012	-	-	-	-	-	-
2009	0.098	0.075	0.097	0.070	-	0.046	0.037	0.083	0.034	-	0.016	0.013	0.029	0.012	-
2010	0.097	0.072	0.098	0.067	60.5	0.043	0.035	0.078	0.031	72	0.046	0.037	0.083	0.034	-
2011	0.093	0.068	0.097	0.065	109.1	0.026	0.021	0.047	0.019	140	0.043	0.035	0.078	0.031	-
2012	0.094	0.070	0.098	0.068	122.1					90	0.026	0.021	0.047	0.019	140
2013	0.089	0.065	0.094	0.064	129.6					40					90
2014	0.091	0.065	0.094	0.065	129.6										40
2015	0.090	0.065	0.098	0.065	129.6										
2016	0.092	0.066	0.099	0.068	129.6										
2017	0.094	0.068	0.102	0.067	129.6										
2018	0.092	0.068	0.100	0.068	129.6										
2019	0.092	0.066	0.102	0.067	129.6										
2020	0.093	0.068	0.103	0.067	129.6										
2021	0.094	0.068	0.108	0.068	129.6										
2022	0.097	0.070	0.109	0.069	129.6										
2023	0.098	0.071	0.111	0.070	129.6										
2024	0.100	0.072	0.113	0.071	129.6										
2025	0.101	0.073	0.114	0.072	129.6										
2026	0.103	0.074	0.116	0.073	129.6										
2027	0.104	0.075	0.117	0.074	129.6										
2028	0.106	0.076	0.119	0.075	129.6										
2029	0.107	0.077	0.121	0.077	129.6										
2030	0.109	0.078	0.123	0.078	129.6										
2031	0.110	0.079	0.124	0.079	129.6										
2032	0.112	0.080	0.126	0.080	129.6										
2033	0.114	0.081	0.128	0.081	129.6										
2034	0.115	0.083	0.130	0.082	129.6										
2035	0.117	0.084	0.132	0.083	129.6										
2036	0.119	0.085	0.134	0.085	129.6										
2037	0.120	0.086	0.136	0.086	129.6										
2038	0.122	0.088	0.138	0.087	129.6										
2039	0.124	0.089	0.140	0.088	129.6										
2040	0.126	0.090	0.142	0.090	129.6										
Levelized															
(2008-2040)	0.102	0.074	0.111	0.073	114.9	0.005	0.004	0.010	0.004	13.4	0.005	0.004	0.009	0.004	10.3
(2009-2040)	0.102	0.074	0.112	0.073	120.0	0.005	0.004	0.009	0.004	14.0	0.005	0.004	0.010	0.004	10.7
5 years (2008-12)	0.098	0.073	0.098	0.069	56.8	0.026	0.021	0.048	0.019	59.0	0.026	0.021	0.047	0.019	26.8
10 years (2008-17)	0.095	0.070	0.098	0.068	91.2	0.014	0.011	0.025	0.010	35.1	0.014	0.011	0.025	0.010	26.9
15 years (2008-22)	0.094	0.069	0.100	0.068	102.6	0.010	0.008	0.018	0.007	24.6	0.010	0.008	0.017	0.007	18.9
PV to 2008						0.127	0.102	0.229	0.093	318.3	0.124	0.100	0.224	0.091	243.9
PV to 2009											0.127	0.102	0.229	0.093	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.084	0.061	0.085	0.064		0.150	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.094	0.070	0.087	0.066		0.156	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.088	0.067	0.087	0.062		0.156	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.073	0.087	0.063	0.087	0.059	67	0.167	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.131	0.083	0.060	0.086	0.058	114	0.181	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.147	0.083	0.062	0.088	0.060	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.156	0.079	0.057	0.084	0.057	114	0.191	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.156	0.081	0.057	0.084	0.058	114	0.187	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.156	0.080	0.058	0.088	0.057	114	0.176	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.156	0.082	0.059	0.088	0.060	114	0.155	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.156	0.084	0.061	0.091	0.060	114	0.127	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.156	0.083	0.061	0.090	0.061	114	0.092	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.156	0.083	0.060	0.092	0.060	114	0.049	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.156	0.084	0.062	0.094	0.061	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.156	0.086	0.062	0.098	0.062	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.088	0.063	0.099	0.063	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.089	0.064	0.101	0.064	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.091	0.065	0.102	0.065	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.092	0.066	0.104	0.066	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.093	0.067	0.105	0.067	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.095	0.068	0.107	0.068	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.096	0.069	0.108	0.069	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.098	0.070	0.110	0.070	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.099	0.071	0.112	0.071	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.100	0.072	0.113	0.072	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.102	0.073	0.115	0.073	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.103	0.074	0.116	0.074	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.105	0.075	0.118	0.075	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.106	0.076	0.120	0.076	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.108	0.077	0.122	0.077	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.109	0.078	0.123	0.078	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.111	0.080	0.125	0.079	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.113	0.081	0.127	0.080	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.114	0.082	0.129	0.081	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.136							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.139							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.015							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.085							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.110							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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	non-PSNH (reduce for PSNH)
Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	66%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	New Hampshire					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.089	0.066	0.090	0.069	-										
2008	0.099	0.075	0.092	0.070	-	0.015	0.014	0.028	0.014	-	-	-	-	-	-
2009	0.093	0.072	0.090	0.067	-	0.042	0.037	0.076	0.034	-	0.015	0.014	0.028	0.014	-
2010	0.092	0.068	0.090	0.064	60.5	0.039	0.034	0.069	0.030	72	0.042	0.037	0.076	0.034	-
2011	0.088	0.066	0.088	0.062	109.1	0.024	0.020	0.042	0.018	140	0.039	0.034	0.069	0.030	-
2012	0.089	0.067	0.093	0.064	122.1					90	0.024	0.020	0.042	0.018	140
2013	0.085	0.062	0.088	0.061	129.6					40					90
2014	0.088	0.063	0.090	0.062	129.6										40
2015	0.086	0.063	0.091	0.062	129.6										
2016	0.088	0.064	0.093	0.065	129.6										
2017	0.091	0.067	0.097	0.065	129.6										
2018	0.089	0.066	0.094	0.065	129.6										
2019	0.088	0.064	0.097	0.065	129.6										
2020	0.089	0.066	0.098	0.065	129.6										
2021	0.090	0.067	0.100	0.065	129.6										
2022	0.092	0.068	0.103	0.066	129.6										
2023	0.094	0.069	0.105	0.067	129.6										
2024	0.095	0.070	0.106	0.068	129.6										
2025	0.096	0.071	0.108	0.069	129.6										
2026	0.098	0.072	0.110	0.070	129.6										
2027	0.099	0.073	0.111	0.071	129.6										
2028	0.100	0.074	0.113	0.072	129.6										
2029	0.102	0.075	0.114	0.073	129.6										
2030	0.103	0.076	0.116	0.074	129.6										
2031	0.105	0.077	0.118	0.075	129.6										
2032	0.106	0.078	0.119	0.076	129.6										
2033	0.108	0.080	0.121	0.078	129.6										
2034	0.110	0.081	0.123	0.079	129.6										
2035	0.111	0.082	0.125	0.080	129.6										
2036	0.113	0.083	0.126	0.081	129.6										
2037	0.114	0.084	0.128	0.082	129.6										
2038	0.116	0.086	0.130	0.083	129.6										
2039	0.118	0.087	0.132	0.085	129.6										
2040	0.119	0.088	0.134	0.086	129.6										
Levelized (2008-2040)	0.097	0.072	0.104	0.070	114.9	0.004	0.003	0.007	0.003	10.4	0.005	0.004	0.009	0.004	10.3
(2009-2040)	0.097	0.071	0.105	0.070	120.0	0.003	0.003	0.006	0.003	10.7	0.005	0.004	0.009	0.004	10.7
5 years (2008-12)	0.092	0.070	0.090	0.065	56.8	0.024	0.021	0.043	0.019	60.4	0.024	0.021	0.042	0.019	26.8
10 years (2008-17)	0.090	0.067	0.091	0.064	91.2	0.012	0.011	0.022	0.010	34.2	0.013	0.011	0.022	0.010	26.9
15 years (2008-22)	0.090	0.067	0.093	0.065	102.6	0.008	0.007	0.014	0.006	22.8	0.009	0.008	0.016	0.007	18.9
PV to 2008						0.116	0.102	0.208	0.093	318.3	0.114	0.099	0.203	0.091	243.9
PV to 2009											0.116	0.102	0.208	0.093	249.3

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.081	0.060	0.081	0.063		0.000	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.090	0.068	0.084	0.064		0.000	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.085	0.066	0.081	0.060		0.019	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.067	0.083	0.062	0.081	0.058	67	0.035	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.122	0.079	0.059	0.080	0.056	114	0.063	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.136	0.080	0.060	0.083	0.057	114	0.085	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.144	0.076	0.055	0.079	0.054	114	0.100	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.144	0.078	0.056	0.081	0.056	114	0.110	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.144	0.077	0.056	0.082	0.055	114	0.111	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.144	0.079	0.057	0.084	0.058	114	0.103	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.144	0.082	0.060	0.087	0.058	114	0.088	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.144	0.080	0.059	0.085	0.059	114	0.066	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.144	0.080	0.058	0.088	0.058	114	0.036	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.144	0.081	0.060	0.089	0.059	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.144	0.082	0.061	0.091	0.059	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.084	0.062	0.094	0.060	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.085	0.063	0.095	0.061	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.086	0.064	0.097	0.062	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.087	0.065	0.098	0.063	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.089	0.065	0.100	0.064	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.090	0.066	0.101	0.065	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.091	0.067	0.102	0.066	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.093	0.068	0.104	0.067	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.094	0.069	0.105	0.068	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.095	0.070	0.107	0.069	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.097	0.071	0.109	0.070	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.098	0.072	0.110	0.071	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.100	0.073	0.112	0.072	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.101	0.074	0.113	0.073	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.103	0.076	0.115	0.074	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.104	0.077	0.117	0.075	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.105	0.078	0.118	0.076	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.107	0.079	0.120	0.077	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.144	0.109	0.080	0.122	0.078	114		
Levelized														
(2008-2040)	0.023	0.023	0.026	0.025	24.5	18.4	0.126							
(2009-2040)	0.023	0.022	0.025	0.024	24.9	18.7	0.128							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.8	11.1	0.014							
10 years (2008-17)	0.031	0.030	0.034	0.033	20.5	15.4	0.078							
15 years (2008-22)	0.028	0.027	0.031	0.030	22.4	16.8	0.102							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Rhode Island					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.092	0.067	0.093	0.070	-										
2008	0.105	0.077	0.096	0.072	-	0.015	0.012	0.024	0.010	-	-	-	-	-	-
2009	0.096	0.074	0.097	0.067	-	0.043	0.035	0.070	0.031	-	0.015	0.012	0.024	0.010	-
2010	0.096	0.071	0.097	0.065	60.5	0.040	0.033	0.066	0.030	72	0.043	0.035	0.070	0.031	-
2011	0.092	0.067	0.095	0.063	109.1	0.025	0.020	0.040	0.018	140	0.040	0.033	0.066	0.030	-
2012	0.093	0.069	0.095	0.065	122.1					90	0.025	0.020	0.040	0.018	140
2013	0.087	0.064	0.092	0.063	129.6					40					90
2014	0.090	0.064	0.092	0.063	129.6										40
2015	0.089	0.064	0.096	0.062	129.6										
2016	0.090	0.066	0.098	0.066	129.6										
2017	0.093	0.068	0.101	0.066	129.6										
2018	0.092	0.067	0.098	0.067	129.6										
2019	0.092	0.066	0.101	0.067	129.6										
2020	0.092	0.068	0.102	0.068	129.6										
2021	0.093	0.069	0.106	0.067	129.6										
2022	0.098	0.069	0.108	0.070	129.6										
2023	0.099	0.070	0.109	0.071	129.6										
2024	0.100	0.071	0.111	0.072	129.6										
2025	0.102	0.072	0.113	0.073	129.6										
2026	0.103	0.073	0.114	0.074	129.6										
2027	0.105	0.074	0.116	0.075	129.6										
2028	0.106	0.075	0.118	0.076	129.6										
2029	0.108	0.076	0.119	0.077	129.6										
2030	0.109	0.077	0.121	0.078	129.6										
2031	0.111	0.079	0.123	0.080	129.6										
2032	0.113	0.080	0.125	0.081	129.6										
2033	0.114	0.081	0.126	0.082	129.6										
2034	0.116	0.082	0.128	0.083	129.6										
2035	0.118	0.083	0.130	0.084	129.6										
2036	0.119	0.084	0.132	0.085	129.6										
2037	0.121	0.086	0.134	0.087	129.6										
2038	0.123	0.087	0.136	0.088	129.6										
2039	0.125	0.088	0.138	0.089	129.6										
2040	0.126	0.089	0.140	0.091	129.6										
Levelized															
(2008-2040)	0.101	0.073	0.109	0.072	114.9	0.005	0.004	0.008	0.004	13.4	0.005	0.004	0.008	0.004	10.3
(2009-2040)	0.101	0.073	0.110	0.072	120.0	0.005	0.004	0.007	0.003	14.0	0.005	0.004	0.008	0.004	10.7
5 years (2008-12)	0.096	0.072	0.096	0.067	56.8	0.025	0.020	0.040	0.018	59.0	0.024	0.020	0.040	0.018	26.8
10 years (2008-17)	0.093	0.068	0.096	0.065	91.2	0.013	0.011	0.021	0.010	35.1	0.013	0.010	0.021	0.009	26.9
15 years (2008-22)	0.093	0.068	0.098	0.066	102.6	0.009	0.007	0.015	0.007	24.6	0.009	0.007	0.015	0.007	18.9
PV to 2008						0.118	0.095	0.194	0.087	318.3	0.115	0.093	0.189	0.085	243.9
PV to 2009											0.118	0.095	0.194	0.087	249.3

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.083	0.061	0.084	0.063		0.050	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.095	0.069	0.087	0.065		0.067	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.087	0.066	0.088	0.060		0.078	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.073	0.086	0.064	0.087	0.058	67	0.083	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.132	0.082	0.060	0.085	0.056	114	0.106	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.147	0.083	0.061	0.085	0.058	114	0.122	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.156	0.078	0.057	0.082	0.056	114	0.131	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.156	0.081	0.057	0.083	0.056	114	0.135	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.156	0.079	0.057	0.086	0.055	114	0.141	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.156	0.081	0.059	0.087	0.058	114	0.134	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.156	0.084	0.061	0.090	0.059	114	0.116	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.156	0.083	0.060	0.088	0.060	114	0.088	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.156	0.083	0.060	0.091	0.060	114	0.049	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.156	0.083	0.062	0.093	0.061	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.156	0.084	0.063	0.096	0.061	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.089	0.063	0.098	0.064	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.090	0.064	0.099	0.064	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.091	0.065	0.101	0.065	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.093	0.065	0.102	0.066	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.094	0.066	0.104	0.067	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.095	0.067	0.105	0.068	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.097	0.068	0.107	0.069	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.098	0.069	0.108	0.070	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.100	0.070	0.110	0.071	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.101	0.071	0.112	0.072	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.102	0.072	0.113	0.073	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.104	0.073	0.115	0.074	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.105	0.075	0.117	0.076	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.107	0.076	0.118	0.077	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.109	0.077	0.120	0.078	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.110	0.078	0.122	0.079	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.112	0.079	0.123	0.080	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.113	0.080	0.125	0.081	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.115	0.081	0.127	0.082	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.136							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.139							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.015							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.085							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.110							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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	PSB risk adder
Retail Adder	11%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	66%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Vermont					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.096	0.071	0.097	0.073	-										
2008	0.106	0.080	0.099	0.076	-	0.015	0.012	0.025	0.010	-	-	-	-	-	-
2009	0.100	0.077	0.100	0.070	-	0.042	0.034	0.071	0.029	-	0.015	0.012	0.025	0.010	-
2010	0.099	0.074	0.099	0.070	61.1	0.039	0.031	0.067	0.027	72	0.042	0.034	0.071	0.029	-
2011	0.094	0.070	0.097	0.066	110.2	0.024	0.019	0.041	0.016	140	0.039	0.031	0.067	0.027	-
2012	0.095	0.070	0.099	0.069	123.3					90	0.024	0.019	0.041	0.016	140
2013	0.091	0.066	0.098	0.066	130.9					40					90
2014	0.093	0.066	0.097	0.066	130.9										40
2015	0.092	0.066	0.098	0.067	130.9										
2016	0.093	0.068	0.100	0.070	130.9										
2017	0.097	0.070	0.102	0.069	130.9										
2018	0.094	0.068	0.101	0.070	130.9										
2019	0.092	0.066	0.102	0.069	130.9										
2020	0.095	0.069	0.104	0.069	130.9										
2021	0.098	0.069	0.107	0.069	130.9										
2022	0.100	0.071	0.109	0.071	130.9										
2023	0.101	0.072	0.111	0.072	130.9										
2024	0.102	0.073	0.112	0.073	130.9										
2025	0.104	0.074	0.114	0.074	130.9										
2026	0.105	0.075	0.116	0.075	130.9										
2027	0.107	0.076	0.117	0.076	130.9										
2028	0.109	0.077	0.119	0.077	130.9										
2029	0.110	0.078	0.121	0.078	130.9										
2030	0.112	0.079	0.122	0.079	130.9										
2031	0.113	0.080	0.124	0.080	130.9										
2032	0.115	0.081	0.126	0.082	130.9										
2033	0.117	0.083	0.128	0.083	130.9										
2034	0.118	0.084	0.130	0.084	130.9										
2035	0.120	0.085	0.132	0.085	130.9										
2036	0.122	0.086	0.133	0.086	130.9										
2037	0.124	0.088	0.135	0.088	130.9										
2038	0.125	0.089	0.137	0.089	130.9										
2039	0.127	0.090	0.139	0.090	130.9										
2040	0.129	0.091	0.141	0.092	130.9										
Levelized															
(2008-2040)	0.104	0.075	0.111	0.074	116.1	0.004	0.003	0.006	0.002	10.4	0.005	0.004	0.008	0.003	10.3
(2009-2040)	0.104	0.075	0.112	0.074	121.2	0.003	0.003	0.006	0.002	10.7	0.005	0.004	0.008	0.003	10.7
5 years (2008-12)	0.099	0.074	0.099	0.070	57.4	0.024	0.019	0.041	0.016	60.4	0.024	0.019	0.040	0.016	26.8
10 years (2008-17)	0.096	0.071	0.099	0.069	92.1	0.012	0.010	0.020	0.008	34.2	0.012	0.010	0.021	0.008	26.9
15 years (2008-22)	0.096	0.070	0.101	0.069	103.7	0.008	0.006	0.014	0.005	22.8	0.009	0.007	0.015	0.006	18.9
PV to 2008						0.116	0.092	0.196	0.078	318.3	0.113	0.090	0.192	0.077	243.9
PV to 2009											0.116	0.092	0.196	0.078	249.3

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.086	0.063	0.087	0.065		0.062	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.094	0.071	0.088	0.067		0.111	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.088	0.068	0.089	0.062		0.140	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.068	0.088	0.065	0.087	0.061	67	0.152	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.123	0.083	0.061	0.086	0.058	114	0.159	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.138	0.084	0.062	0.087	0.060	114	0.172	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.147	0.080	0.057	0.086	0.058	114	0.180	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.147	0.082	0.058	0.086	0.058	114	0.176	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.147	0.081	0.058	0.087	0.058	114	0.176	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.147	0.082	0.060	0.089	0.061	114	0.141	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.147	0.086	0.062	0.091	0.061	114	0.106	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.147	0.084	0.061	0.090	0.062	114	0.071	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.147	0.083	0.059	0.091	0.062	114	0.035	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.147	0.085	0.062	0.094	0.062	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.147	0.088	0.062	0.097	0.062	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.090	0.063	0.098	0.064	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.091	0.064	0.100	0.064	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.092	0.065	0.101	0.065	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.094	0.066	0.103	0.066	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.095	0.067	0.104	0.067	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.096	0.068	0.105	0.068	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.098	0.069	0.107	0.069	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.099	0.070	0.109	0.070	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.101	0.071	0.110	0.071	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.102	0.072	0.112	0.072	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.104	0.073	0.113	0.073	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.105	0.074	0.115	0.074	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.107	0.075	0.117	0.076	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.108	0.077	0.118	0.077	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.110	0.078	0.120	0.078	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.111	0.079	0.122	0.079	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.113	0.080	0.124	0.080	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.114	0.081	0.125	0.081	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.147	0.116	0.082	0.127	0.082	114		
Levelized														
(2008-2040)	0.023	0.023	0.026	0.025	24.5	18.4	0.128							
(2009-2040)	0.023	0.022	0.025	0.024	24.9	18.7	0.130							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.8	11.1	0.014							
10 years (2008-17)	0.031	0.030	0.034	0.033	20.5	15.4	0.079							
15 years (2008-22)	0.028	0.027	0.031	0.030	22.4	16.8	0.103							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	64%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Northeast Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.094	0.069	0.096	0.072	-										
2008	0.105	0.078	0.098	0.075	-	0.015	0.013	0.029	0.013	-	-	-	-	-	-
2009	0.099	0.075	0.099	0.071	-	0.044	0.038	0.084	0.037	-	0.015	0.013	0.029	0.013	-
2010	0.098	0.071	0.099	0.068	60.5	0.041	0.035	0.078	0.034	72	0.044	0.038	0.084	0.037	-
2011	0.094	0.068	0.098	0.066	109.1	0.025	0.021	0.048	0.021	140	0.041	0.035	0.078	0.034	-
2012	0.095	0.070	0.100	0.070	122.1					90	0.025	0.021	0.048	0.021	140
2013	0.089	0.065	0.096	0.065	129.6					40					90
2014	0.092	0.065	0.096	0.065	129.6										40
2015	0.090	0.066	0.100	0.065	129.6										
2016	0.093	0.066	0.101	0.069	129.6										
2017	0.095	0.068	0.103	0.067	129.6										
2018	0.093	0.068	0.102	0.069	129.6										
2019	0.093	0.067	0.103	0.067	129.6										
2020	0.094	0.068	0.104	0.067	129.6										
2021	0.095	0.069	0.109	0.068	129.6										
2022	0.098	0.070	0.111	0.069	129.6										
2023	0.099	0.071	0.112	0.070	129.6										
2024	0.101	0.072	0.114	0.071	129.6										
2025	0.102	0.073	0.115	0.072	129.6										
2026	0.104	0.074	0.117	0.073	129.6										
2027	0.105	0.075	0.119	0.074	129.6										
2028	0.107	0.076	0.121	0.075	129.6										
2029	0.108	0.077	0.122	0.077	129.6										
2030	0.110	0.078	0.124	0.078	129.6										
2031	0.111	0.080	0.126	0.079	129.6										
2032	0.113	0.081	0.128	0.080	129.6										
2033	0.115	0.082	0.130	0.081	129.6										
2034	0.116	0.083	0.131	0.082	129.6										
2035	0.118	0.084	0.133	0.083	129.6										
2036	0.120	0.086	0.135	0.085	129.6										
2037	0.122	0.087	0.137	0.086	129.6										
2038	0.123	0.088	0.139	0.087	129.6										
2039	0.125	0.089	0.141	0.088	129.6										
2040	0.127	0.091	0.143	0.090	129.6										
Levelized															
(2008-2040)	0.103	0.074	0.112	0.073	114.9	0.004	0.003	0.007	0.003	10.4	0.005	0.004	0.009	0.004	10.3
(2009-2040)	0.103	0.074	0.113	0.073	120.0	0.003	0.003	0.007	0.003	10.7	0.005	0.004	0.010	0.004	10.7
5 years (2008-12)	0.098	0.073	0.099	0.070	56.8	0.025	0.022	0.048	0.021	60.4	0.025	0.021	0.047	0.020	26.8
10 years (2008-17)	0.095	0.070	0.099	0.068	91.2	0.012	0.011	0.024	0.010	34.2	0.013	0.011	0.025	0.011	26.9
15 years (2008-22)	0.095	0.069	0.101	0.068	102.6	0.008	0.007	0.016	0.007	22.8	0.009	0.008	0.017	0.008	18.9
PV to 2008						0.121	0.104	0.230	0.100	318.3	0.118	0.102	0.225	0.098	243.9
PV to 2009											0.121	0.104	0.230	0.100	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.084	0.061	0.086	0.064		0.150	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.094	0.069	0.088	0.066		0.156	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.088	0.067	0.088	0.063		0.156	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.069	0.088	0.063	0.088	0.060	67	0.167	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.125	0.084	0.060	0.087	0.059	114	0.181	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.140	0.084	0.062	0.089	0.062	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.148	0.079	0.057	0.086	0.057	114	0.191	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.148	0.081	0.058	0.085	0.058	114	0.187	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.148	0.080	0.058	0.089	0.057	114	0.176	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.148	0.083	0.059	0.090	0.061	114	0.155	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.148	0.085	0.061	0.092	0.060	114	0.127	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.148	0.084	0.061	0.092	0.062	114	0.092	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.148	0.084	0.060	0.094	0.061	114	0.049	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.148	0.085	0.062	0.095	0.061	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.148	0.087	0.063	0.099	0.062	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.089	0.064	0.101	0.063	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.090	0.065	0.102	0.064	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.092	0.065	0.103	0.065	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.093	0.066	0.105	0.066	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.094	0.067	0.107	0.067	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.096	0.068	0.108	0.068	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.097	0.069	0.110	0.069	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.098	0.070	0.111	0.070	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.100	0.071	0.113	0.071	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.101	0.072	0.114	0.072	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.103	0.073	0.116	0.073	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.104	0.074	0.118	0.074	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.106	0.076	0.120	0.075	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.107	0.077	0.121	0.076	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.109	0.078	0.123	0.077	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.110	0.079	0.125	0.078	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.112	0.080	0.127	0.079	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.114	0.081	0.128	0.080	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.148	0.115	0.082	0.130	0.082	114		
Levelized														
(2008-2040)	0.023	0.023	0.026	0.025	24.5	18.4	0.129							
(2009-2040)	0.023	0.022	0.025	0.024	24.9	18.7	0.132							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.8	11.1	0.014							
10 years (2008-17)	0.031	0.030	0.034	0.033	20.5	15.4	0.081							
15 years (2008-22)	0.028	0.027	0.031	0.030	22.4	16.8	0.105							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	57%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Southeast Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.093	0.068	0.094	0.070	-										
2008	0.105	0.078	0.096	0.072	-	0.018	0.014	0.031	0.013	-	-	-	-	-	-
2009	0.097	0.074	0.096	0.067	-	0.052	0.041	0.090	0.037	-	0.018	0.014	0.031	0.013	-
2010	0.096	0.071	0.097	0.066	60.5	0.048	0.038	0.084	0.034	72	0.052	0.041	0.090	0.037	-
2011	0.091	0.067	0.094	0.063	109.1	0.030	0.023	0.051	0.021	140	0.048	0.038	0.084	0.034	-
2012	0.092	0.069	0.096	0.066	122.1					90	0.030	0.023	0.051	0.021	140
2013	0.087	0.064	0.092	0.063	129.6					40					90
2014	0.090	0.064	0.093	0.064	129.6										40
2015	0.089	0.064	0.096	0.063	129.6										
2016	0.090	0.066	0.097	0.065	129.6										
2017	0.093	0.067	0.100	0.066	129.6										
2018	0.091	0.067	0.099	0.066	129.6										
2019	0.090	0.065	0.102	0.065	129.6										
2020	0.091	0.067	0.102	0.066	129.6										
2021	0.093	0.068	0.107	0.067	129.6										
2022	0.096	0.068	0.108	0.069	129.6										
2023	0.098	0.069	0.110	0.070	129.6										
2024	0.099	0.070	0.112	0.071	129.6										
2025	0.101	0.071	0.113	0.072	129.6										
2026	0.102	0.072	0.115	0.073	129.6										
2027	0.104	0.073	0.116	0.074	129.6										
2028	0.105	0.075	0.118	0.075	129.6										
2029	0.107	0.076	0.120	0.076	129.6										
2030	0.108	0.077	0.122	0.077	129.6										
2031	0.110	0.078	0.123	0.078	129.6										
2032	0.111	0.079	0.125	0.079	129.6										
2033	0.113	0.080	0.127	0.080	129.6										
2034	0.115	0.081	0.129	0.082	129.6										
2035	0.116	0.082	0.131	0.083	129.6										
2036	0.118	0.084	0.133	0.084	129.6										
2037	0.120	0.085	0.135	0.085	129.6										
2038	0.121	0.086	0.136	0.086	129.6										
2039	0.123	0.087	0.138	0.088	129.6										
2040	0.125	0.089	0.140	0.089	129.6										
Levelized															
(2008-2040)	0.101	0.073	0.110	0.072	114.9	0.006	0.005	0.010	0.004	13.4	0.006	0.005	0.010	0.004	10.3
(2009-2040)	0.100	0.072	0.110	0.071	120.0	0.006	0.004	0.009	0.004	14.0	0.006	0.005	0.011	0.004	10.7
5 years (2008-12)	0.096	0.072	0.096	0.067	56.8	0.030	0.023	0.052	0.021	59.0	0.029	0.023	0.050	0.020	26.8
10 years (2008-17)	0.093	0.069	0.096	0.066	91.2	0.016	0.012	0.027	0.011	35.1	0.015	0.012	0.027	0.011	26.9
15 years (2008-22)	0.093	0.068	0.098	0.066	102.6	0.011	0.009	0.019	0.008	24.6	0.011	0.008	0.019	0.008	18.9
PV to 2008						0.143	0.112	0.247	0.100	318.3	0.140	0.109	0.241	0.098	243.9
PV to 2009											0.143	0.112	0.247	0.100	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Su cludes June through September; Winter is all other months.

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AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.083	0.061	0.084	0.062		0.150	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.094	0.069	0.086	0.064		0.156	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.087	0.066	0.086	0.060		0.156	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.078	0.086	0.063	0.086	0.058	67	0.167	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.140	0.081	0.059	0.084	0.056	114	0.181	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.157	0.082	0.061	0.085	0.058	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.167	0.077	0.056	0.081	0.055	114	0.191	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.167	0.080	0.056	0.082	0.056	114	0.187	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.167	0.079	0.057	0.086	0.055	114	0.176	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.167	0.080	0.058	0.087	0.058	114	0.155	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.167	0.083	0.060	0.090	0.059	114	0.127	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.167	0.082	0.060	0.089	0.059	114	0.092	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.167	0.082	0.059	0.092	0.059	114	0.049	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.167	0.083	0.061	0.092	0.060	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.167	0.084	0.061	0.097	0.061	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.088	0.062	0.099	0.062	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.089	0.063	0.100	0.063	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.090	0.064	0.101	0.064	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.091	0.065	0.103	0.065	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.093	0.066	0.104	0.066	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.094	0.067	0.106	0.067	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.096	0.068	0.107	0.068	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.097	0.069	0.109	0.069	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.098	0.070	0.111	0.070	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.100	0.071	0.112	0.071	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.101	0.072	0.114	0.072	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.103	0.073	0.115	0.073	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.104	0.074	0.117	0.074	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.106	0.075	0.119	0.075	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.107	0.076	0.121	0.076	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.109	0.077	0.122	0.077	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.110	0.078	0.124	0.079	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.112	0.079	0.126	0.080	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.167	0.114	0.081	0.128	0.081	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.145							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.148							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.016							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.090							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.117							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	West-Central Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.095	0.070	0.096	0.073	-										
2008	0.106	0.080	0.098	0.076	-	0.015	0.012	0.026	0.010	-	-	-	-	-	-
2009	0.098	0.076	0.097	0.072	-	0.045	0.034	0.076	0.029	-	0.015	0.012	0.026	0.010	-
2010	0.097	0.073	0.097	0.068	60.5	0.042	0.032	0.071	0.027	72	0.045	0.034	0.076	0.029	-
2011	0.093	0.070	0.096	0.066	109.1	0.025	0.019	0.043	0.016	140	0.042	0.032	0.071	0.027	-
2012	0.093	0.071	0.098	0.069	122.1					90	0.025	0.019	0.043	0.016	140
2013	0.089	0.066	0.094	0.065	129.6					40					90
2014	0.092	0.066	0.094	0.066	129.6										40
2015	0.090	0.066	0.098	0.066	129.6										
2016	0.092	0.067	0.098	0.069	129.6										
2017	0.094	0.069	0.101	0.069	129.6										
2018	0.091	0.068	0.099	0.068	129.6										
2019	0.091	0.066	0.101	0.067	129.6										
2020	0.093	0.069	0.103	0.068	129.6										
2021	0.093	0.069	0.106	0.068	129.6										
2022	0.096	0.070	0.108	0.070	129.6										
2023	0.098	0.071	0.110	0.071	129.6										
2024	0.099	0.072	0.112	0.072	129.6										
2025	0.101	0.073	0.113	0.073	129.6										
2026	0.102	0.074	0.115	0.074	129.6										
2027	0.103	0.075	0.116	0.075	129.6										
2028	0.105	0.076	0.118	0.076	129.6										
2029	0.106	0.078	0.120	0.077	129.6										
2030	0.108	0.079	0.122	0.078	129.6										
2031	0.110	0.080	0.123	0.079	129.6										
2032	0.111	0.081	0.125	0.081	129.6										
2033	0.113	0.082	0.127	0.082	129.6										
2034	0.114	0.083	0.129	0.083	129.6										
2035	0.116	0.085	0.131	0.084	129.6										
2036	0.118	0.086	0.133	0.085	129.6										
2037	0.119	0.087	0.134	0.087	129.6										
2038	0.121	0.088	0.136	0.088	129.6										
2039	0.123	0.090	0.138	0.089	129.6										
2040	0.125	0.091	0.140	0.090	129.6										
Levelized															
(2008-2040)	0.101	0.074	0.110	0.074	114.9	0.005	0.004	0.009	0.003	13.4	0.005	0.004	0.009	0.003	10.3
(2009-2040)	0.101	0.074	0.111	0.073	120.0	0.005	0.004	0.008	0.003	14.0	0.005	0.004	0.009	0.003	10.7
5 years (2008-12)	0.098	0.074	0.097	0.070	56.8	0.026	0.020	0.044	0.016	59.0	0.025	0.019	0.043	0.016	26.8
10 years (2008-17)	0.095	0.071	0.097	0.069	91.2	0.013	0.010	0.023	0.009	35.1	0.013	0.010	0.023	0.008	26.9
15 years (2008-22)	0.094	0.070	0.099	0.069	102.6	0.009	0.007	0.016	0.006	24.6	0.009	0.007	0.016	0.006	18.9
PV to 2008						0.122	0.093	0.209	0.078	318.3	0.120	0.091	0.204	0.076	243.9
PV to 2009											0.122	0.093	0.209	0.078	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.085	0.062	0.086	0.065		0.150	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.095	0.071	0.087	0.067		0.156	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.087	0.068	0.086	0.064		0.156	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.074	0.087	0.064	0.087	0.060	67	0.167	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.133	0.083	0.062	0.086	0.058	114	0.181	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.149	0.083	0.063	0.087	0.061	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.158	0.079	0.058	0.083	0.057	114	0.191	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.158	0.082	0.058	0.084	0.059	114	0.187	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.158	0.080	0.058	0.087	0.058	114	0.176	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.158	0.082	0.060	0.087	0.061	114	0.155	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.158	0.084	0.062	0.091	0.061	114	0.127	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.158	0.082	0.061	0.089	0.061	114	0.092	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.158	0.082	0.060	0.091	0.060	114	0.049	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.158	0.085	0.062	0.093	0.062	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.158	0.085	0.062	0.097	0.062	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.088	0.064	0.098	0.063	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.089	0.065	0.100	0.064	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.090	0.066	0.101	0.065	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.091	0.067	0.103	0.066	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.093	0.067	0.104	0.067	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.094	0.068	0.106	0.068	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.095	0.069	0.107	0.069	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.097	0.070	0.109	0.070	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.098	0.071	0.111	0.071	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.100	0.073	0.112	0.072	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.101	0.074	0.114	0.073	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.103	0.075	0.115	0.074	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.104	0.076	0.117	0.075	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.106	0.077	0.119	0.076	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.107	0.078	0.120	0.078	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.109	0.079	0.122	0.079	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.110	0.080	0.124	0.080	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.112	0.081	0.126	0.081	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.113	0.083	0.128	0.082	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.138							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.140							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.015							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.086							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.111							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	59%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Massachusetts outside of Northeast Mass					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.094	0.069	0.095	0.072	-										
2008	0.105	0.079	0.097	0.074	-	0.017	0.013	0.028	0.011	-	-	-	-	-	-
2009	0.097	0.075	0.096	0.070	-	0.048	0.037	0.083	0.032	-	0.017	0.013	0.028	0.011	-
2010	0.097	0.072	0.097	0.067	60.5	0.045	0.034	0.077	0.030	72	0.048	0.037	0.083	0.032	-
2011	0.092	0.069	0.095	0.065	109.1	0.027	0.021	0.047	0.018	140	0.045	0.034	0.077	0.030	-
2012	0.093	0.070	0.097	0.067	122.1					90	0.027	0.021	0.047	0.018	140
2013	0.088	0.065	0.093	0.064	129.6					40					90
2014	0.091	0.065	0.093	0.065	129.6										40
2015	0.089	0.065	0.097	0.064	129.6										
2016	0.091	0.066	0.097	0.067	129.6										
2017	0.093	0.068	0.101	0.067	129.6										
2018	0.091	0.067	0.099	0.067	129.6										
2019	0.091	0.066	0.101	0.066	129.6										
2020	0.092	0.068	0.102	0.067	129.6										
2021	0.093	0.068	0.107	0.067	129.6										
2022	0.096	0.069	0.108	0.069	129.6										
2023	0.098	0.070	0.110	0.070	129.6										
2024	0.099	0.071	0.112	0.071	129.6										
2025	0.101	0.072	0.113	0.072	129.6										
2026	0.102	0.073	0.115	0.073	129.6										
2027	0.104	0.074	0.116	0.074	129.6										
2028	0.105	0.075	0.118	0.075	129.6										
2029	0.107	0.077	0.120	0.076	129.6										
2030	0.108	0.078	0.122	0.078	129.6										
2031	0.110	0.079	0.123	0.079	129.6										
2032	0.111	0.080	0.125	0.080	129.6										
2033	0.113	0.081	0.127	0.081	129.6										
2034	0.114	0.082	0.129	0.082	129.6										
2035	0.116	0.083	0.131	0.083	129.6										
2036	0.118	0.085	0.133	0.085	129.6										
2037	0.120	0.086	0.134	0.086	129.6										
2038	0.121	0.087	0.136	0.087	129.6										
2039	0.123	0.088	0.138	0.088	129.6										
2040	0.125	0.090	0.140	0.090	129.6										
Levelized															
(2008-2040)	0.101	0.074	0.110	0.073	114.9	0.006	0.004	0.010	0.004	13.4	0.005	0.004	0.009	0.004	10.3
(2009-2040)	0.101	0.073	0.110	0.072	120.0	0.005	0.004	0.009	0.003	14.0	0.006	0.004	0.010	0.004	10.7
5 years (2008-12)	0.097	0.073	0.097	0.069	56.8	0.028	0.021	0.047	0.018	59.0	0.027	0.021	0.046	0.018	26.8
10 years (2008-17)	0.094	0.070	0.096	0.067	91.2	0.015	0.011	0.025	0.010	35.1	0.014	0.011	0.024	0.009	26.9
15 years (2008-22)	0.093	0.069	0.098	0.067	102.6	0.010	0.008	0.018	0.007	24.6	0.010	0.008	0.017	0.007	18.9
PV to 2008						0.132	0.101	0.227	0.087	318.3	0.129	0.099	0.222	0.086	243.9
PV to 2009											0.132	0.101	0.227	0.087	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.084	0.061	0.085	0.064		0.150	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.094	0.070	0.086	0.066		0.156	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.087	0.067	0.086	0.062		0.156	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.076	0.086	0.064	0.087	0.059	67	0.167	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.136	0.082	0.060	0.085	0.057	114	0.181	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.153	0.083	0.062	0.086	0.059	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.162	0.078	0.057	0.082	0.056	114	0.191	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.162	0.081	0.057	0.083	0.057	114	0.187	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.162	0.079	0.058	0.087	0.057	114	0.176	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.162	0.081	0.059	0.087	0.059	114	0.155	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.162	0.084	0.061	0.090	0.060	114	0.127	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.162	0.082	0.060	0.089	0.060	114	0.092	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.162	0.082	0.059	0.092	0.059	114	0.049	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.162	0.084	0.062	0.093	0.061	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.162	0.085	0.062	0.097	0.061	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.088	0.063	0.099	0.063	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.089	0.064	0.100	0.064	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.090	0.065	0.101	0.065	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.091	0.066	0.103	0.066	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.093	0.067	0.104	0.067	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.094	0.068	0.106	0.068	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.095	0.069	0.107	0.069	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.097	0.070	0.109	0.070	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.098	0.071	0.111	0.071	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.100	0.072	0.112	0.072	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.101	0.073	0.114	0.073	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.103	0.074	0.115	0.074	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.104	0.075	0.117	0.075	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.106	0.076	0.119	0.076	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.107	0.077	0.121	0.077	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.109	0.078	0.122	0.078	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.110	0.079	0.124	0.079	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.112	0.080	0.126	0.080	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.162	0.113	0.082	0.128	0.081	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.141							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.144							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.016							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.088							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.114							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Southwest Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.100	0.073	0.105	0.076	-										
2008	0.112	0.083	0.107	0.081	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.105	0.080	0.108	0.074	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.102	0.076	0.105	0.072	60.5	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.097	0.071	0.104	0.069	109.1	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.098	0.073	0.108	0.070	122.1					90	0.028	0.023	0.059	0.030	140
2013	0.094	0.067	0.101	0.066	129.6					40					90
2014	0.095	0.067	0.100	0.067	129.6										40
2015	0.093	0.067	0.100	0.066	129.6										
2016	0.094	0.068	0.103	0.067	129.6										
2017	0.098	0.070	0.107	0.070	129.6										
2018	0.096	0.071	0.105	0.070	129.6										
2019	0.095	0.069	0.105	0.069	129.6										
2020	0.097	0.071	0.109	0.070	129.6										
2021	0.097	0.072	0.111	0.070	129.6										
2022	0.100	0.072	0.114	0.072	129.6										
2023	0.102	0.073	0.116	0.073	129.6										
2024	0.103	0.074	0.118	0.074	129.6										
2025	0.105	0.075	0.119	0.075	129.6										
2026	0.106	0.076	0.121	0.076	129.6										
2027	0.108	0.077	0.123	0.077	129.6										
2028	0.110	0.079	0.125	0.078	129.6										
2029	0.111	0.080	0.127	0.079	129.6										
2030	0.113	0.081	0.128	0.081	129.6										
2031	0.114	0.082	0.130	0.082	129.6										
2032	0.116	0.083	0.132	0.083	129.6										
2033	0.118	0.084	0.134	0.084	129.6										
2034	0.119	0.086	0.136	0.085	129.6										
2035	0.121	0.087	0.138	0.087	129.6										
2036	0.123	0.088	0.140	0.088	129.6										
2037	0.125	0.089	0.142	0.089	129.6										
2038	0.126	0.091	0.144	0.090	129.6										
2039	0.128	0.092	0.146	0.092	129.6										
2040	0.130	0.093	0.148	0.093	129.6										
Levelized															
(2008-2040)	0.106	0.077	0.117	0.076	114.9	0.004	0.003	0.009	0.004	10.4	0.006	0.004	0.012	0.006	10.3
(2009-2040)	0.105	0.076	0.117	0.075	120.0	0.004	0.003	0.008	0.004	10.7	0.006	0.005	0.012	0.006	10.7
5 years (2008-12)	0.103	0.077	0.106	0.073	56.8	0.028	0.023	0.058	0.029	60.4	0.028	0.022	0.057	0.029	26.8
10 years (2008-17)	0.099	0.073	0.104	0.070	91.2	0.014	0.011	0.029	0.015	34.2	0.015	0.012	0.030	0.015	26.9
15 years (2008-22)	0.098	0.072	0.106	0.070	102.6	0.009	0.008	0.019	0.010	22.8	0.010	0.008	0.021	0.011	18.9
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9
PV to 2009											0.135	0.109	0.279	0.141	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.089	0.065	0.094	0.068		0.175	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.099	0.073	0.095	0.071		0.222	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.093	0.070	0.096	0.065		0.233	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.074	0.090	0.067	0.093	0.063	67	0.233	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.133	0.087	0.063	0.092	0.061	114	0.211	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.148	0.087	0.064	0.096	0.062	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.158	0.083	0.059	0.090	0.059	114	0.167	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.158	0.085	0.059	0.090	0.059	114	0.145	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.158	0.083	0.060	0.090	0.058	114	0.123	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.158	0.085	0.061	0.093	0.060	114	0.099	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.158	0.088	0.063	0.097	0.063	114	0.074	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.158	0.087	0.064	0.095	0.063	114	0.049	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.158	0.086	0.062	0.095	0.062	114	0.025	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.158	0.088	0.065	0.099	0.063	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.158	0.088	0.065	0.101	0.063	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.091	0.065	0.104	0.065	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.093	0.066	0.106	0.066	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.094	0.067	0.107	0.067	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.095	0.068	0.109	0.068	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.097	0.069	0.110	0.069	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.098	0.070	0.112	0.070	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.100	0.071	0.113	0.071	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.101	0.072	0.115	0.072	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.102	0.073	0.117	0.073	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.104	0.075	0.118	0.074	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.105	0.076	0.120	0.075	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.107	0.077	0.122	0.076	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.109	0.078	0.124	0.078	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.110	0.079	0.125	0.079	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.112	0.080	0.127	0.080	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.113	0.081	0.129	0.081	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.115	0.082	0.131	0.082	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.117	0.084	0.133	0.083	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.118	0.085	0.135	0.085	114		
Levelized														
(2008-2040)	0.023	0.023	0.026	0.025	24.5	18.4	0.137							
(2009-2040)	0.023	0.022	0.025	0.024	24.9	18.7	0.140							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.8	11.1	0.015							
10 years (2008-17)	0.031	0.030	0.034	0.033	20.5	15.4	0.086							
15 years (2008-22)	0.028	0.027	0.031	0.030	22.4	16.8	0.111							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	59%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Norwalk-Stamford					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.104	0.075	0.116	0.078	-										
2008	0.116	0.085	0.118	0.082	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.109	0.082	0.118	0.076	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.102	0.076	0.110	0.072	60.5	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.097	0.071	0.109	0.069	109.1	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.098	0.073	0.113	0.070	122.1					90	0.028	0.023	0.059	0.030	140
2013	0.094	0.067	0.106	0.066	129.6					40					90
2014	0.095	0.067	0.105	0.067	129.6										40
2015	0.093	0.067	0.105	0.066	129.6										
2016	0.094	0.068	0.108	0.067	129.6										
2017	0.098	0.070	0.112	0.070	129.6										
2018	0.096	0.071	0.110	0.070	129.6										
2019	0.095	0.069	0.111	0.069	129.6										
2020	0.097	0.071	0.115	0.070	129.6										
2021	0.097	0.072	0.116	0.070	129.6										
2022	0.100	0.072	0.120	0.072	129.6										
2023	0.102	0.073	0.122	0.073	129.6										
2024	0.103	0.074	0.124	0.074	129.6										
2025	0.105	0.075	0.125	0.075	129.6										
2026	0.106	0.076	0.127	0.076	129.6										
2027	0.108	0.077	0.129	0.077	129.6										
2028	0.110	0.079	0.131	0.078	129.6										
2029	0.111	0.080	0.133	0.079	129.6										
2030	0.113	0.081	0.135	0.081	129.6										
2031	0.114	0.082	0.137	0.082	129.6										
2032	0.116	0.083	0.139	0.083	129.6										
2033	0.118	0.084	0.141	0.084	129.6										
2034	0.119	0.086	0.143	0.085	129.6										
2035	0.121	0.087	0.145	0.087	129.6										
2036	0.123	0.088	0.147	0.088	129.6										
2037	0.125	0.089	0.149	0.089	129.6										
2038	0.126	0.091	0.151	0.090	129.6										
2039	0.128	0.092	0.153	0.092	129.6										
2040	0.130	0.093	0.156	0.093	129.6										
Levelized															
(2008-2040)	0.106	0.077	0.123	0.076	114.9	0.006	0.005	0.012	0.006	13.4	0.006	0.004	0.012	0.006	10.3
(2009-2040)	0.106	0.076	0.123	0.075	120.0	0.005	0.004	0.011	0.005	14.0	0.006	0.005	0.012	0.006	10.7
5 years (2008-12)	0.105	0.077	0.114	0.074	56.8	0.028	0.023	0.058	0.030	59.0	0.028	0.022	0.057	0.029	26.8
10 years (2008-17)	0.100	0.073	0.111	0.071	91.2	0.015	0.012	0.031	0.016	35.1	0.015	0.012	0.030	0.015	26.9
15 years (2008-22)	0.099	0.072	0.112	0.071	102.6	0.010	0.008	0.022	0.011	24.6	0.010	0.008	0.021	0.011	18.9
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9
PV to 2009											0.135	0.109	0.279	0.141	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.093	0.066	0.104	0.069		0.175	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.103	0.075	0.105	0.073		0.222	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.096	0.072	0.105	0.067		0.233	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.075	0.090	0.067	0.097	0.063	67	0.233	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.135	0.087	0.063	0.097	0.061	114	0.211	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.152	0.087	0.064	0.101	0.062	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.161	0.083	0.059	0.095	0.059	114	0.167	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.161	0.085	0.059	0.094	0.059	114	0.145	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.161	0.083	0.060	0.095	0.058	114	0.123	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.161	0.085	0.061	0.097	0.060	114	0.099	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.161	0.088	0.063	0.101	0.063	114	0.074	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.161	0.087	0.064	0.099	0.063	114	0.049	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.161	0.086	0.062	0.100	0.062	114	0.025	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.161	0.088	0.065	0.104	0.063	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.161	0.088	0.065	0.106	0.063	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.091	0.065	0.109	0.065	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.093	0.066	0.111	0.066	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.094	0.067	0.112	0.067	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.095	0.068	0.114	0.068	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.097	0.069	0.116	0.069	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.098	0.070	0.117	0.070	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.100	0.071	0.119	0.071	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.101	0.072	0.121	0.072	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.102	0.073	0.123	0.073	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.104	0.075	0.124	0.074	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.105	0.076	0.126	0.075	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.107	0.077	0.128	0.076	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.109	0.078	0.130	0.078	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.110	0.079	0.132	0.079	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.112	0.080	0.134	0.080	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.113	0.081	0.136	0.081	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.115	0.082	0.137	0.082	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.117	0.084	0.139	0.083	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.161	0.118	0.085	0.142	0.085	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.140							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.143							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.016							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.087							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.113							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Southwest Connecticut except Norwalk-Stamford					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.098	0.073	0.100	0.076	-										
2008	0.109	0.082	0.102	0.080	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.102	0.079	0.102	0.074	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.102	0.076	0.102	0.072	60.5	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.097	0.071	0.101	0.069	109.1	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.098	0.073	0.105	0.070	122.1					90	0.028	0.023	0.059	0.030	140
2013	0.094	0.067	0.098	0.066	129.6					40					90
2014	0.095	0.067	0.098	0.067	129.6										40
2015	0.093	0.067	0.098	0.066	129.6										
2016	0.094	0.068	0.100	0.067	129.6										
2017	0.098	0.070	0.104	0.070	129.6										
2018	0.096	0.071	0.102	0.070	129.6										
2019	0.095	0.069	0.102	0.069	129.6										
2020	0.097	0.071	0.106	0.070	129.6										
2021	0.097	0.072	0.108	0.070	129.6										
2022	0.100	0.072	0.111	0.072	129.6										
2023	0.102	0.073	0.113	0.073	129.6										
2024	0.103	0.074	0.115	0.074	129.6										
2025	0.105	0.075	0.116	0.075	129.6										
2026	0.106	0.076	0.118	0.076	129.6										
2027	0.108	0.077	0.120	0.077	129.6										
2028	0.110	0.079	0.121	0.078	129.6										
2029	0.111	0.080	0.123	0.079	129.6										
2030	0.113	0.081	0.125	0.081	129.6										
2031	0.114	0.082	0.127	0.082	129.6										
2032	0.116	0.083	0.129	0.083	129.6										
2033	0.118	0.084	0.130	0.084	129.6										
2034	0.119	0.086	0.132	0.085	129.6										
2035	0.121	0.087	0.134	0.087	129.6										
2036	0.123	0.088	0.136	0.088	129.6										
2037	0.125	0.089	0.138	0.089	129.6										
2038	0.126	0.091	0.140	0.090	129.6										
2039	0.128	0.092	0.142	0.092	129.6										
2040	0.130	0.093	0.144	0.093	129.6										
Levelized															
(2008-2040)	0.106	0.077	0.114	0.076	114.9	0.006	0.005	0.012	0.006	13.4	0.006	0.004	0.012	0.006	10.3
(2009-2040)	0.105	0.076	0.114	0.075	120.0	0.005	0.004	0.011	0.005	14.0	0.006	0.005	0.012	0.006	10.7
5 years (2008-12)	0.102	0.076	0.102	0.073	56.8	0.028	0.023	0.058	0.030	59.0	0.028	0.022	0.057	0.029	26.8
10 years (2008-17)	0.099	0.072	0.101	0.070	91.2	0.015	0.012	0.031	0.016	35.1	0.015	0.012	0.030	0.015	26.9
15 years (2008-22)	0.098	0.072	0.102	0.070	102.6	0.010	0.008	0.022	0.011	24.6	0.010	0.008	0.021	0.011	18.9
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9
PV to 2009											0.135	0.109	0.279	0.141	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in	
2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.088	0.064	0.089	0.067		0.175	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.097	0.073	0.090	0.071		0.222	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.091	0.070	0.090	0.065		0.233	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.073	0.090	0.067	0.090	0.063	67	0.233	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.131	0.087	0.063	0.090	0.061	114	0.211	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.147	0.087	0.064	0.093	0.062	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.156	0.083	0.059	0.088	0.059	114	0.167	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.156	0.085	0.059	0.087	0.059	114	0.145	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.156	0.083	0.060	0.088	0.058	114	0.123	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.156	0.085	0.061	0.090	0.060	114	0.099	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.156	0.088	0.063	0.094	0.063	114	0.074	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.156	0.087	0.064	0.092	0.063	114	0.049	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.156	0.086	0.062	0.093	0.062	114	0.025	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.156	0.088	0.065	0.097	0.063	114	0.000	
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.156	0.088	0.065	0.098	0.063	114	0.000	
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.091	0.065	0.101	0.065	114	0.000	
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.093	0.066	0.103	0.066	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.094	0.067	0.104	0.067	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.095	0.068	0.106	0.068	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.097	0.069	0.107	0.069	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.098	0.070	0.109	0.070	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.100	0.071	0.110	0.071	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.101	0.072	0.112	0.072	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.102	0.073	0.114	0.073	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.104	0.075	0.115	0.074	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.105	0.076	0.117	0.075	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.107	0.077	0.119	0.076	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.109	0.078	0.120	0.078	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.110	0.079	0.122	0.079	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.112	0.080	0.124	0.080	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.113	0.081	0.126	0.081	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.115	0.082	0.127	0.082	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.117	0.084	0.129	0.083	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.156	0.118	0.085	0.131	0.085	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.136							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.139							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.015							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.085							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.110							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Constant Dollars

	Connecticut except Southwest Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.099	0.072	0.104	0.075	-										
2008	0.110	0.082	0.105	0.080	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.103	0.079	0.106	0.073	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.100	0.075	0.103	0.071	60.5	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.096	0.070	0.102	0.068	109.1	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.097	0.072	0.105	0.069	122.1					90	0.028	0.023	0.059	0.030	140
2013	0.092	0.066	0.100	0.065	129.6					40					90
2014	0.094	0.066	0.099	0.066	129.6										40
2015	0.091	0.066	0.100	0.065	129.6										
2016	0.092	0.067	0.101	0.066	129.6										
2017	0.096	0.069	0.105	0.068	129.6										
2018	0.094	0.069	0.103	0.069	129.6										
2019	0.093	0.068	0.104	0.067	129.6										
2020	0.095	0.070	0.107	0.069	129.6										
2021	0.096	0.070	0.108	0.069	129.6										
2022	0.099	0.071	0.112	0.071	129.6										
2023	0.101	0.072	0.114	0.072	129.6										
2024	0.102	0.073	0.115	0.073	129.6										
2025	0.103	0.074	0.117	0.074	129.6										
2026	0.105	0.075	0.119	0.075	129.6										
2027	0.106	0.077	0.121	0.076	129.6										
2028	0.108	0.078	0.122	0.077	129.6										
2029	0.110	0.079	0.124	0.078	129.6										
2030	0.111	0.080	0.126	0.079	129.6										
2031	0.113	0.081	0.128	0.080	129.6										
2032	0.114	0.082	0.130	0.082	129.6										
2033	0.116	0.083	0.131	0.083	129.6										
2034	0.118	0.085	0.133	0.084	129.6										
2035	0.119	0.086	0.135	0.085	129.6										
2036	0.121	0.087	0.137	0.086	129.6										
2037	0.123	0.088	0.139	0.088	129.6										
2038	0.125	0.090	0.141	0.089	129.6										
2039	0.127	0.091	0.143	0.090	129.6										
2040	0.128	0.092	0.145	0.091	129.6										
Levelized															
(2008-2040)	0.104	0.076	0.115	0.074	114.9	0.006	0.005	0.012	0.006	13.4	0.006	0.004	0.012	0.006	10.3
(2009-2040)	0.104	0.075	0.115	0.074	120.0	0.005	0.004	0.011	0.005	14.0	0.006	0.005	0.012	0.006	10.7
5 years (2008-12)	0.101	0.076	0.104	0.072	56.8	0.028	0.023	0.058	0.030	59.0	0.028	0.022	0.057	0.029	26.8
10 years (2008-17)	0.097	0.071	0.102	0.069	91.2	0.015	0.012	0.031	0.016	35.1	0.015	0.012	0.030	0.015	26.9
15 years (2008-22)	0.097	0.071	0.104	0.069	102.6	0.010	0.008	0.022	0.011	24.6	0.010	0.008	0.021	0.011	18.9
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9
PV to 2009											0.135	0.109	0.279	0.141	249.3

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Constant Dollar Avoided Cost Results by Screening Zone

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Constant Dollars													
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders					REC Costs	ICAP
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr
Period:														
2007	0.037	0.036	0.041	0.040				0.088	0.064	0.092	0.066		0.175	
2008	0.037	0.036	0.041	0.040	9.3	7.0		0.098	0.072	0.093	0.071		0.222	40.5
2009	0.035	0.035	0.039	0.038	10.4	7.8		0.091	0.069	0.094	0.064		0.233	45.2
2010	0.035	0.035	0.039	0.038	13.5	10.2	0.074	0.089	0.065	0.091	0.062	67	0.233	19.0
2011	0.035	0.034	0.039	0.038	17.9	13.4	0.133	0.085	0.062	0.090	0.060	114	0.211	
2012	0.031	0.030	0.034	0.033	23.1	17.4	0.148	0.086	0.063	0.094	0.060	114	0.189	
2013	0.030	0.029	0.033	0.032	26.2	19.6	0.158	0.082	0.058	0.089	0.057	114	0.167	
2014	0.028	0.028	0.032	0.031	26.2	19.6	0.158	0.084	0.059	0.088	0.058	114	0.145	
2015	0.027	0.027	0.030	0.029	26.2	19.6	0.158	0.082	0.059	0.089	0.057	114	0.123	
2016	0.026	0.025	0.029	0.028	26.2	19.6	0.158	0.083	0.060	0.091	0.059	114	0.099	
2017	0.024	0.024	0.027	0.026	26.2	19.6	0.158	0.086	0.062	0.094	0.062	114	0.074	
2018	0.023	0.023	0.026	0.025	26.2	19.6	0.158	0.085	0.062	0.093	0.062	114	0.049	
2019	0.022	0.022	0.024	0.024	26.2	19.6	0.158	0.084	0.061	0.094	0.061	114	0.025	
2020	0.021	0.020	0.023	0.022	26.2	19.6	0.158	0.086	0.064	0.098	0.062	114		
2021	0.020	0.020	0.022	0.022	26.2	19.6	0.158	0.087	0.064	0.098	0.062	114		
2022	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.090	0.065	0.102	0.064	114		
2023	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.091	0.066	0.103	0.065	114		
2024	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.093	0.067	0.105	0.066	114		
2025	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.094	0.068	0.106	0.067	114		
2026	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.095	0.069	0.108	0.068	114		
2027	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.097	0.070	0.110	0.069	114		
2028	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.098	0.071	0.111	0.070	114		
2029	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.100	0.072	0.113	0.071	114		
2030	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.101	0.073	0.114	0.072	114		
2031	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.103	0.074	0.116	0.073	114		
2032	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.104	0.075	0.118	0.074	114		
2033	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.106	0.076	0.119	0.075	114		
2034	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.107	0.077	0.121	0.076	114		
2035	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.109	0.078	0.123	0.077	114		
2036	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.110	0.079	0.125	0.078	114		
2037	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.112	0.080	0.127	0.080	114		
2038	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.113	0.082	0.128	0.081	114		
2039	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.115	0.083	0.130	0.082	114		
2040	0.019	0.019	0.022	0.021	26.2	19.6	0.158	0.117	0.084	0.132	0.083	114		
Levelized														
(2008-2040)	0.024	0.024	0.027	0.026	23.9	17.9	0.137							
(2009-2040)	0.024	0.023	0.026	0.025	24.5	18.4	0.140							
5 years (2008-12)	0.035	0.034	0.039	0.037	14.7	11.0	0.015							
10 years (2008-17)	0.031	0.031	0.035	0.034	20.1	15.1	0.086							
15 years (2008-22)	0.028	0.028	0.031	0.030	21.9	16.4	0.111							
PV to 2008														
PV to 2009														

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.

EXHIBIT E-1 Inputs - N$

Nominal Dollar Worksheet Inputs

Note: This version has inputs for FCM phase-in in PY 2010-11 through 2012-13, assuming that the PCM price may be depressed in the first couple years due to demand-reduction bids. The phase-in is reflected directly in the capacity revenue column. The avoided capacity cost uses the average between 100% and the phased-in price.

	Real	Nominal	
Retail Adder	10%		except for Vermont, PSNH
Discount Rate	2.22%	4.8%	
Capacity Losses to ISO delivery	3.4%		
Inflation Rate 2007	2.5%		

Development of Load Factors

Summer Peak GWh	CT	ME	NH	RI	VT	NEMA	SEMA	WCMA	MA	non-NE MA
Sep-06	1,215	410	470	348	164	1,008	585	625		
Aug-06	1,742	525	610	469	278	1,374	842	881		
Jul-06	1,559	451	578	417	241	1,267	772	769		
Jun-06	1,530	500	538	389	241	1,217	686	803		
Total Summer	6,046	1,886	2,197	1,623	924	4,867	2,885	3,078	10,830	5,963
Peak 2Aug06 HE1400	7,367	2,022	2,452	1,960	1,036	5,582	3,712	3,760	13,054	7,472
Summer Peak Load Factor	60.3%	68.6%	65.9%	60.9%	65.6%	64.1%	57.2%	60.2%	61.0%	58.7%

Please note: CT subzones estimated as (CT peak lf) * (subzone summer lf)/(CT summer lf), summer lfs from ISO SMD_monthly.xls

		Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
	tons/MWh	0.61	0.60	0.68	0.66
	$/ton externality	$/kWh externality			
2007	60.00	0.037	0.036	0.041	0.040
2008	60.00	0.037	0.036	0.041	0.040
2009	57.79	0.035	0.035	0.039	0.038
2010	57.63	0.035	0.035	0.039	0.038
2011	57.47	0.035	0.034	0.039	0.038
2012	50.54	0.031	0.030	0.034	0.033
2013	48.44	0.030	0.029	0.033	0.032
2014	46.34	0.028	0.028	0.032	0.031
2015	44.24	0.027	0.027	0.030	0.029
2016	42.14	0.026	0.025	0.029	0.028
2017	40.04	0.024	0.024	0.027	0.026
2018	37.94	0.023	0.023	0.026	0.025
2019	35.84	0.022	0.022	0.024	0.024
2020	33.73	0.021	0.020	0.023	0.022
2021	32.68	0.020	0.020	0.022	0.022
2022	31.63	0.019	0.019	0.022	0.021

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S[illegible]er includes June through September; Winter is all other months.

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.099	0.073	0.104	0.076	-										
2008	0.113	0.085	0.109	0.083	-	0.017	0.014	0.034	0.017	-	-	-	-	-	-
2009	0.109	0.083	0.112	0.077	-	0.051	0.041	0.105	0.053	-	0.017	0.014	0.035	0.017	-
2010	0.109	0.081	0.112	0.077	65.1	0.050	0.040	0.105	0.053	78	0.052	0.042	0.108	0.054	-
2011	0.107	0.078	0.113	0.076	120.4	0.031	0.025	0.065	0.033	155	0.051	0.041	0.107	0.055	-
2012	0.110	0.082	0.120	0.079	138.1					102	0.032	0.026	0.067	0.034	158
2013	0.108	0.077	0.117	0.076	150.3					46					104
2014	0.112	0.079	0.118	0.079	154.1										48
2015	0.112	0.081	0.122	0.079	158.0										
2016	0.116	0.085	0.127	0.084	161.9										
2017	0.124	0.089	0.135	0.088	165.9										
2018	0.125	0.092	0.136	0.091	170.1										
2019	0.126	0.092	0.141	0.091	174.3										
2020	0.132	0.098	0.149	0.095	178.7										
2021	0.136	0.100	0.155	0.098	183.2										
2022	0.144	0.104	0.164	0.103	187.8										
2023	0.150	0.108	0.171	0.107	192.4										
2024	0.156	0.112	0.177	0.111	197.3										
2025	0.162	0.117	0.184	0.116	202.2										
2026	0.169	0.121	0.192	0.121	207.2										
2027	0.176	0.126	0.199	0.125	212.4										
2028	0.183	0.131	0.207	0.130	217.7										
2029	0.190	0.136	0.216	0.136	223.2										
2030	0.197	0.142	0.224	0.141	228.8										
2031	0.205	0.147	0.233	0.147	234.5										
2032	0.214	0.153	0.242	0.152	240.3										
2033	0.222	0.159	0.252	0.158	246.4										
2034	0.231	0.166	0.262	0.165	252.5										
2035	0.240	0.172	0.273	0.171	258.8										
2036	0.250	0.179	0.283	0.178	265.3										
2037	0.260	0.186	0.295	0.185	271.9										
2038	0.270	0.194	0.306	0.193	278.7										
2039	0.281	0.202	0.319	0.200	285.7										
2040	0.292	0.210	0.331	0.208	292.8										
Levelized															
(2008-2040)	0.148	0.107	0.163	0.106	162.3	0.008	0.006	0.017	0.008	18.9	0.008	0.006	0.016	0.008	14.5
(2009-2040)	0.150	0.109	0.167	0.107	172.3	0.007	0.006	0.016	0.008	20.1	0.008	0.007	0.017	0.009	15.4
5 years (2008-12)	0.110	0.082	0.113	0.078	61.0	0.030	0.024	0.063	0.032	63.4	0.030	0.024	0.061	0.031	28.8
10 years (2008-17)	0.112	0.082	0.118	0.079	103.8	0.017	0.014	0.035	0.018	39.9	0.017	0.013	0.034	0.017	30.6
15 years (2008-22)	0.117	0.086	0.126	0.084	123.1	0.013	0.010	0.026	0.013	29.5	0.012	0.010	0.025	0.013	22.6
PV to 2008						0.138	0.112	0.286	0.145	326.2	0.135	0.109	0.280	0.142	250.0
PV to 2009											0.142	0.114	0.294	0.149	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and Inflation					REC Costs	ICAP	DRIPE for Installations in 2008						DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.089	0.064	0.093	0.067		0.175											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.098	0.073	0.094	0.071		0.222	40.5	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.092	0.070	0.095	0.064		0.233	45.2	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.079	0.090	0.066	0.092	0.062	67	0.233	19.0	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.039	0.038	0.043	0.042	26.9	21.7	0.147	0.086	0.062	0.091	0.060	114	0.211		0.028	0.023	0.059	0.030	140	0.048	0.037	0.097	0.050	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.168	0.087	0.064	0.095	0.061	114	0.189						90	0.028	0.023	0.059	0.030	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.183	0.083	0.059	0.090	0.058	114	0.167						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.187	0.084	0.059	0.089	0.059	114	0.145											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.192	0.082	0.059	0.090	0.058	114	0.123											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.197	0.084	0.061	0.092	0.060	114	0.099											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.202	0.087	0.063	0.095	0.062	114	0.074											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.207	0.086	0.063	0.094	0.063	114	0.049											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.212	0.085	0.062	0.095	0.061	114	0.025											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.217	0.087	0.064	0.098	0.063	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.223	0.087	0.064	0.100	0.063	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.228	0.091	0.065	0.103	0.065	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.234	0.092	0.066	0.104	0.066	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.240	0.093	0.067	0.106	0.067	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.246	0.095	0.068	0.107	0.068	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.252	0.096	0.069	0.109	0.069	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.258	0.097	0.070	0.111	0.070	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.265	0.099	0.071	0.112	0.071	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.271	0.100	0.072	0.114	0.072	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.278	0.102	0.073	0.115	0.073	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.285	0.103	0.074	0.117	0.074	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.292	0.105	0.075	0.119	0.075	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.300	0.106	0.076	0.121	0.076	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.307	0.108	0.077	0.122	0.077	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.315	0.109	0.079	0.124	0.078	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.323	0.111	0.080	0.126	0.079	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.331	0.113	0.081	0.128	0.080	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.339	0.114	0.082	0.130	0.081	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.348	0.116	0.083	0.131	0.083	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.356	0.117	0.084	0.133	0.084	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.213																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.217																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.016																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.099																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.136																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-Al Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Si ludes June through September; Winter is all other months.
Syna nergy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	69%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Maine					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.082	0.061	0.082	0.063	-										
2008	0.094	0.072	0.089	0.068	-	0.015	0.013	0.024	0.010	-	-	-	-	-	-
2009	0.094	0.072	0.087	0.066	-	0.046	0.038	0.073	0.031	-	0.016	0.013	0.025	0.011	-
2010	0.092	0.068	0.089	0.064	65.1	0.044	0.036	0.070	0.030	78	0.047	0.039	0.075	0.032	-
2011	0.090	0.068	0.089	0.064	120.4	0.027	0.022	0.044	0.018	155	0.045	0.037	0.072	0.030	-
2012	0.094	0.070	0.097	0.067	138.1					102	0.028	0.023	0.045	0.019	158
2013	0.091	0.067	0.094	0.066	150.3					46					104
2014	0.097	0.070	0.099	0.069	154.1										48
2015	0.099	0.072	0.102	0.069	158.0										
2016	0.104	0.075	0.108	0.074	161.9										
2017	0.109	0.080	0.114	0.077	165.9										
2018	0.108	0.081	0.115	0.079	170.1										
2019	0.111	0.081	0.122	0.081	174.3										
2020	0.116	0.084	0.125	0.083	178.7										
2021	0.121	0.089	0.132	0.086	183.2										
2022	0.126	0.092	0.140	0.089	187.8										
2023	0.131	0.096	0.146	0.093	192.4										
2024	0.136	0.100	0.151	0.096	197.3										
2025	0.142	0.104	0.157	0.100	202.2										
2026	0.147	0.108	0.164	0.104	207.2										
2027	0.153	0.112	0.170	0.108	212.4										
2028	0.159	0.117	0.177	0.113	217.7										
2029	0.166	0.121	0.184	0.117	223.2										
2030	0.172	0.126	0.191	0.122	228.8										
2031	0.179	0.131	0.199	0.127	234.5										
2032	0.186	0.136	0.207	0.132	240.3										
2033	0.194	0.142	0.215	0.137	246.4										
2034	0.202	0.148	0.224	0.142	252.5										
2035	0.210	0.153	0.233	0.148	258.8										
2036	0.218	0.160	0.242	0.154	265.3										
2037	0.227	0.166	0.252	0.160	271.9										
2038	0.236	0.173	0.262	0.167	278.7										
2039	0.245	0.179	0.272	0.173	285.7										
2040	0.255	0.187	0.283	0.180	292.8										
Levelized															
(2008-2040)	0.129	0.095	0.137	0.091	162.3	0.004	0.003	0.006	0.003	11.5	0.007	0.006	0.011	0.005	14.5
(2009-2040)	0.131	0.096	0.140	0.093	172.3	0.004	0.003	0.006	0.002	11.9	0.007	0.006	0.012	0.005	15.4
5 years (2008-12)	0.093	0.070	0.090	0.066	61.0	0.027	0.022	0.042	0.018	66.8	0.026	0.022	0.042	0.018	28.8
10 years (2008-17)	0.096	0.071	0.096	0.068	103.8	0.013	0.011	0.021	0.009	38.0	0.015	0.012	0.023	0.010	30.6
15 years (2008-22)	0.101	0.075	0.104	0.072	123.1	0.009	0.007	0.014	0.006	25.4	0.011	0.009	0.017	0.007	22.6
PV to 2008						0.123	0.102	0.196	0.083	326.2	0.121	0.099	0.191	0.082	250.0
PV to 2009											0.127	0.104	0.200	0.085	262.0

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and Inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.075	0.056	0.074	0.058		0.000											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.083	0.064	0.078	0.060		0.044	40.5	0.015	0.012	0.024	0.010	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.080	0.061	0.075	0.057		0.078	45.2	0.044	0.037	0.069	0.030	-	0.015	0.012	0.024	0.010	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.070	0.076	0.057	0.074	0.053	67	0.100	19.0	0.041	0.034	0.065	0.028	72	0.044	0.037	0.069	0.030	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.129	0.073	0.055	0.072	0.051	114	0.121		0.025	0.020	0.040	0.017	140	0.041	0.034	0.065	0.028	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.148	0.074	0.055	0.076	0.053	114	0.135						90	0.025	0.020	0.040	0.017	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.161	0.070	0.051	0.072	0.050	114	0.143						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.165	0.073	0.052	0.074	0.052	114	0.145											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.169	0.072	0.052	0.075	0.050	114	0.141											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.173	0.074	0.053	0.077	0.053	114	0.127											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.178	0.076	0.056	0.080	0.054	114	0.106											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.182	0.074	0.055	0.079	0.054	114	0.071											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.187	0.075	0.054	0.082	0.054	114	0.035											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.191	0.076	0.056	0.082	0.055	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.196	0.078	0.057	0.085	0.055	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.201	0.079	0.058	0.088	0.056	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.206	0.080	0.059	0.089	0.057	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.211	0.081	0.060	0.090	0.058	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.216	0.083	0.061	0.092	0.058	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.222	0.084	0.061	0.093	0.059	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.227	0.085	0.062	0.094	0.060	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.233	0.086	0.063	0.096	0.061	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.239	0.088	0.064	0.097	0.062	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.245	0.089	0.065	0.099	0.063	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.251	0.090	0.066	0.100	0.064	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.257	0.091	0.067	0.102	0.065	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.264	0.093	0.068	0.103	0.066	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.270	0.094	0.069	0.104	0.067	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.277	0.095	0.070	0.106	0.067	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.284	0.097	0.071	0.108	0.068	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.291	0.098	0.072	0.109	0.069	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.298	0.100	0.073	0.111	0.070	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.306	0.101	0.074	0.112	0.071	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.313	0.103	0.075	0.114	0.073	114												
Levelized																								
(2008-2040)	0.034	0.034	0.038	0.037	39.7	29.8	0.188																	
(2009-2040)	0.034	0.034	0.038	0.037	40.7	30.5	0.191																	
5 years (2008-12)	0.037	0.037	0.041	0.040	20.0	15.0	0.015																	
10 years (2008-17)	0.035	0.034	0.039	0.038	26.0	19.5	0.087																	
15 years (2008-22)	0.033	0.032	0.037	0.036	29.4	22.0	0.120																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-A 1 Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S cludes June through September; Winter is all other months.
Sy nergy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	All of Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.094	0.069	0.095	0.072	-										
2008	0.108	0.080	0.100	0.076	-	0.016	0.013	0.029	0.012	-	-	-	-	-	-
2009	0.103	0.079	0.102	0.074	-	0.049	0.039	0.088	0.036	-	0.017	0.014	0.030	0.012	-
2010	0.105	0.077	0.106	0.072	65.1	0.046	0.037	0.084	0.034	78	0.050	0.040	0.090	0.037	-
2011	0.103	0.076	0.107	0.072	120.4	0.029	0.023	0.052	0.021	155	0.047	0.038	0.086	0.035	-
2012	0.106	0.079	0.111	0.077	138.1					102	0.030	0.024	0.053	0.022	158
2013	0.103	0.075	0.109	0.075	150.3					46					104
2014	0.108	0.077	0.112	0.078	154.1										48
2015	0.109	0.080	0.120	0.079	158.0										
2016	0.115	0.083	0.124	0.085	161.9										
2017	0.121	0.087	0.130	0.086	165.9										
2018	0.121	0.089	0.132	0.089	170.1										
2019	0.123	0.089	0.138	0.089	174.3										
2020	0.128	0.094	0.142	0.092	178.7										
2021	0.133	0.097	0.152	0.096	183.2										
2022	0.141	0.101	0.158	0.100	187.8										
2023	0.146	0.105	0.165	0.104	192.4										
2024	0.152	0.109	0.171	0.108	197.3										
2025	0.158	0.113	0.178	0.113	202.2										
2026	0.164	0.118	0.185	0.117	207.2										
2027	0.171	0.122	0.193	0.122	212.4										
2028	0.178	0.127	0.200	0.127	217.7										
2029	0.185	0.132	0.208	0.132	223.2										
2030	0.192	0.138	0.216	0.137	228.8										
2031	0.200	0.143	0.225	0.142	234.5										
2032	0.208	0.149	0.234	0.148	240.3										
2033	0.216	0.155	0.243	0.154	246.4										
2034	0.225	0.161	0.253	0.160	252.5										
2035	0.234	0.167	0.263	0.167	258.8										
2036	0.243	0.174	0.274	0.173	265.3										
2037	0.253	0.181	0.285	0.180	271.9										
2038	0.263	0.188	0.296	0.187	278.7										
2039	0.273	0.196	0.308	0.195	285.7										
2040	0.284	0.204	0.320	0.203	292.8										
Levelized															
(2008-2040)	0.144	0.104	0.157	0.103	162.3	0.008	0.006	0.014	0.006	18.9	0.007	0.006	0.013	0.005	14.5
(2009-2040)	0.146	0.106	0.160	0.104	172.3	0.007	0.006	0.013	0.005	20.1	0.008	0.006	0.014	0.006	15.4
5 years (2008-12)	0.105	0.078	0.105	0.074	61.0	0.028	0.023	0.051	0.021	63.4	0.028	0.022	0.050	0.020	28.8
10 years (2008-17)	0.108	0.079	0.111	0.077	103.8	0.016	0.013	0.029	0.012	39.9	0.016	0.013	0.028	0.011	30.6
15 years (2008-22)	0.113	0.083	0.119	0.081	123.1	0.012	0.010	0.021	0.009	29.5	0.012	0.009	0.021	0.008	22.6
PV to 2008						0.130	0.105	0.234	0.095	326.2	0.127	0.103	0.229	0.093	250.0
PV to 2009											0.133	0.108	0.240	0.097	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																	
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and Inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.084	0.061	0.085	0.064		0.150											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.094	0.070	0.087	0.066		0.156	40.5	0.016	0.013	0.029	0.012	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.088	0.067	0.087	0.062		0.156	45.2	0.046	0.037	0.083	0.034	-	0.016	0.013	0.029	0.012	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.078	0.087	0.063	0.087	0.059	67	0.167	19.0	0.043	0.035	0.078	0.031	72	0.046	0.037	0.083	0.034	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.145	0.083	0.060	0.086	0.058	114	0.181		0.026	0.021	0.047	0.019	140	0.043	0.035	0.078	0.031	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.166	0.083	0.062	0.088	0.060	114	0.189						90	0.026	0.021	0.047	0.019	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.181	0.079	0.057	0.084	0.057	114	0.191						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.185	0.081	0.057	0.084	0.058	114	0.187											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.190	0.080	0.058	0.088	0.057	114	0.176											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.195	0.082	0.059	0.088	0.060	114	0.155											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.200	0.084	0.061	0.091	0.060	114	0.127											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.205	0.083	0.061	0.090	0.061	114	0.092											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.210	0.083	0.060	0.092	0.060	114	0.049											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.215	0.084	0.062	0.094	0.061	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.220	0.086	0.062	0.098	0.062	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.226	0.088	0.063	0.099	0.063	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.232	0.089	0.064	0.101	0.064	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.237	0.091	0.065	0.102	0.065	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.243	0.092	0.066	0.104	0.066	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.249	0.093	0.067	0.105	0.067	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.256	0.095	0.068	0.107	0.068	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.262	0.096	0.069	0.108	0.069	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.269	0.098	0.070	0.110	0.070	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.275	0.099	0.071	0.112	0.071	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.282	0.100	0.072	0.113	0.072	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.289	0.102	0.073	0.115	0.073	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.296	0.103	0.074	0.116	0.074	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.304	0.105	0.075	0.118	0.075	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.311	0.106	0.076	0.120	0.076	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.319	0.108	0.077	0.122	0.077	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.327	0.109	0.078	0.123	0.078	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.335	0.111	0.080	0.125	0.079	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.344	0.113	0.081	0.127	0.080	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.352	0.114	0.082	0.129	0.081	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.211																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.215																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.016																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.098																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.135																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-A[illegible] Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S[illegible]ludes June through September; Winter is all other months.
Syn[illegible]nergy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	66%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	New Hampshire					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.089	0.066	0.090	0.069	-										
2008	0.102	0.077	0.094	0.072	-	0.016	0.015	0.029	0.015	-	-	-	-	-	-
2009	0.098	0.076	0.094	0.070	-	0.044	0.039	0.079	0.036	-	0.016	0.015	0.030	0.015	-
2010	0.099	0.073	0.097	0.069	65.1	0.042	0.036	0.075	0.032	78	0.046	0.040	0.081	0.037	-
2011	0.097	0.073	0.097	0.068	120.4	0.026	0.022	0.046	0.020	155	0.043	0.037	0.077	0.033	-
2012	0.101	0.076	0.105	0.073	138.1					102	0.027	0.023	0.047	0.020	158
2013	0.099	0.072	0.103	0.071	150.3					46					104
2014	0.104	0.075	0.107	0.074	154.1										48
2015	0.105	0.077	0.111	0.075	158.0										
2016	0.110	0.080	0.117	0.081	161.9										
2017	0.116	0.085	0.124	0.083	165.9										
2018	0.116	0.087	0.123	0.086	170.1										
2019	0.119	0.087	0.130	0.087	174.3										
2020	0.123	0.091	0.135	0.090	178.7										
2021	0.128	0.094	0.142	0.092	183.2										
2022	0.133	0.098	0.150	0.096	187.8										
2023	0.139	0.102	0.156	0.100	192.4										
2024	0.144	0.106	0.162	0.104	197.3										
2025	0.150	0.111	0.168	0.108	202.2										
2026	0.156	0.115	0.175	0.112	207.2										
2027	0.162	0.120	0.182	0.117	212.4										
2028	0.169	0.124	0.189	0.121	217.7										
2029	0.176	0.129	0.197	0.126	223.2										
2030	0.183	0.135	0.205	0.131	228.8										
2031	0.190	0.140	0.213	0.136	234.5										
2032	0.197	0.145	0.221	0.142	240.3										
2033	0.205	0.151	0.230	0.147	246.4										
2034	0.213	0.157	0.239	0.153	252.5										
2035	0.222	0.164	0.249	0.159	258.8										
2036	0.231	0.170	0.259	0.166	265.3										
2037	0.240	0.177	0.269	0.172	271.9										
2038	0.250	0.184	0.280	0.179	278.7										
2039	0.259	0.191	0.291	0.186	285.7										
2040	0.270	0.199	0.303	0.194	292.8										
Levelized															
(2008-2040)	0.137	0.101	0.147	0.098	162.3	0.004	0.003	0.007	0.003	11.5	0.007	0.006	0.012	0.005	14.5
(2009-2040)	0.139	0.103	0.151	0.100	172.3	0.004	0.003	0.006	0.003	11.9	0.007	0.006	0.013	0.006	15.4
5 years (2008-12)	0.099	0.075	0.097	0.070	61.0	0.026	0.022	0.046	0.021	66.8	0.026	0.022	0.046	0.020	28.8
10 years (2008-17)	0.102	0.076	0.104	0.073	103.8	0.013	0.011	0.023	0.010	38.0	0.014	0.012	0.025	0.011	30.6
15 years (2008-22)	0.108	0.080	0.112	0.077	123.1	0.009	0.007	0.015	0.007	25.4	0.011	0.009	0.019	0.008	22.6
PV to 2008						0.119	0.104	0.213	0.096	326.2	0.117	0.102	0.208	0.093	250.0
PV to 2009											0.122	0.107	0.218	0.098	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in

2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.081	0.060	0.081	0.063		0.000											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.090	0.068	0.084	0.064		0.000	40.5	0.015	0.014	0.028	0.014	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.085	0.066	0.081	0.060		0.019	45.2	0.042	0.037	0.076	0.034	-	0.015	0.014	0.028	0.014	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.073	0.083	0.062	0.081	0.058	67	0.035	19.0	0.039	0.034	0.069	0.030	72	0.042	0.037	0.076	0.034	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.134	0.079	0.059	0.080	0.056	114	0.063		0.024	0.020	0.042	0.018	140	0.039	0.034	0.069	0.030	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.154	0.080	0.060	0.083	0.057	114	0.085						90	0.024	0.020	0.042	0.018	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.168	0.076	0.055	0.079	0.054	114	0.100						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.172	0.078	0.056	0.081	0.056	114	0.110											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.176	0.077	0.056	0.082	0.055	114	0.111											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.180	0.079	0.057	0.084	0.058	114	0.103											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.185	0.082	0.060	0.087	0.058	114	0.088											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.190	0.080	0.059	0.085	0.059	114	0.066											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.194	0.080	0.058	0.088	0.058	114	0.036											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.199	0.081	0.060	0.089	0.059	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.204	0.082	0.061	0.091	0.059	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.209	0.084	0.062	0.094	0.060	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.214	0.085	0.063	0.095	0.061	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.220	0.086	0.064	0.097	0.062	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.225	0.087	0.065	0.098	0.063	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.231	0.089	0.065	0.100	0.064	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.237	0.090	0.066	0.101	0.065	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.243	0.091	0.067	0.102	0.066	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.249	0.093	0.068	0.104	0.067	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.255	0.094	0.069	0.105	0.068	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.261	0.095	0.070	0.107	0.069	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.268	0.097	0.071	0.109	0.070	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.275	0.098	0.072	0.110	0.071	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.281	0.100	0.073	0.112	0.072	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.288	0.101	0.074	0.113	0.073	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.296	0.103	0.076	0.115	0.074	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.303	0.104	0.077	0.117	0.075	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.311	0.105	0.078	0.118	0.076	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.318	0.107	0.079	0.120	0.077	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.326	0.109	0.080	0.122	0.078	114												
Levelized																								
(2008-2040)	0.034	0.034	0.038	0.037	39.7	29.8	0.195																	
(2009-2040)	0.034	0.034	0.038	0.037	40.7	30.5	0.199																	
5 years (2008-12)	0.037	0.037	0.041	0.040	20.0	15.0	0.015																	
10 years (2008-17)	0.035	0.034	0.039	0.038	26.0	19.5	0.090																	
15 years (2008-22)	0.033	0.032	0.037	0.036	29.4	22.0	0.125																	
PV to 2008																								
PV to 2009																								

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Rhode Island					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.092	0.067	0.093	0.070	-										
2008	0.108	0.079	0.098	0.074	-	0.015	0.012	0.025	0.011	-	-	-	-	-	-
2009	0.101	0.077	0.102	0.071	-	0.045	0.036	0.074	0.033	-	0.015	0.012	0.025	0.011	-
2010	0.103	0.076	0.104	0.070	65.1	0.043	0.035	0.071	0.032	78	0.046	0.037	0.076	0.034	-
2011	0.101	0.074	0.105	0.069	120.4	0.027	0.022	0.044	0.020	155	0.044	0.036	0.073	0.033	-
2012	0.105	0.078	0.108	0.074	138.1					102	0.028	0.022	0.045	0.020	158
2013	0.101	0.074	0.106	0.073	150.3					46					104
2014	0.107	0.076	0.110	0.075	154.1										48
2015	0.108	0.078	0.117	0.076	158.0										
2016	0.113	0.082	0.122	0.082	161.9										
2017	0.120	0.087	0.129	0.085	165.9										
2018	0.120	0.089	0.129	0.088	170.1										
2019	0.123	0.089	0.136	0.089	174.3										
2020	0.126	0.093	0.141	0.093	178.7										
2021	0.131	0.098	0.149	0.095	183.2										
2022	0.141	0.100	0.156	0.101	187.8										
2023	0.147	0.104	0.162	0.105	192.4										
2024	0.153	0.108	0.169	0.109	197.3										
2025	0.159	0.112	0.176	0.114	202.2										
2026	0.165	0.117	0.183	0.118	207.2										
2027	0.172	0.121	0.190	0.123	212.4										
2028	0.179	0.126	0.197	0.128	217.7										
2029	0.186	0.131	0.205	0.133	223.2										
2030	0.193	0.137	0.214	0.138	228.8										
2031	0.201	0.142	0.222	0.144	234.5										
2032	0.209	0.148	0.231	0.150	240.3										
2033	0.217	0.154	0.240	0.156	246.4										
2034	0.226	0.160	0.250	0.162	252.5										
2035	0.235	0.166	0.260	0.168	258.8										
2036	0.244	0.173	0.270	0.175	265.3										
2037	0.254	0.180	0.281	0.182	271.9										
2038	0.264	0.187	0.292	0.189	278.7										
2039	0.275	0.194	0.304	0.197	285.7										
2040	0.286	0.202	0.316	0.205	292.8										
Levelized															
(2008-2040)	0.143	0.103	0.154	0.102	162.3	0.007	0.006	0.012	0.005	18.9	0.007	0.006	0.011	0.005	14.5
(2009-2040)	0.145	0.105	0.158	0.104	172.3	0.007	0.005	0.011	0.005	20.1	0.007	0.006	0.012	0.005	15.4
5 years (2008-12)	0.104	0.077	0.103	0.071	61.0	0.026	0.021	0.043	0.019	63.4	0.026	0.021	0.043	0.019	28.8
10 years (2008-17)	0.106	0.078	0.109	0.074	103.8	0.015	0.012	0.024	0.011	39.9	0.014	0.012	0.024	0.011	30.6
15 years (2008-22)	0.112	0.082	0.118	0.079	123.1	0.011	0.009	0.018	0.008	29.5	0.011	0.009	0.018	0.008	22.6
PV to 2008						0.121	0.098	0.198	0.089	326.2	0.118	0.096	0.194	0.087	250.0
PV to 2009											0.124	0.100	0.203	0.091	262.0

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs		DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy	ICAP	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.083	0.061	0.084	0.063		0.050											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.095	0.069	0.087	0.065		0.067	40.5	0.015	0.012	0.024	0.010	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.087	0.066	0.088	0.060		0.078	45.2	0.043	0.035	0.070	0.031	-	0.015	0.012	0.024	0.010	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.079	0.086	0.064	0.087	0.058	67	0.083	19.0	0.040	0.033	0.066	0.030	72	0.043	0.035	0.070	0.031	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.145	0.082	0.060	0.085	0.056	114	0.106		0.025	0.020	0.040	0.018	140	0.040	0.033	0.066	0.030	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.167	0.083	0.061	0.085	0.058	114	0.122						90	0.025	0.020	0.040	0.018	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.181	0.078	0.057	0.082	0.056	114	0.131						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.186	0.081	0.057	0.083	0.056	114	0.135											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.190	0.079	0.057	0.086	0.055	114	0.141											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.195	0.081	0.059	0.087	0.058	114	0.134											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.200	0.084	0.061	0.090	0.059	114	0.116											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.205	0.083	0.060	0.088	0.060	114	0.088											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.210	0.083	0.060	0.091	0.060	114	0.049											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.216	0.083	0.062	0.093	0.061	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.221	0.084	0.063	0.096	0.061	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.226	0.089	0.063	0.098	0.064	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.232	0.090	0.064	0.099	0.064	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.238	0.091	0.065	0.101	0.065	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.244	0.093	0.065	0.102	0.066	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.250	0.094	0.066	0.104	0.067	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.256	0.095	0.067	0.105	0.068	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.263	0.097	0.068	0.107	0.069	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.269	0.098	0.069	0.108	0.070	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.276	0.100	0.070	0.110	0.071	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.283	0.101	0.071	0.112	0.072	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.290	0.102	0.072	0.113	0.073	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.297	0.104	0.073	0.115	0.074	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.305	0.105	0.075	0.117	0.076	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.312	0.107	0.076	0.118	0.077	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.320	0.109	0.077	0.120	0.078	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.328	0.110	0.078	0.122	0.079	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.336	0.112	0.079	0.123	0.080	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.345	0.113	0.080	0.125	0.081	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.353	0.115	0.081	0.127	0.082	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.211																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.215																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.016																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.098																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.135																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-A... l Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S... ...cludes June through September; Winter is all other months.
Sy... ...Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Inflation	2.5%
Retail Adder	11%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	66%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Vermont					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.096	0.071	0.097	0.073	-										
2008	0.109	0.082	0.101	0.078	-	0.015	0.012	0.025	0.010	-	-	-	-	-	-
2009	0.105	0.081	0.105	0.074	-	0.044	0.035	0.075	0.030	-	0.015	0.012	0.026	0.010	-
2010	0.107	0.080	0.106	0.075	65.8	0.042	0.033	0.072	0.029	78	0.045	0.036	0.077	0.031	-
2011	0.103	0.077	0.107	0.073	121.7	0.026	0.021	0.045	0.018	155	0.043	0.034	0.074	0.029	-
2012	0.107	0.080	0.112	0.078	139.5					102	0.027	0.021	0.046	0.018	158
2013	0.106	0.076	0.113	0.077	151.9					46					104
2014	0.111	0.079	0.116	0.079	155.7										48
2015	0.112	0.080	0.120	0.081	159.5										
2016	0.116	0.085	0.125	0.087	163.5										
2017	0.124	0.090	0.131	0.088	167.6										
2018	0.123	0.090	0.132	0.092	171.8										
2019	0.124	0.089	0.137	0.093	176.1										
2020	0.131	0.095	0.144	0.096	180.5										
2021	0.138	0.098	0.152	0.097	185.0										
2022	0.144	0.102	0.158	0.102	189.7										
2023	0.150	0.106	0.164	0.106	194.4										
2024	0.156	0.110	0.171	0.111	199.3										
2025	0.162	0.115	0.178	0.115	204.2										
2026	0.169	0.119	0.185	0.120	209.3										
2027	0.175	0.124	0.192	0.124	214.6										
2028	0.182	0.129	0.200	0.129	219.9										
2029	0.190	0.134	0.208	0.134	225.4										
2030	0.197	0.140	0.216	0.140	231.1										
2031	0.205	0.145	0.225	0.145	236.8										
2032	0.213	0.151	0.234	0.151	242.8										
2033	0.222	0.157	0.243	0.157	248.8										
2034	0.231	0.163	0.253	0.164	255.1										
2035	0.240	0.170	0.263	0.170	261.4										
2036	0.249	0.177	0.273	0.177	268.0										
2037	0.259	0.184	0.284	0.184	274.7										
2038	0.270	0.191	0.295	0.191	281.5										
2039	0.280	0.199	0.307	0.199	288.6										
2040	0.291	0.207	0.319	0.207	295.8										
Levelized															
(2008-2040)	0.147	0.106	0.157	0.105	163.9	0.004	0.003	0.007	0.003	11.5	0.007	0.005	0.011	0.005	14.5
(2009-2040)	0.149	0.107	0.161	0.107	174.0	0.004	0.003	0.006	0.002	11.9	0.007	0.006	0.012	0.005	15.4
5 years (2008-12)	0.106	0.080	0.106	0.075	61.7	0.026	0.020	0.043	0.017	66.8	0.025	0.020	0.043	0.017	28.8
10 years (2008-17)	0.109	0.081	0.112	0.078	104.8	0.013	0.010	0.022	0.009	38.0	0.014	0.011	0.024	0.010	30.6
15 years (2008-22)	0.115	0.084	0.121	0.083	124.4	0.009	0.007	0.014	0.006	25.4	0.011	0.008	0.018	0.007	22.6
PV to 2008						0.119	0.094	0.201	0.080	326.2	0.116	0.092	0.197	0.079	250.0
PV to 2009											0.122	0.096	0.206	0.082	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

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FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.086	0.063	0.087	0.065		0.062											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.094	0.071	0.088	0.067		0.111	40.5	0.015	0.012	0.025	0.010	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.088	0.068	0.089	0.062		0.140	45.2	0.042	0.034	0.071	0.029	-	0.015	0.012	0.025	0.010	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.074	0.088	0.065	0.087	0.061	67	0.152	19.0	0.039	0.031	0.067	0.027	72	0.042	0.034	0.071	0.029	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.136	0.083	0.061	0.086	0.058	114	0.159		0.024	0.019	0.041	0.016	140	0.039	0.031	0.067	0.027	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.156	0.084	0.062	0.087	0.060	114	0.172						90	0.024	0.019	0.041	0.016	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.170	0.080	0.057	0.086	0.058	114	0.180						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.174	0.082	0.058	0.086	0.058	114	0.176											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.179	0.081	0.058	0.087	0.058	114	0.176											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.183	0.082	0.060	0.089	0.061	114	0.141											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.188	0.086	0.062	0.091	0.061	114	0.106											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.192	0.084	0.061	0.090	0.062	114	0.071											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.197	0.083	0.059	0.091	0.062	114	0.035											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.202	0.085	0.062	0.094	0.062	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.207	0.088	0.062	0.097	0.062	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.212	0.090	0.063	0.098	0.064	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.217	0.091	0.064	0.100	0.064	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.223	0.092	0.065	0.101	0.065	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.229	0.094	0.066	0.103	0.066	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.234	0.095	0.067	0.104	0.067	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.240	0.096	0.068	0.105	0.068	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.246	0.098	0.069	0.107	0.069	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.252	0.099	0.070	0.109	0.070	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.259	0.101	0.071	0.110	0.071	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.265	0.102	0.072	0.112	0.072	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.272	0.104	0.073	0.113	0.073	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.278	0.105	0.074	0.115	0.074	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.285	0.107	0.075	0.117	0.076	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.293	0.108	0.077	0.118	0.077	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.300	0.110	0.078	0.120	0.078	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.307	0.111	0.079	0.122	0.079	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.315	0.113	0.080	0.124	0.080	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.323	0.114	0.081	0.125	0.081	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.331	0.116	0.082	0.127	0.082	114												
Levelized																								
(2008-2040)	0.034	0.034	0.038	0.037	39.7	29.8	0.198																	
(2009-2040)	0.034	0.034	0.038	0.037	40.7	30.5	0.202																	
5 years (2008-12)	0.037	0.037	0.041	0.040	20.0	15.0	0.015																	
10 years (2008-17)	0.035	0.034	0.039	0.038	26.0	19.5	0.092																	
15 years (2008-22)	0.033	0.032	0.037	0.036	29.4	22.0	0.127																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-Al[illegible] Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S[illegible]cludes June through September; Winter is all other months.
Sy[illegible]nergy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	64%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Northeast Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.094	0.069	0.096	0.072	-										
2008	0.108	0.080	0.101	0.077	-	0.016	0.013	0.030	0.013	-	-	-	-	-	-
2009	0.104	0.079	0.104	0.075	-	0.046	0.040	0.088	0.039	-	0.016	0.014	0.030	0.013	-
2010	0.106	0.077	0.107	0.073	65.1	0.044	0.038	0.084	0.036	78	0.047	0.041	0.090	0.040	-
2011	0.104	0.075	0.108	0.073	120.4	0.027	0.024	0.053	0.023	155	0.045	0.039	0.086	0.037	-
2012	0.107	0.080	0.114	0.079	138.1					102	0.028	0.024	0.054	0.023	158
2013	0.104	0.076	0.112	0.076	150.3					46					104
2014	0.109	0.078	0.114	0.078	154.1										48
2015	0.110	0.080	0.122	0.079	158.0										
2016	0.117	0.083	0.126	0.086	161.9										
2017	0.122	0.088	0.132	0.086	165.9										
2018	0.122	0.089	0.133	0.091	170.1										
2019	0.125	0.090	0.139	0.091	174.3										
2020	0.130	0.094	0.144	0.092	178.7										
2021	0.135	0.097	0.155	0.096	183.2										
2022	0.142	0.101	0.160	0.100	187.8										
2023	0.147	0.105	0.167	0.104	192.4										
2024	0.153	0.110	0.173	0.108	197.3										
2025	0.159	0.114	0.180	0.113	202.2										
2026	0.166	0.118	0.187	0.117	207.2										
2027	0.172	0.123	0.195	0.122	212.4										
2028	0.179	0.128	0.203	0.127	217.7										
2029	0.186	0.133	0.211	0.132	223.2										
2030	0.194	0.138	0.219	0.137	228.8										
2031	0.202	0.144	0.228	0.142	234.5										
2032	0.210	0.150	0.237	0.148	240.3										
2033	0.218	0.156	0.246	0.154	246.4										
2034	0.227	0.162	0.256	0.160	252.5										
2035	0.236	0.168	0.266	0.167	258.8										
2036	0.245	0.175	0.277	0.173	265.3										
2037	0.255	0.182	0.288	0.180	271.9										
2038	0.265	0.189	0.299	0.187	278.7										
2039	0.276	0.197	0.311	0.195	285.7										
2040	0.287	0.205	0.324	0.203	292.8										
Levelized															
(2008-2040)	0.145	0.105	0.159	0.103	162.3	0.004	0.003	0.008	0.003	11.5	0.007	0.006	0.013	0.006	14.5
(2009-2040)	0.147	0.106	0.162	0.105	172.3	0.004	0.003	0.007	0.003	11.9	0.007	0.006	0.014	0.006	15.4
5 years (2008-12)	0.106	0.078	0.106	0.075	61.0	0.027	0.023	0.051	0.022	66.8	0.026	0.023	0.051	0.022	28.8
10 years (2008-17)	0.108	0.079	0.113	0.078	103.8	0.013	0.011	0.025	0.011	38.0	0.015	0.013	0.028	0.012	30.6
15 years (2008-22)	0.114	0.083	0.121	0.082	123.1	0.009	0.008	0.017	0.007	25.4	0.011	0.009	0.021	0.009	22.6
PV to 2008						0.124	0.107	0.236	0.103	326.2	0.121	0.104	0.231	0.100	250.0
PV to 2009											0.127	0.109	0.242	0.105	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in

2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																	
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.084	0.061	0.086	0.064		0.150											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.094	0.069	0.088	0.066		0.156	40.5	0.015	0.013	0.029	0.013	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.088	0.067	0.088	0.063		0.156	45.2	0.044	0.038	0.084	0.037	-	0.015	0.013	0.029	0.013	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.075	0.088	0.063	0.088	0.060	67	0.167	19.0	0.041	0.035	0.078	0.034	72	0.044	0.038	0.084	0.037	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.138	0.084	0.060	0.087	0.059	114	0.181		0.025	0.021	0.048	0.021	140	0.041	0.035	0.078	0.034	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.158	0.084	0.062	0.089	0.062	114	0.189						90	0.025	0.021	0.048	0.021	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.172	0.079	0.057	0.086	0.057	114	0.191						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.176	0.081	0.058	0.085	0.058	114	0.187											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.181	0.080	0.058	0.089	0.057	114	0.176											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.185	0.083	0.059	0.090	0.061	114	0.155											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.190	0.085	0.061	0.092	0.060	114	0.127											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.195	0.084	0.061	0.092	0.062	114	0.092											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.200	0.084	0.060	0.094	0.061	114	0.049											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.205	0.085	0.062	0.095	0.061	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.210	0.087	0.063	0.099	0.062	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.215	0.089	0.064	0.101	0.063	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.220	0.090	0.065	0.102	0.064	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.226	0.092	0.065	0.103	0.065	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.232	0.093	0.066	0.105	0.066	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.237	0.094	0.067	0.107	0.067	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.243	0.096	0.068	0.108	0.068	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.249	0.097	0.069	0.110	0.069	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.256	0.098	0.070	0.111	0.070	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.262	0.100	0.071	0.113	0.071	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.268	0.101	0.072	0.114	0.072	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.275	0.103	0.073	0.116	0.073	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.282	0.104	0.074	0.118	0.074	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.289	0.106	0.076	0.120	0.075	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.296	0.107	0.077	0.121	0.076	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.304	0.109	0.078	0.123	0.077	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.311	0.110	0.079	0.125	0.078	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.319	0.112	0.080	0.127	0.079	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.327	0.114	0.081	0.128	0.080	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.335	0.115	0.082	0.130	0.082	114												
Levelized																								
(2008-2040)	0.034	0.034	0.038	0.037	39.7	29.8	0.201																	
(2009-2040)	0.034	0.034	0.038	0.037	40.7	30.5	0.205																	
5 years (2008-12)	0.037	0.037	0.041	0.040	20.0	15.0	0.016																	
10 years (2008-17)	0.035	0.034	0.039	0.038	26.0	19.5	0.093																	
15 years (2008-22)	0.033	0.032	0.037	0.036	29.4	22.0	0.128																	
PV to 2008																								
PV to 2009																								

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-A l Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S cludes June through September; Winter is all other months.
Syn Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: **Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	57%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Southeast Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.093	0.068	0.094	0.070	-										
2008	0.107	0.079	0.098	0.074	-	0.019	0.014	0.032	0.013	-	-	-	-	-	-
2009	0.102	0.078	0.101	0.071	-	0.055	0.043	0.095	0.039	-	0.019	0.015	0.033	0.013	-
2010	0.103	0.076	0.104	0.071	65.1	0.052	0.041	0.090	0.036	78	0.056	0.044	0.097	0.040	-
2011	0.101	0.074	0.104	0.070	120.4	0.033	0.025	0.056	0.023	155	0.053	0.042	0.092	0.037	-
2012	0.104	0.078	0.109	0.075	138.1					102	0.033	0.026	0.058	0.023	158
2013	0.101	0.074	0.106	0.073	150.3					46					104
2014	0.107	0.076	0.110	0.076	154.1										48
2015	0.108	0.078	0.118	0.076	158.0										
2016	0.112	0.082	0.121	0.081	161.9										
2017	0.119	0.086	0.128	0.085	165.9										
2018	0.120	0.087	0.130	0.087	170.1										
2019	0.122	0.088	0.137	0.088	174.3										
2020	0.125	0.093	0.140	0.091	178.7										
2021	0.131	0.095	0.151	0.094	183.2										
2022	0.140	0.099	0.157	0.099	187.8										
2023	0.145	0.103	0.163	0.103	192.4										
2024	0.151	0.107	0.170	0.107	197.3										
2025	0.157	0.111	0.176	0.112	202.2										
2026	0.163	0.116	0.184	0.116	207.2										
2027	0.170	0.120	0.191	0.121	212.4										
2028	0.177	0.125	0.198	0.126	217.7										
2029	0.184	0.130	0.206	0.131	223.2										
2030	0.191	0.135	0.215	0.136	228.8										
2031	0.198	0.141	0.223	0.141	234.5										
2032	0.206	0.146	0.232	0.147	240.3										
2033	0.215	0.152	0.241	0.153	246.4										
2034	0.223	0.158	0.251	0.159	252.5										
2035	0.232	0.165	0.261	0.165	258.8										
2036	0.241	0.171	0.271	0.172	265.3										
2037	0.251	0.178	0.282	0.179	271.9										
2038	0.261	0.185	0.293	0.186	278.7										
2039	0.271	0.192	0.305	0.193	285.7										
2040	0.282	0.200	0.317	0.201	292.8										
Levelized															
(2008-2040)	0.142	0.102	0.155	0.101	162.3	0.009	0.007	0.015	0.006	18.9	0.008	0.007	0.014	0.006	14.5
(2009-2040)	0.144	0.104	0.158	0.103	172.3	0.008	0.006	0.014	0.006	20.1	0.009	0.007	0.015	0.006	15.4
5 years (2008-12)	0.104	0.077	0.103	0.072	61.0	0.032	0.025	0.055	0.022	63.4	0.031	0.025	0.054	0.022	28.8
10 years (2008-17)	0.106	0.078	0.109	0.075	103.8	0.018	0.014	0.031	0.013	39.9	0.018	0.014	0.030	0.012	30.6
15 years (2008-22)	0.111	0.082	0.118	0.079	123.1	0.013	0.010	0.023	0.009	29.5	0.013	0.010	0.022	0.009	22.6
PV to 2008						0.147	0.115	0.253	0.103	326.2	0.144	0.112	0.247	0.100	250.0
PV to 2009											0.150	0.118	0.259	0.105	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.083	0.061	0.084	0.062		0.150											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.094	0.069	0.086	0.064		0.156	40.5	0.018	0.014	0.031	0.013	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.087	0.066	0.086	0.060		0.156	45.2	0.052	0.041	0.090	0.037	-	0.018	0.014	0.031	0.013	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.084	0.086	0.063	0.086	0.058	67	0.167	19.0	0.048	0.038	0.084	0.034	72	0.052	0.041	0.090	0.037	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.155	0.081	0.059	0.084	0.056	114	0.181		0.030	0.023	0.051	0.021	140	0.048	0.038	0.084	0.034	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.177	0.082	0.061	0.085	0.058	114	0.189						90	0.030	0.023	0.051	0.021	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.193	0.077	0.056	0.081	0.055	114	0.191						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.198	0.080	0.056	0.082	0.056	114	0.187											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.203	0.079	0.057	0.086	0.055	114	0.176											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.208	0.080	0.058	0.087	0.058	114	0.155											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.213	0.083	0.060	0.090	0.059	114	0.127											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.218	0.082	0.060	0.089	0.059	114	0.092											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.224	0.082	0.059	0.092	0.059	114	0.049											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.230	0.083	0.061	0.092	0.060	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.235	0.084	0.061	0.097	0.061	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.241	0.088	0.062	0.099	0.062	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.247	0.089	0.063	0.100	0.063	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.253	0.090	0.064	0.101	0.064	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.260	0.091	0.065	0.103	0.065	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.266	0.093	0.066	0.104	0.066	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.273	0.094	0.067	0.106	0.067	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.280	0.096	0.068	0.107	0.068	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.287	0.097	0.069	0.109	0.069	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.294	0.098	0.070	0.111	0.070	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.301	0.100	0.071	0.112	0.071	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.309	0.101	0.072	0.114	0.072	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.316	0.103	0.073	0.115	0.073	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.324	0.104	0.074	0.117	0.074	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.332	0.106	0.075	0.119	0.075	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.341	0.107	0.076	0.121	0.076	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.349	0.109	0.077	0.122	0.077	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.358	0.110	0.078	0.124	0.079	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.367	0.112	0.079	0.126	0.080	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.376	0.114	0.081	0.128	0.081	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.225																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.229																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.017																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.104																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.144																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-Al Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Si ludes June through September; Winter is all other months.
Syna nergy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: **Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	West-Central Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.095	0.070	0.096	0.073	-										
2008	0.108	0.082	0.100	0.078	-	0.016	0.012	0.027	0.010	-	-	-	-	-	-
2009	0.103	0.080	0.102	0.076	-	0.047	0.036	0.080	0.030	-	0.016	0.012	0.027	0.010	-
2010	0.105	0.078	0.105	0.073	65.1	0.045	0.034	0.077	0.029	78	0.048	0.037	0.082	0.031	-
2011	0.103	0.077	0.106	0.073	120.4	0.028	0.021	0.048	0.018	155	0.046	0.035	0.078	0.029	-
2012	0.106	0.080	0.110	0.078	138.1					102	0.029	0.022	0.049	0.018	158
2013	0.103	0.076	0.109	0.075	150.3					46					104
2014	0.109	0.078	0.112	0.079	154.1										48
2015	0.109	0.081	0.119	0.081	158.0										
2016	0.115	0.084	0.122	0.086	161.9										
2017	0.120	0.088	0.130	0.088	165.9										
2018	0.120	0.089	0.130	0.090	170.1										
2019	0.122	0.089	0.136	0.089	174.3										
2020	0.129	0.095	0.142	0.094	178.7										
2021	0.132	0.097	0.150	0.097	183.2										
2022	0.139	0.102	0.157	0.101	187.8										
2023	0.145	0.106	0.163	0.105	192.4										
2024	0.151	0.110	0.170	0.109	197.3										
2025	0.157	0.114	0.176	0.114	202.2										
2026	0.163	0.119	0.183	0.118	207.2										
2027	0.170	0.123	0.191	0.123	212.4										
2028	0.176	0.128	0.198	0.128	217.7										
2029	0.183	0.133	0.206	0.133	223.2										
2030	0.191	0.139	0.215	0.138	228.8										
2031	0.198	0.144	0.223	0.144	234.5										
2032	0.206	0.150	0.232	0.149	240.3										
2033	0.214	0.156	0.241	0.155	246.4										
2034	0.223	0.162	0.251	0.161	252.5										
2035	0.232	0.169	0.261	0.168	258.8										
2036	0.241	0.175	0.271	0.175	265.3										
2037	0.251	0.182	0.282	0.181	271.9										
2038	0.261	0.190	0.293	0.189	278.7										
2039	0.271	0.197	0.305	0.196	285.7										
2040	0.282	0.205	0.317	0.204	292.8										
Levelized															
(2008-2040)	0.143	0.105	0.155	0.104	162.3	0.007	0.006	0.012	0.005	18.9	0.007	0.005	0.012	0.005	14.5
(2009-2040)	0.145	0.107	0.159	0.105	172.3	0.007	0.005	0.012	0.004	20.1	0.008	0.006	0.013	0.005	15.4
5 years (2008-12)	0.105	0.080	0.104	0.075	61.0	0.027	0.021	0.047	0.018	63.4	0.027	0.021	0.046	0.017	28.8
10 years (2008-17)	0.108	0.080	0.110	0.078	103.8	0.015	0.012	0.026	0.010	39.9	0.015	0.011	0.026	0.010	30.6
15 years (2008-22)	0.113	0.084	0.119	0.082	123.1	0.011	0.009	0.019	0.007	29.5	0.011	0.008	0.019	0.007	22.6
PV to 2008						0.125	0.096	0.214	0.080	326.2	0.123	0.094	0.210	0.078	250.0
PV to 2009											0.128	0.098	0.220	0.082	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.085	0.062	0.086	0.065		0.150											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.095	0.071	0.087	0.067		0.156	40.5	0.015	0.012	0.026	0.010	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.087	0.068	0.086	0.064		0.156	45.2	0.045	0.034	0.076	0.029	-	0.015	0.012	0.026	0.010	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.079	0.087	0.064	0.087	0.060	67	0.167	19.0	0.042	0.032	0.071	0.027	72	0.045	0.034	0.076	0.029	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.147	0.083	0.062	0.086	0.058	114	0.181		0.025	0.019	0.043	0.016	140	0.042	0.032	0.071	0.027	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.168	0.083	0.063	0.087	0.061	114	0.189						90	0.025	0.019	0.043	0.016	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.183	0.079	0.058	0.083	0.057	114	0.191						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.188	0.082	0.058	0.084	0.059	114	0.187											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.193	0.080	0.058	0.087	0.058	114	0.176											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.197	0.082	0.060	0.087	0.061	114	0.155											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.202	0.084	0.062	0.091	0.061	114	0.127											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.207	0.082	0.061	0.089	0.061	114	0.092											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.213	0.082	0.060	0.091	0.060	114	0.049											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.218	0.085	0.062	0.093	0.062	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.223	0.085	0.062	0.097	0.062	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.229	0.088	0.064	0.098	0.063	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.235	0.089	0.065	0.100	0.064	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.241	0.090	0.066	0.101	0.065	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.247	0.091	0.067	0.103	0.066	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.253	0.093	0.067	0.104	0.067	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.259	0.094	0.068	0.106	0.068	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.266	0.095	0.069	0.107	0.069	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.272	0.097	0.070	0.109	0.070	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.279	0.098	0.071	0.111	0.071	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.286	0.100	0.073	0.112	0.072	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.293	0.101	0.074	0.114	0.073	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.300	0.103	0.075	0.115	0.074	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.308	0.104	0.076	0.117	0.075	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.316	0.106	0.077	0.119	0.076	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.324	0.107	0.078	0.120	0.078	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.332	0.109	0.079	0.122	0.079	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.340	0.110	0.080	0.124	0.080	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.348	0.112	0.081	0.126	0.081	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.357	0.113	0.083	0.128	0.082	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.214																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.218																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.017																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.099																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.137																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-Al Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Si ludes June through September; Winter is all other months.
Syn nergy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	59%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Massachusetts outside of Northeast Mass					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.094	0.069	0.095	0.072	-										
2008	0.108	0.081	0.099	0.076	-	0.017	0.013	0.029	0.011	-	-	-	-	-	-
2009	0.102	0.079	0.101	0.073	-	0.050	0.039	0.087	0.034	-	0.017	0.013	0.030	0.011	-
2010	0.104	0.077	0.105	0.072	65.1	0.048	0.037	0.083	0.032	78	0.052	0.040	0.089	0.034	-
2011	0.102	0.076	0.105	0.071	120.4	0.030	0.023	0.052	0.020	155	0.049	0.038	0.085	0.033	-
2012	0.105	0.079	0.110	0.076	138.1					102	0.031	0.024	0.053	0.020	158
2013	0.102	0.075	0.107	0.074	150.3					46					104
2014	0.108	0.077	0.111	0.078	154.1										48
2015	0.109	0.079	0.118	0.079	158.0										
2016	0.113	0.083	0.122	0.084	161.9										
2017	0.120	0.087	0.129	0.086	165.9										
2018	0.120	0.088	0.130	0.088	170.1										
2019	0.122	0.088	0.136	0.089	174.3										
2020	0.127	0.094	0.141	0.092	178.7										
2021	0.132	0.096	0.151	0.095	183.2										
2022	0.140	0.100	0.157	0.100	187.8										
2023	0.145	0.104	0.163	0.104	192.4										
2024	0.151	0.108	0.170	0.108	197.3										
2025	0.157	0.113	0.176	0.113	202.2										
2026	0.163	0.117	0.183	0.117	207.2										
2027	0.170	0.122	0.191	0.122	212.4										
2028	0.176	0.127	0.198	0.127	217.7										
2029	0.183	0.132	0.206	0.132	223.2										
2030	0.191	0.137	0.215	0.137	228.8										
2031	0.198	0.143	0.223	0.142	234.5										
2032	0.206	0.148	0.232	0.148	240.3										
2033	0.214	0.154	0.241	0.154	246.4										
2034	0.223	0.160	0.251	0.160	252.5										
2035	0.232	0.167	0.261	0.167	258.8										
2036	0.241	0.173	0.271	0.173	265.3										
2037	0.251	0.180	0.282	0.180	271.9										
2038	0.261	0.187	0.293	0.187	278.7										
2039	0.271	0.195	0.305	0.195	285.7										
2040	0.282	0.203	0.317	0.202	292.8										
Levelized															
(2008-2040)	0.142	0.104	0.155	0.102	162.3	0.008	0.006	0.014	0.005	18.9	0.008	0.006	0.013	0.005	14.5
(2009-2040)	0.145	0.105	0.159	0.104	172.3	0.007	0.006	0.013	0.005	20.1	0.008	0.006	0.014	0.005	15.4
5 years (2008-12)	0.104	0.078	0.104	0.074	61.0	0.030	0.023	0.051	0.020	63.4	0.029	0.022	0.050	0.019	28.8
10 years (2008-17)	0.107	0.079	0.110	0.076	103.8	0.017	0.013	0.028	0.011	39.9	0.016	0.012	0.028	0.011	30.6
15 years (2008-22)	0.112	0.083	0.118	0.081	123.1	0.012	0.009	0.021	0.008	29.5	0.012	0.009	0.021	0.008	22.6
PV to 2008						0.135	0.104	0.233	0.090	326.2	0.132	0.101	0.228	0.088	250.0
PV to 2009											0.138	0.106	0.239	0.092	262.0

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.084	0.061	0.085	0.064		0.150											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.094	0.070	0.086	0.066		0.156	40.5	0.017	0.013	0.028	0.011	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.087	0.067	0.086	0.062		0.156	45.2	0.048	0.037	0.083	0.032	-	0.017	0.013	0.028	0.011	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.081	0.086	0.064	0.087	0.059	67	0.167	19.0	0.045	0.034	0.077	0.030	72	0.048	0.037	0.083	0.032	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.151	0.082	0.060	0.085	0.057	114	0.181		0.027	0.021	0.047	0.018	140	0.045	0.034	0.077	0.030	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.173	0.083	0.062	0.086	0.059	114	0.189						90	0.027	0.021	0.047	0.018	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.188	0.078	0.057	0.082	0.056	114	0.191						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.193	0.081	0.057	0.083	0.057	114	0.187											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.198	0.079	0.058	0.087	0.057	114	0.176											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.203	0.081	0.059	0.087	0.059	114	0.155											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.208	0.084	0.061	0.090	0.060	114	0.127											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.213	0.082	0.060	0.089	0.060	114	0.092											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.218	0.082	0.059	0.092	0.059	114	0.049											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.224	0.084	0.062	0.093	0.061	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.229	0.085	0.062	0.097	0.061	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.235	0.088	0.063	0.099	0.063	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.241	0.089	0.064	0.100	0.064	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.247	0.090	0.065	0.101	0.065	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.253	0.091	0.066	0.103	0.066	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.259	0.093	0.067	0.104	0.067	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.266	0.094	0.068	0.106	0.068	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.272	0.095	0.069	0.107	0.069	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.279	0.097	0.070	0.109	0.070	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.286	0.098	0.071	0.111	0.071	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.293	0.100	0.072	0.112	0.072	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.301	0.101	0.073	0.114	0.073	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.308	0.103	0.074	0.115	0.074	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.316	0.104	0.075	0.117	0.075	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.324	0.106	0.076	0.119	0.076	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.332	0.107	0.077	0.121	0.077	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.340	0.109	0.078	0.122	0.078	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.349	0.110	0.079	0.124	0.079	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.357	0.112	0.080	0.126	0.080	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.366	0.113	0.082	0.128	0.081	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.219																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.223																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.017																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.101																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.140																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Southwest Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.100	0.073	0.105	0.076	-										
2008	0.114	0.085	0.110	0.083	-	0.017	0.014	0.034	0.017	-	-	-	-	-	-
2009	0.110	0.084	0.113	0.078	-	0.051	0.041	0.105	0.053	-	0.017	0.014	0.035	0.017	-
2010	0.110	0.082	0.113	0.077	65.1	0.050	0.040	0.105	0.053	78	0.052	0.042	0.108	0.054	-
2011	0.108	0.079	0.115	0.077	120.4	0.031	0.025	0.065	0.033	155	0.051	0.041	0.107	0.055	-
2012	0.111	0.082	0.122	0.080	138.1					102	0.032	0.026	0.067	0.034	158
2013	0.109	0.078	0.117	0.077	150.3					46					104
2014	0.113	0.079	0.119	0.079	154.1										48
2015	0.113	0.082	0.122	0.080	158.0										
2016	0.117	0.086	0.128	0.084	161.9										
2017	0.125	0.090	0.137	0.089	165.9										
2018	0.126	0.093	0.137	0.092	170.1										
2019	0.127	0.092	0.142	0.092	174.3										
2020	0.134	0.099	0.150	0.096	178.7										
2021	0.137	0.101	0.157	0.099	183.2										
2022	0.146	0.104	0.166	0.104	187.8										
2023	0.151	0.108	0.172	0.108	192.4										
2024	0.157	0.113	0.179	0.112	197.3										
2025	0.164	0.117	0.186	0.117	202.2										
2026	0.170	0.122	0.194	0.122	207.2										
2027	0.177	0.127	0.201	0.126	212.4										
2028	0.184	0.132	0.209	0.131	217.7										
2029	0.191	0.137	0.218	0.137	223.2										
2030	0.199	0.143	0.227	0.142	228.8										
2031	0.207	0.148	0.236	0.148	234.5										
2032	0.215	0.154	0.245	0.154	240.3										
2033	0.224	0.160	0.255	0.160	246.4										
2034	0.233	0.167	0.265	0.166	252.5										
2035	0.242	0.173	0.275	0.173	258.8										
2036	0.251	0.180	0.286	0.180	265.3										
2037	0.262	0.187	0.298	0.187	271.9										
2038	0.272	0.195	0.310	0.194	278.7										
2039	0.283	0.203	0.322	0.202	285.7										
2040	0.294	0.211	0.335	0.210	292.8										
Levelized															
(2008-2040)	0.149	0.108	0.165	0.107	162.3	0.005	0.004	0.009	0.005	11.5	0.008	0.006	0.016	0.008	14.5
(2009-2040)	0.151	0.110	0.168	0.108	172.3	0.004	0.003	0.009	0.004	11.9	0.008	0.007	0.017	0.009	15.4
5 years (2008-12)	0.111	0.083	0.114	0.079	61.0	0.030	0.024	0.062	0.031	66.8	0.030	0.024	0.061	0.031	28.8
10 years (2008-17)	0.113	0.083	0.119	0.080	103.8	0.015	0.012	0.031	0.016	38.0	0.017	0.013	0.034	0.017	30.6
15 years (2008-22)	0.118	0.086	0.127	0.084	123.1	0.010	0.008	0.021	0.010	25.4	0.012	0.010	0.025	0.013	22.6
PV to 2008						0.138	0.112	0.286	0.145	326.2	0.135	0.109	0.280	0.142	250.0
PV to 2009											0.142	0.114	0.294	0.149	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
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FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																	
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and Inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.089	0.065	0.094	0.068		0.175											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.099	0.073	0.095	0.071		0.222	40.5	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.093	0.070	0.096	0.065		0.233	45.2	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.079	0.090	0.067	0.093	0.063	67	0.233	19.0	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.147	0.087	0.063	0.092	0.061	114	0.211		0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.168	0.087	0.064	0.096	0.062	114	0.189						90	0.028	0.023	0.059	0.030	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.183	0.083	0.059	0.090	0.059	114	0.167						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.187	0.085	0.059	0.090	0.059	114	0.145											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.192	0.083	0.060	0.090	0.058	114	0.123											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.197	0.085	0.061	0.093	0.060	114	0.099											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.202	0.088	0.063	0.097	0.063	114	0.074											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.207	0.087	0.064	0.095	0.063	114	0.049											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.212	0.086	0.062	0.095	0.062	114	0.025											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.217	0.088	0.065	0.099	0.063	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.223	0.088	0.065	0.101	0.063	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.228	0.091	0.065	0.104	0.065	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.234	0.093	0.066	0.106	0.066	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.240	0.094	0.067	0.107	0.067	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.246	0.095	0.068	0.109	0.068	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.252	0.097	0.069	0.110	0.069	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.258	0.098	0.070	0.112	0.070	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.265	0.100	0.071	0.113	0.071	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.271	0.101	0.072	0.115	0.072	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.278	0.102	0.073	0.117	0.073	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.285	0.104	0.075	0.118	0.074	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.292	0.105	0.076	0.120	0.075	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.300	0.107	0.077	0.122	0.076	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.307	0.109	0.078	0.124	0.078	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.315	0.110	0.079	0.125	0.079	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.323	0.112	0.080	0.127	0.080	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.331	0.113	0.081	0.129	0.081	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.339	0.115	0.082	0.131	0.082	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.348	0.117	0.084	0.133	0.083	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.356	0.118	0.085	0.135	0.085	114												
Levelized																								
(2008-2040)	0.034	0.034	0.038	0.037	39.7	29.8	0.213																	
(2009-2040)	0.034	0.034	0.038	0.037	40.7	30.5	0.217																	
5 years (2008-12)	0.037	0.037	0.041	0.040	20.0	15.0	0.016																	
10 years (2008-17)	0.035	0.034	0.039	0.038	26.0	19.5	0.099																	
15 years (2008-22)	0.033	0.032	0.037	0.036	29.4	22.0	0.136																	
PV to 2008																								
PV to 2009																								

Notes:
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-A Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S cludes June through September; Winter is all other months.
Syn Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	59%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Norwalk-Stamford					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.104	0.075	0.116	0.078	-										
2008	0.119	0.087	0.121	0.085	-	0.017	0.014	0.034	0.017	-	-	-	-	-	-
2009	0.114	0.086	0.124	0.080	-	0.051	0.041	0.105	0.053	-	0.017	0.014	0.035	0.017	-
2010	0.110	0.082	0.118	0.077	65.1	0.050	0.040	0.105	0.053	78	0.052	0.042	0.108	0.054	-
2011	0.108	0.079	0.120	0.077	120.4	0.031	0.025	0.065	0.033	155	0.051	0.041	0.107	0.055	-
2012	0.111	0.082	0.128	0.080	138.1					102	0.032	0.026	0.067	0.034	158
2013	0.109	0.078	0.123	0.077	150.3					46					104
2014	0.113	0.079	0.125	0.079	154.1										48
2015	0.113	0.082	0.128	0.080	158.0										
2016	0.117	0.086	0.135	0.084	161.9										
2017	0.125	0.090	0.144	0.089	165.9										
2018	0.126	0.093	0.144	0.092	170.1										
2019	0.127	0.092	0.149	0.092	174.3										
2020	0.134	0.099	0.158	0.096	178.7										
2021	0.137	0.101	0.165	0.099	183.2										
2022	0.146	0.104	0.174	0.104	187.8										
2023	0.151	0.108	0.181	0.108	192.4										
2024	0.157	0.113	0.188	0.112	197.3										
2025	0.164	0.117	0.196	0.117	202.2										
2026	0.170	0.122	0.203	0.122	207.2										
2027	0.177	0.127	0.212	0.126	212.4										
2028	0.184	0.132	0.220	0.131	217.7										
2029	0.191	0.137	0.229	0.137	223.2										
2030	0.199	0.143	0.238	0.142	228.8										
2031	0.207	0.148	0.247	0.148	234.5										
2032	0.215	0.154	0.257	0.154	240.3										
2033	0.224	0.160	0.267	0.160	246.4										
2034	0.233	0.167	0.278	0.166	252.5										
2035	0.242	0.173	0.289	0.173	258.8										
2036	0.251	0.180	0.301	0.180	265.3										
2037	0.262	0.187	0.313	0.187	271.9										
2038	0.272	0.195	0.325	0.194	278.7										
2039	0.283	0.203	0.338	0.202	285.7										
2040	0.294	0.211	0.352	0.210	292.8										
Levelized															
(2008-2040)	0.150	0.108	0.174	0.107	162.3	0.008	0.006	0.017	0.008	18.9	0.008	0.006	0.016	0.008	14.5
(2009-2040)	0.152	0.110	0.177	0.108	172.3	0.007	0.006	0.016	0.008	20.1	0.008	0.007	0.017	0.009	15.4
5 years (2008-12)	0.113	0.083	0.122	0.080	61.0	0.030	0.024	0.063	0.032	63.4	0.030	0.024	0.061	0.031	28.8
10 years (2008-17)	0.114	0.083	0.126	0.081	103.8	0.017	0.014	0.035	0.018	39.9	0.017	0.013	0.034	0.017	30.6
15 years (2008-22)	0.119	0.087	0.134	0.085	123.1	0.013	0.010	0.026	0.013	29.5	0.012	0.010	0.025	0.013	22.6
PV to 2008						0.138	0.112	0.286	0.145	326.2	0.135	0.109	0.280	0.142	250.0
PV to 2009											0.142	0.114	0.294	0.149	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.093	0.066	0.104	0.069		0.175											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.103	0.075	0.105	0.073		0.222	40.5	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.096	0.072	0.105	0.067		0.233	45.2	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.081	0.090	0.067	0.097	0.063	67	0.233	19.0	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.149	0.087	0.063	0.097	0.061	114	0.211		0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.171	0.087	0.064	0.101	0.062	114	0.189						90	0.028	0.023	0.059	0.030	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.187	0.083	0.059	0.095	0.059	114	0.167						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.191	0.085	0.059	0.094	0.059	114	0.145											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.196	0.083	0.060	0.095	0.058	114	0.123											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.201	0.085	0.061	0.097	0.060	114	0.099											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.206	0.088	0.063	0.101	0.063	114	0.074											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.211	0.087	0.064	0.099	0.063	114	0.049											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.216	0.086	0.062	0.100	0.062	114	0.025											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.222	0.088	0.065	0.104	0.063	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.227	0.088	0.065	0.106	0.063	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.233	0.091	0.065	0.109	0.065	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.239	0.093	0.066	0.111	0.066	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.245	0.094	0.067	0.112	0.067	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.251	0.095	0.068	0.114	0.068	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.257	0.097	0.069	0.116	0.069	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.264	0.098	0.070	0.117	0.070	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.270	0.100	0.071	0.119	0.071	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.277	0.101	0.072	0.121	0.072	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.284	0.102	0.073	0.123	0.073	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.291	0.104	0.075	0.124	0.074	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.298	0.105	0.076	0.126	0.075	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.306	0.107	0.077	0.128	0.076	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.313	0.109	0.078	0.130	0.078	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.321	0.110	0.079	0.132	0.079	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.329	0.112	0.080	0.134	0.080	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.338	0.113	0.081	0.136	0.081	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.346	0.115	0.082	0.137	0.082	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.355	0.117	0.084	0.139	0.083	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.363	0.118	0.085	0.142	0.085	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.218																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.222																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.017																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.101																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.139																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-A[illegible] Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S[illegible]cludes June through September; Winter is all other months.
Sy[illegible]nergy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: **Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Southwest Connecticut except Norwalk-Stamford					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.098	0.073	0.100	0.076	-										
2008	0.112	0.084	0.104	0.082	-	0.017	0.014	0.034	0.017	-	-	-	-	-	-
2009	0.108	0.083	0.107	0.077	-	0.051	0.041	0.105	0.053	-	0.017	0.014	0.035	0.017	-
2010	0.110	0.082	0.110	0.077	65.1	0.050	0.040	0.105	0.053	78	0.052	0.042	0.108	0.054	-
2011	0.108	0.079	0.112	0.077	120.4	0.031	0.025	0.065	0.033	155	0.051	0.041	0.107	0.055	-
2012	0.111	0.082	0.119	0.080	138.1					102	0.032	0.026	0.067	0.034	158
2013	0.109	0.078	0.114	0.077	150.3					46					104
2014	0.113	0.079	0.116	0.079	154.1										48
2015	0.113	0.082	0.119	0.080	158.0										
2016	0.117	0.086	0.125	0.084	161.9										
2017	0.125	0.090	0.133	0.089	165.9										
2018	0.126	0.093	0.134	0.092	170.1										
2019	0.127	0.092	0.138	0.092	174.3										
2020	0.134	0.099	0.146	0.096	178.7										
2021	0.137	0.101	0.153	0.099	183.2										
2022	0.146	0.104	0.161	0.104	187.8										
2023	0.151	0.108	0.168	0.108	192.4										
2024	0.157	0.113	0.174	0.112	197.3										
2025	0.164	0.117	0.181	0.117	202.2										
2026	0.170	0.122	0.189	0.122	207.2										
2027	0.177	0.127	0.196	0.126	212.4										
2028	0.184	0.132	0.204	0.131	217.7										
2029	0.191	0.137	0.212	0.137	223.2										
2030	0.199	0.143	0.220	0.142	228.8										
2031	0.207	0.148	0.229	0.148	234.5										
2032	0.215	0.154	0.238	0.154	240.3										
2033	0.224	0.160	0.248	0.160	246.4										
2034	0.233	0.167	0.258	0.166	252.5										
2035	0.242	0.173	0.268	0.173	258.8										
2036	0.251	0.180	0.279	0.180	265.3										
2037	0.262	0.187	0.290	0.187	271.9										
2038	0.272	0.195	0.301	0.194	278.7										
2039	0.283	0.203	0.313	0.202	285.7										
2040	0.294	0.211	0.326	0.210	292.8										
Levelized															
(2008-2040)	0.149	0.108	0.160	0.107	162.3	0.008	0.006	0.017	0.008	18.9	0.008	0.006	0.016	0.008	14.5
(2009-2040)	0.151	0.110	0.164	0.108	172.3	0.007	0.006	0.016	0.008	20.1	0.008	0.007	0.017	0.009	15.4
5 years (2008-12)	0.110	0.082	0.110	0.079	61.0	0.030	0.024	0.063	0.032	63.4	0.030	0.024	0.061	0.031	28.8
10 years (2008-17)	0.112	0.082	0.115	0.080	103.8	0.017	0.014	0.035	0.018	39.9	0.017	0.013	0.034	0.017	30.6
15 years (2008-22)	0.118	0.086	0.123	0.084	123.1	0.013	0.010	0.026	0.013	29.5	0.012	0.010	0.025	0.013	22.6
PV to 2008						0.138	0.112	0.286	0.145	326.2	0.135	0.109	0.280	0.142	250.0
PV to 2009											0.142	0.114	0.294	0.149	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-All Avoided Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-Summer includes June through September; Winter is all other months.
Synapse Energy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in
2010-11 60%
2011-12 80%
2012-13 100%
2013-14 100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																	
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.088	0.064	0.089	0.067		0.175											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.097	0.073	0.090	0.071		0.222	40.5	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.091	0.070	0.090	0.065		0.233	45.2	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.078	0.090	0.067	0.090	0.063	67	0.233	19.0	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.145	0.087	0.063	0.090	0.061	114	0.211		0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.166	0.087	0.064	0.093	0.062	114	0.189						90	0.028	0.023	0.059	0.030	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.181	0.083	0.059	0.088	0.059	114	0.167						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.186	0.085	0.059	0.087	0.059	114	0.145											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.190	0.083	0.060	0.088	0.058	114	0.123											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.195	0.085	0.061	0.090	0.060	114	0.099											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.200	0.088	0.063	0.094	0.063	114	0.074											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.205	0.087	0.064	0.092	0.063	114	0.049											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.210	0.086	0.062	0.093	0.062	114	0.025											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.215	0.088	0.065	0.097	0.063	114	0.000											
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.221	0.088	0.065	0.098	0.063	114	0.000											
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.226	0.091	0.065	0.101	0.065	114	0.000											
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.232	0.093	0.066	0.103	0.066	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.238	0.094	0.067	0.104	0.067	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.244	0.095	0.068	0.106	0.068	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.250	0.097	0.069	0.107	0.069	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.256	0.098	0.070	0.109	0.070	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.262	0.100	0.071	0.110	0.071	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.269	0.101	0.072	0.112	0.072	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.276	0.102	0.073	0.114	0.073	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.282	0.104	0.075	0.115	0.074	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.289	0.105	0.076	0.117	0.075	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.297	0.107	0.077	0.119	0.076	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.304	0.109	0.078	0.120	0.078	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.312	0.110	0.079	0.122	0.079	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.320	0.112	0.080	0.124	0.080	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.327	0.113	0.081	0.126	0.081	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.336	0.115	0.082	0.127	0.082	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.344	0.117	0.084	0.129	0.083	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.353	0.118	0.085	0.131	0.085	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.211																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.215																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.016																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.098																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.135																	
PV to 2008																								
PV to 2009																								

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-A[illegible] Costs are in Nominal$; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S[illegible]cludes June through September; Winter is all other months.
Syn[illegible]nergy Economics – AESC 2007

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: **Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Inflation	2.5%
Retail Adder	10%
Nominal Discount Rate	4.8%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Wholesale Power Price, Nominal Dollars

	Connecticut except Southwest Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.099	0.072	0.104	0.075	-										
2008	0.113	0.084	0.108	0.082	-	0.017	0.014	0.034	0.017	-	-	-	-	-	-
2009	0.108	0.083	0.111	0.076	-	0.051	0.041	0.105	0.053	-	0.017	0.014	0.035	0.017	-
2010	0.108	0.080	0.111	0.076	65.1	0.050	0.040	0.105	0.053	78	0.052	0.042	0.108	0.054	-
2011	0.106	0.078	0.112	0.075	120.4	0.031	0.025	0.065	0.033	155	0.051	0.041	0.107	0.055	-
2012	0.110	0.081	0.119	0.078	138.1					102	0.032	0.026	0.067	0.034	158
2013	0.107	0.076	0.116	0.075	150.3					46					104
2014	0.111	0.078	0.117	0.078	154.1										48
2015	0.111	0.080	0.121	0.079	158.0										
2016	0.115	0.084	0.126	0.083	161.9										
2017	0.123	0.089	0.134	0.088	165.9										
2018	0.124	0.091	0.135	0.090	170.1										
2019	0.125	0.091	0.140	0.090	174.3										
2020	0.131	0.097	0.148	0.094	178.7										
2021	0.135	0.099	0.153	0.097	183.2										
2022	0.144	0.103	0.162	0.102	187.8										
2023	0.149	0.107	0.169	0.106	192.4										
2024	0.155	0.112	0.176	0.111	197.3										
2025	0.161	0.116	0.183	0.115	202.2										
2026	0.168	0.121	0.190	0.120	207.2										
2027	0.174	0.125	0.197	0.124	212.4										
2028	0.181	0.130	0.205	0.129	217.7										
2029	0.189	0.136	0.214	0.134	223.2										
2030	0.196	0.141	0.222	0.140	228.8										
2031	0.204	0.147	0.231	0.145	234.5										
2032	0.212	0.153	0.240	0.151	240.3										
2033	0.221	0.159	0.250	0.157	246.4										
2034	0.229	0.165	0.260	0.163	252.5										
2035	0.239	0.172	0.270	0.170	258.8										
2036	0.248	0.178	0.281	0.177	265.3										
2037	0.258	0.186	0.292	0.184	271.9										
2038	0.268	0.193	0.304	0.191	278.7										
2039	0.279	0.201	0.316	0.199	285.7										
2040	0.290	0.209	0.328	0.207	292.8										
Levelized															
(2008-2040)	0.147	0.107	0.162	0.105	162.3	0.008	0.006	0.017	0.008	18.9	0.008	0.006	0.016	0.008	14.5
(2009-2040)	0.149	0.108	0.165	0.106	172.3	0.007	0.006	0.016	0.008	20.1	0.008	0.007	0.017	0.009	15.4
5 years (2008-12)	0.109	0.081	0.112	0.078	61.0	0.030	0.024	0.063	0.032	63.4	0.030	0.024	0.061	0.031	28.8
10 years (2008-17)	0.111	0.081	0.117	0.079	103.8	0.017	0.014	0.035	0.018	39.9	0.017	0.013	0.034	0.017	30.6
15 years (2008-22)	0.116	0.085	0.124	0.083	123.1	0.013	0.010	0.026	0.013	29.5	0.012	0.010	0.025	0.013	22.6
PV to 2008						0.138	0.112	0.286	0.145	326.2	0.135	0.109	0.280	0.142	250.0
PV to 2009											0.142	0.114	0.294	0.149	262.0

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.
2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

AESC Nominal Dollar Avoided Cost Results by Screening Zone

NOTE: Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

FCM phase-in

2010-11	60%
2011-12	80%
2012-13	100%
2013-14	100%

	Wholesale Power Price, Nominal Dollars							Inputs (Real 2007$)																	
	Additional CO2 Costs (see note below)				FCM Revenue (not an avoided cost; do not add to avoided costs)			Avoided Costs before Adders and inflation					REC Costs	ICAP	DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy		Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:																								
2007	0.037	0.036	0.041	0.040				0.088	0.064	0.092	0.066		0.175											
2008	0.038	0.037	0.042	0.041	9.5	7.2		0.098	0.072	0.093	0.071		0.222	40.5	0.017	0.013	0.033	0.016	-	-	-	-	-	-
2009	0.037	0.036	0.041	0.040	10.9	8.2		0.091	0.069	0.094	0.064		0.233	45.2	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-
2010	0.038	0.037	0.042	0.041	21.2	15.9	0.079	0.089	0.065	0.091	0.062	67	0.233	19.0	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-
2011	0.039	0.038	0.043	0.042	28.9	21.7	0.147	0.085	0.062	0.090	0.060	114	0.211		0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-
2012	0.035	0.034	0.039	0.038	29.6	22.2	0.168	0.086	0.063	0.094	0.060	114	0.189						90	0.028	0.023	0.059	0.030	140
2013	0.034	0.034	0.038	0.037	30.4	22.8	0.183	0.082	0.058	0.089	0.057	114	0.167						40					90
2014	0.034	0.033	0.037	0.036	31.1	23.3	0.187	0.084	0.059	0.088	0.058	114	0.145											40
2015	0.033	0.032	0.037	0.036	31.9	23.9	0.192	0.082	0.059	0.089	0.057	114	0.123											
2016	0.032	0.032	0.036	0.035	32.7	24.5	0.197	0.083	0.060	0.091	0.059	114	0.099											
2017	0.031	0.031	0.035	0.034	33.5	25.1	0.202	0.086	0.062	0.094	0.062	114	0.074											
2018	0.030	0.030	0.034	0.033	34.4	25.8	0.207	0.085	0.062	0.093	0.062	114	0.049											
2019	0.029	0.029	0.033	0.032	35.2	26.4	0.212	0.084	0.061	0.094	0.061	114	0.025											
2020	0.028	0.028	0.032	0.031	36.1	27.1	0.217	0.086	0.064	0.098	0.062	114												
2021	0.028	0.028	0.031	0.030	37.0	27.8	0.223	0.087	0.064	0.098	0.062	114												
2022	0.028	0.027	0.031	0.030	37.9	28.4	0.228	0.090	0.065	0.102	0.064	114												
2023	0.029	0.028	0.032	0.031	38.9	29.2	0.234	0.091	0.066	0.103	0.065	114												
2024	0.029	0.029	0.033	0.032	39.9	29.9	0.240	0.093	0.067	0.105	0.066	114												
2025	0.030	0.030	0.034	0.033	40.8	30.6	0.246	0.094	0.068	0.106	0.067	114												
2026	0.031	0.030	0.034	0.033	41.9	31.4	0.252	0.095	0.069	0.108	0.068	114												
2027	0.032	0.031	0.035	0.034	42.9	32.2	0.258	0.097	0.070	0.110	0.069	114												
2028	0.032	0.032	0.036	0.035	44.0	33.0	0.265	0.098	0.071	0.111	0.070	114												
2029	0.033	0.033	0.037	0.036	45.1	33.8	0.271	0.100	0.072	0.113	0.071	114												
2030	0.034	0.033	0.038	0.037	46.2	34.7	0.278	0.101	0.073	0.114	0.072	114												
2031	0.035	0.034	0.039	0.038	47.4	35.5	0.285	0.103	0.074	0.116	0.073	114												
2032	0.036	0.035	0.040	0.039	48.6	36.4	0.292	0.104	0.075	0.118	0.074	114												
2033	0.037	0.036	0.041	0.040	49.8	37.3	0.300	0.106	0.076	0.119	0.075	114												
2034	0.038	0.037	0.042	0.041	51.0	38.3	0.307	0.107	0.077	0.121	0.076	114												
2035	0.039	0.038	0.043	0.042	52.3	39.2	0.315	0.109	0.078	0.123	0.077	114												
2036	0.039	0.039	0.044	0.043	53.6	40.2	0.323	0.110	0.079	0.125	0.078	114												
2037	0.040	0.040	0.045	0.044	54.9	41.2	0.331	0.112	0.080	0.127	0.080	114												
2038	0.041	0.041	0.046	0.045	56.3	42.2	0.339	0.113	0.082	0.128	0.081	114												
2039	0.043	0.042	0.047	0.046	57.7	43.3	0.348	0.115	0.083	0.130	0.082	114												
2040	0.044	0.043	0.049	0.047	59.2	44.4	0.356	0.117	0.084	0.132	0.083	114												
Levelized																								
(2008-2040)	0.034	0.033	0.038	0.037	34.7	26.0	0.213																	
(2009-2040)	0.034	0.033	0.038	0.037	36.2	27.2	0.217																	
5 years (2008-12)	0.037	0.037	0.042	0.040	19.5	14.6	0.016																	
10 years (2008-17)	0.035	0.035	0.039	0.038	25.0	18.7	0.099																	
15 years (2008-22)	0.034	0.033	0.038	0.036	27.8	20.9	0.136																	
PV to 2008																								
PV to 2009																								

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

2) Projected environmental costs represent costs that are not yet internalized. Sustainability Target = Allowance Price (internalized value) + Environmental Cost

-A Costs are in NominalS; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours.
-S cludes June through September; Winter is all other months.
Syn nergy Economics – AESC 2007

3/31/07

Appendix F - New England Average Price Forecast of Other Fuel Prices by Sector (New as of 8/31/07)

New England Average Price Forecast of Other Fuel Prices by Sector (2007$)

Fuel	No. 2 Distillate	No. 2 Distillate	No. 6 Residual Fuel <= 1% Sulfur	No. 4 Fuel Oil	Propane	Kerosene	BioFuel	BioFuel	Wood
Market	Retail	Retail	Retail	Retail	Retail	Retail			Retail
Sector	Residential	Commercial	Commercial	Commercial	Residential	Res & Com	B5 Blend	B20 Blend	Residential
Notes	1	1	2	3	4	5	6	6	7
Year	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2007	15.84	13.97	9.46	11.71	26.81	16.47	15.84	15.84	5.67
2008	16.43	14.49	9.82	12.15	28.76	17.09	16.43	16.43	5.88
2009	16.05	14.15	9.59	11.87	28.97	16.69	16.05	16.05	5.75
2010	15.58	13.74	9.31	11.52	29.43	16.20	15.58	15.58	5.58
2011	15.10	13.32	9.03	11.17	29.71	15.71	15.10	15.10	5.41
2012	14.67	12.94	8.77	10.85	30.08	15.26	14.67	14.67	5.26
2013	14.22	12.54	8.50	10.52	29.61	14.79	14.22	14.22	5.09
2014	14.03	12.37	8.38	10.38	29.63	14.60	14.03	14.03	5.03
2015	14.10	12.43	8.42	10.43	29.55	14.66	14.10	14.10	5.05
2016	14.16	12.49	8.46	10.47	29.60	14.73	14.16	14.16	5.07
2017	14.29	12.60	8.54	10.57	29.85	14.86	14.29	14.29	5.12
2018	14.42	12.72	8.62	10.67	29.76	15.00	14.42	14.42	5.17
2019	14.55	12.83	8.69	10.76	29.69	15.13	14.55	14.55	5.21
2020	14.68	12.95	8.77	10.86	29.80	15.27	14.68	14.68	5.26
2021	14.88	13.12	8.89	11.00	29.67	15.47	14.88	14.88	5.33
2022	15.07	13.29	9.01	11.15	29.82	15.68	15.07	15.07	5.40
2023	15.27	13.47	9.12	11.30	29.97	15.88	15.27	15.27	5.47
2024	15.46	13.64	9.24	11.44	30.01	16.09	15.46	15.46	5.54
2025	15.66	13.81	9.36	11.58	30.02	16.29	15.66	15.66	5.61
2026	15.79	13.92	9.44	11.68	30.05	16.42	15.79	15.79	5.66
2027	15.92	14.04	9.51	11.78	30.15	16.56	15.92	15.92	5.70
2028	16.05	14.16	9.59	11.87	30.31	16.70	16.05	16.05	5.75
2029	16.18	14.27	9.67	11.97	30.41	16.83	16.18	16.18	5.80
2030	16.31	14.39	9.75	12.07	30.45	16.97	16.31	16.31	5.84
2031	16.48	14.53	9.85	12.19	30.75	17.14	16.48	16.48	5.90
2032	16.64	14.68	9.94	12.31	31.06	17.31	16.64	16.64	5.96
2033	16.81	14.82	10.04	12.43	31.37	17.48	16.81	16.81	6.02
2034	16.98	14.97	10.14	12.56	31.68	17.66	16.98	16.98	6.08
2035	17.15	15.12	10.25	12.68	32.00	17.83	17.15	17.15	6.14
2036	17.32	15.27	10.35	12.81	32.32	18.01	17.32	17.32	6.20
2037	17.49	15.42	10.45	12.94	32.64	18.19	17.49	17.49	6.26
2038	17.67	15.58	10.56	13.07	32.97	18.38	17.67	17.67	6.33
2039	17.84	15.73	10.66	13.20	33.30	18.56	17.84	17.84	6.39
2040	18.02	15.89	10.77	13.33	33.63	18.74	18.02	18.02	6.45
Levelized									
(2008-2040)	15.61	13.77	9.33	11.55	30.29	16.24	15.61	15.61	5.59
(2009-2040)	15.58	13.74	9.31	11.52	30.36	16.20	15.58	15.58	5.58
5 years (2008-12)	15.59	13.74	9.31	11.53	29.37	16.21	15.59	15.59	5.58
10 years (2008-17)	14.91	13.15	8.91	11.03	29.50	15.51	14.91	14.91	5.34
15 years (2008-22)	14.85	13.10	8.87	10.99	29.58	15.45	14.85	14.85	5.32

Notes

1 Based on adjusted AEO 2007 forecast for New England.
2 Adjusted AEO Electrical sector forecast
3 Based on historic price difference relative to Distillate.
4 Based on adjusted AEO 2007 forecast for New England.
5 Based on historic price difference relative to Distillate.
6 No premium or discount assigned for biofuels.
7 Based on historic relationship with distillate prices.
Levelized with a real discount rate of: 2.22%

New England Average Price Forecast of Other Fuel Prices by Sector (Nominal$)

Fuel	No. 2 Distillate	No. 2 Distillate	No. 6 Residual Fuel <= 1% Sulfur	No. 4 Fuel Oil	Propane	Kerosene	BioFuel	BioFuel	Wood
Market	Retail	Retail	Retail	Retail	Retail	Retail			Retail
Sector	Residential	Commercial	Commercial	Commercial	Residential	Res & Com	B5 Blend	B20 Blend	Residential
Notes	1	1	2	3	4	5	6	6	7
Year	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2007	15.84	13.97	9.46	11.71	26.81	16.47	15.84	15.84	5.67
2008	16.84	14.85	10.06	12.46	29.47	17.52	16.84	16.84	6.03
2009	16.86	14.87	10.07	12.47	30.43	17.54	16.86	16.86	6.04
2010	16.77	14.79	10.02	12.41	31.69	17.45	16.77	16.77	6.01
2011	16.67	14.70	9.96	12.33	32.79	17.34	16.67	16.67	5.97
2012	16.60	14.64	9.92	12.28	34.03	17.27	16.60	16.60	5.95
2013	16.49	14.54	9.86	12.20	34.33	17.16	16.49	16.49	5.91
2014	16.68	14.71	9.97	12.34	35.22	17.35	16.68	16.68	5.97
2015	17.17	15.14	10.26	12.70	36.00	17.86	17.17	17.17	6.15
2016	17.68	15.59	10.57	13.08	36.97	18.39	17.68	17.68	6.33
2017	18.29	16.13	10.93	13.53	38.21	19.03	18.29	18.29	6.55
2018	18.92	16.69	11.31	14.00	39.05	19.68	18.92	18.92	6.78
2019	19.57	17.26	11.69	14.47	39.93	20.35	19.57	19.57	7.01
2020	20.24	17.85	12.09	14.97	41.08	21.05	20.24	20.24	7.25
2021	21.02	18.54	12.56	15.55	41.93	21.86	21.02	21.02	7.53
2022	21.83	19.25	13.04	16.15	43.19	22.71	21.83	21.83	7.82
2023	22.67	19.99	13.55	16.77	44.48	23.58	22.67	22.67	8.12
2024	23.53	20.75	14.06	17.40	45.66	24.48	23.53	23.53	8.43
2025	24.43	21.54	14.60	18.07	46.81	25.41	24.43	24.43	8.75
2026	25.24	22.26	15.08	18.67	48.04	26.26	25.24	25.24	9.04
2027	26.09	23.01	15.59	19.30	49.41	27.14	26.09	26.09	9.35
2028	26.96	23.77	16.11	19.94	50.91	28.04	26.96	26.96	9.66
2029	27.86	24.56	16.65	20.61	52.35	28.98	27.86	27.86	9.98
2030	28.79	25.39	17.20	21.29	53.72	29.94	28.79	28.79	10.31
2031	29.80	26.28	17.81	22.04	55.62	31.00	29.80	29.80	10.67
2032	30.85	27.21	18.44	22.82	57.58	32.09	30.85	30.85	11.05
2033	31.94	28.17	19.09	23.63	59.61	33.22	31.94	31.94	11.44
2034	33.07	29.16	19.76	24.46	61.71	34.39	33.07	33.07	11.84
2035	34.23	30.19	20.45	25.32	63.88	35.61	34.23	34.23	12.26
2036	35.44	31.25	21.18	26.21	66.14	36.86	35.44	35.44	12.69
2037	36.69	32.35	21.92	27.14	68.47	38.16	36.69	36.69	13.14
2038	37.98	33.49	22.69	28.09	70.88	39.51	37.98	37.98	13.60
2039	39.32	34.67	23.50	29.08	73.38	40.90	39.32	39.32	14.08
2040	40.71	35.90	24.32	30.11	75.97	42.34	40.71	40.71	14.58
Levelized									
(2008-2040)	22.04	19.43	13.17	16.30	42.76	22.92	22.04	22.04	7.89
(2009-2040)	22.36	19.72	13.36	16.54	43.58	23.26	22.36	22.36	8.01
5 years (2008-12)	16.76	14.78	10.01	12.39	31.58	17.43	16.76	16.76	6.00
10 years (2008-17)	16.96	14.96	10.14	12.55	33.56	17.64	16.96	16.96	6.08
15 years (2008-22)	17.81	15.71	10.64	13.18	35.47	18.53	17.81	17.81	6.38

Notes

1 Based on adjusted AEO 2007 forecast for New England.
2 Adjusted AEO Electrical sector forecast
3 Based on historic price difference relative to Distillate.
4 Based on adjusted AEO 2007 forecast for New England.
5 Based on historic price difference relative to Distillate.
6 No premium or discount assigned for biofuels.
7 Based on historic relationship with distillate prices.
Levelized with a nominal discount rate of: 4.78%

THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 11-250

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Investigation of Merrimack Station Scrubber Costs and Cost Recovery

PREFILED TESTIMONY OF MICHAEL E. HACHEY
ON BEHALF OF TRANSCANADA POWER MARKETING LTD. AND
TRANSCANADA HYDRO NORTHEAST INC.

ATTACHMENT 18

EIA Analysis - link: http://www.eia.gov/oiaf/aeo/pdf/0383(2008).pdf

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June 2008

Annual Energy Outlook 2008

With Projections to 2030

For Further Information . . .

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The *Annual Energy Outlook 2008* will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early summer 2008. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available in early summer 2008, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System are available at web site http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation and will be updated for the *Annual Energy Outlook 2008* during 2008.

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With Projections to 2030

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Preface

The *Annual Energy Outlook 2008* (*AEO2008*), prepared by the Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2030. The projections are based on results from EIA's National Energy Modeling System (NEMS). EIA published an "early release" version of the *AEO2008* reference case in December 2007; however, the Energy Independence and Security Act of 2007 (EISA2007), which was enacted later that month, will have a major impact on energy markets, and given the year-long life of *AEO2008* and its use as a baseline for analyses of proposed policy changes, EIA decided to update the reference case to reflect the provisions of EISA2007.

The report begins with an "Overview" summarizing the *AEO2008* reference case and comparing it with the *Annual Energy Outlook 2007* (*AEO2007*) reference case. The Overview also includes a section that provides a comparison between the *AEO2008* released in December and the current version. The next section, "Legislation and Regulations," discusses evolving legislation and regulatory issues, including a summary of recently enacted legislation, such as EISA2007, and provides an update on the handling of aspects of previously enacted legislation, such as the loan guarantee program set up by Title XVII of the Energy Policy Act of 2005 (EPACT2005). This section also provides a summary of State renewable fuel requirements and emissions regulations and a discussion of how selected Federal fuel taxes and tax credits are handled in *AEO2008*.

The "Issues in Focus" section includes discussion of a scenario under which electricity generation options other than natural gas are restricted and natural gas supply is limited; the competitive factors that influence imports of liquefied natural gas (LNG); and the implications of changing the basis for measuring heating and cooling degree-days. It also discusses the implications of uncertainty in energy project costs and the basis of the world oil price and production trends in *AEO2008*.

The "Market Trends" section summarizes the projections for energy markets. The analysis in *AEO2008* focuses primarily on a reference case, low and high economic growth cases, and low and high energy price cases. Results from a number of other alternative cases are also presented, illustrating uncertainties associated with the reference case projections for energy demand, supply, and prices. Complete tables for the five primary cases are provided in Appendixes A through C. Major results from many of the alternative cases are provided in Appendix D.

AEO2008 projections are based on Federal, State, and local laws and regulations in effect on or before December 31, 2007. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections.

In general, historical data used in the *AEO2008* projections are based on EIA's *Annual Energy Review 2006*, published in June 2007. Other historical data, taken from multiple sources, are presented for comparative purposes; documents referenced in the source notes should be consulted for official data values.

AEO2008 is published in accordance with Section 205c of the Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

Projections in *AEO2008* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend estimates, given known technology and technological and demographic trends. *AEO2008* assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral reference case that can be used to analyze policy initiatives.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2008* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

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Overview

Overview

Energy Trends to 2030

In preparing projections for *AEO2008*, EIA evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between today and 2030. This overview focuses on one case, the reference case, which is presented and compared with the *AEO2007* reference case (see Table 1). Readers are encouraged to review the full range of alternative cases included in other sections of *AEO2008*.

As in previous editions of the *Annual Energy Outlook* (*AEO*), the reference case assumes that current policies affecting the energy sector remain unchanged throughout the projection period. The reference case provides a clear basis against which alternative cases and policies can be compared. Although current laws and regulations may change over the next 25 years, and new ones may be created, it is not possible to predict what they will be or how they will be implemented [*1*].

EIA published an "early release" version of the *AEO2008* reference case in December 2007. Later that month, EISA2007 was enacted. The provisions in EISA2007 will have a major impact on energy markets, particularly liquid fuels. Given the year-long life of *AEO2008* and its use as a baseline for analyses of proposed policy changes, EIA decided to update the reference case to reflect the provisions of EISA2007. A short summary of the impact of including EISA-2007 is provided in the box on pages 3 and 4.

Trends in energy supply and demand are affected by many factors that are difficult to predict, including energy prices, U.S. and worldwide economic growth, advances in technologies, and future public policy decisions both in the United States and in other countries. As noted in *AEO2007*, energy markets are changing in response to readily observable factors, which include, among others: higher energy prices; the growing influence of developing countries on worldwide energy requirements; recently enacted legislation and regulations in the United States; changing public perceptions on issues related to emissions of air pollutants and greenhouse gases (GHGs) and the use of alternative fuels and; and the economic viability of various energy technologies.

Projections in the *AEO2008* reference case have been updated to better reflect trends that are expected to persist in the economy and in energy markets. For example, the projection for U.S. economic growth, a key determinant of U.S. energy demand, is lower in *AEO2008* than it was in *AEO2007*, reflecting an updated assumption for productivity improvement. Other key changes in the *AEO2008* projections include:

- Higher price projections for crude oil and natural gas
- Higher projections for delivered energy prices, reflecting both higher wellhead and minemouth prices and higher costs to transport, distribute, and refine fuels per unit supplied
- Slower projected growth in energy demand (particularly for natural gas but also for liquid fuels and coal)
- Faster projected growth in the use of nonhydroelectric renewable energy, resulting from a revised representation of State renewable portfolio standard (RPS) provisions
- Higher projections for domestic oil production, particularly in the near term
- Slower projected growth in energy imports, both natural gas and oil
- Slower projected growth in energy-related emissions of carbon dioxide (CO_2).

Coal, liquid fuels (excluding the biofuels portion of total liquids supply), and natural gas meet 80 percent of total U.S. primary energy supply requirements in 2030—down from an 85-percent share in 2006, reflecting the incorporation of EISA2007 provisions, slower economic growth, higher energy prices, lower total energy demand, and increased use of renewable energy when compared with *AEO2007*.

Economic Growth

The *AEO2008* reference case reflects reduced expectations for economic growth: U.S. gross domestic product (GDP) grows at an average annual rate of 2.4 percent from 2006 to 2030—0.4 percentage points slower than the rate in the *AEO2007* reference case over the same period. The main factor contributing to the slower rate of growth in GDP is a lower estimate of growth in labor productivity. Nonfarm business labor productivity grows by 1.9 percent per year in the *AEO2008* reference case, compared with 2.3 percent per year in *AEO2007*. Nonfarm employment growth is 0.9 percent per year in the *AEO2008* reference case, about the same as in *AEO2007*. From 2006 to 2030, total industrial shipments grow by

Impacts of Updating the AEO2008 Reference Case

EIA's decision to update the *AEO2008* early-release reference case was motivated by the enactment in December 2007 of EISA2007, which contains many provisions that will significantly influence future energy trends. The specific EISA2007 provisions modeled in *AEO2008* include updates to the renewable fuel standard (RFS) and the corporate average fuel economy (CAFE) standard for new light-duty vehicles (LDVs); updated and new appliance energy efficiency standards for boilers, dehumidifiers, dishwashers, clothes washers, and commercial walk-in refrigerators and freezers; lighting energy efficiency standards; provisions to reduce energy consumption in Federal buildings; and efficiency standards for industrial electric motors.

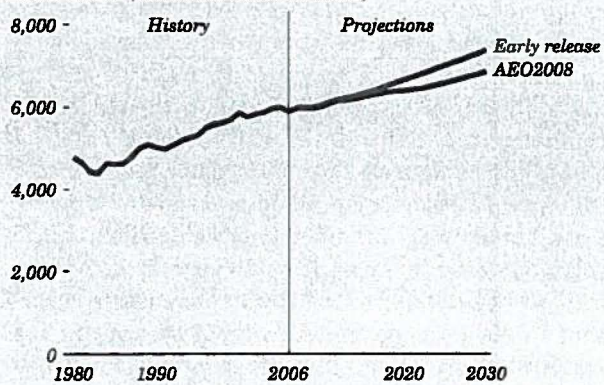
Consistent with the general approach used in past *AEO*s, the reference case does not consider those sections of EISA2007 that require appropriations for implementation or sections with highly uncertain impacts on energy markets. It also includes additional revisions that reflect historical data issued after the *AEO2008* early-release reference case was completed, new data from EIA's January 2008 *Short-Term Energy Outlook* (*STEO*), a more current economic outlook, and technical updates to the earlier version of NEMS.

Total energy consumption and greenhouse gas emissions

EISA2007 has a significant impact on both projected total energy consumption and GHG emissions. Total primary energy consumption in the *AEO2008* reference case grows by 18.5 quadrillion British thermal units (Btu), from 99.5 quadrillion Btu in 2006 to 118.0 quadrillion Btu in 2030—5.3 quadrillion Btu less than in the early-release reference case. Although other changes were also made, the inclusion of EISA2007 is by far the most important. In 2030, the projected consumption levels for liquid fuels, natural gas, and coal all are lower in the *AEO2008* reference case than they were in the early-release case.

Without the application of carbon capture and sequestration (CCS) technology, CO_2 emissions from the combustion of fossil fuels are proportional to the consumption and carbon content of the fuels. Inclusion of EISA2007 provisions in the *AEO2008* reference case both reduces total energy consumption and shifts consumption to fuels that are less carbon-intensive or are carbon-neutral. As a result, the projection for total energy-related CO_2 emissions in 2030 is 6,851 million metric tons in the *AEO2008* reference case, as compared with 7,373 million metric tons in the early-release reference case—a difference of 7 percent or 522 million metric tons (see figure below). The difference between the two cases grows over time, so that cumulative energy-related CO_2 emissions over the period from 2008 to 2030 are 5.3 billion metric tons lower in the *AEO2008* reference case than in the early-release reference case.

Total annual carbon dioxide emissions in the early-release and AEO2008 reference cases, 1980-2030 (million metric tons)



Liquid fuels consumption and imports

The combination of a higher CAFE standard for new LDVs and an updated RFS has a substantial impact on the level and mix of liquids consumption. Total liquids consumption[a] in 2030 in the *AEO2008* reference case, including the impact of EISA2007, is 22.8 million barrels per day—2.1 million barrels per day lower than in the early-release reference case.

Conventional petroleum consumption in 2030, excluding biofuels but including coal-to-liquids (CTL) diesel (a nonrenewable fuel), is 2.9 million barrels per day less in the *AEO2008* reference case. On an energy basis, total liquids consumption is 44.0 quadrillion Btu in 2030 in the *AEO2008* reference case, about 9 percent lower than projected in the early-release case.

(continued on page 4)

[a]Liquid fuels include conventional petroleum products, ethanol, biodiesel, diesel from biomass, CTL, and gas-to-liquids.

1.3 percent per year in the *AEO2008* reference case, as compared with 2.0 percent per year in *AEO2007*.

Energy Prices

EIA raised the reference case path for world oil prices in *AEO2008* (although the upward adjustment is smaller than the last major adjustment, introduced in *AEO2006*). The real world crude oil price (which for the purposes of *AEO2008* is defined as the price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, in 2006 dollars) declines gradually from current levels to $57 per barrel in 2016 ($68 per barrel in nominal dollars), as expanded investment in exploration and development brings new supplies to world markets. After 2016, real prices begin to rise (Figure 1), as demand continues to grow and higher cost supplies are brought to market. In 2030, the average real price of crude oil is $70 per barrel in 2006 dollars, or about $113 per barrel in nominal dollars. Alternative *AEO2008* cases address higher and lower world crude oil prices.

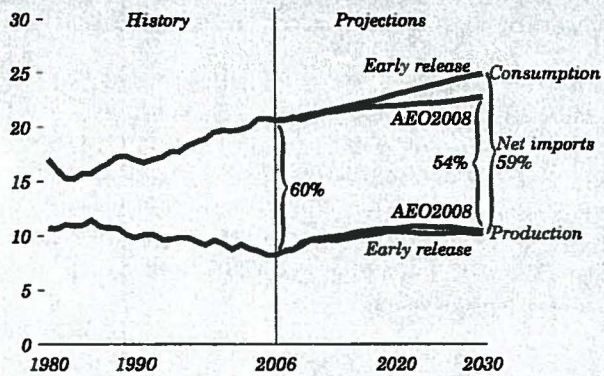
In developing its oil price outlook, EIA explicitly considered four factors: (1) growth in world liquids consumption; (2) the outlook for conventional oil production in countries outside the Organization of the Petroleum Exporting Countries (OPEC); (3) growth

Impacts of Updating the AEO2008 Reference Case (continued)

In the *AEO2008* reference case, because a large share of the biofuels consumed is produced domestically, net imports of liquid fuels (including both crude oil and products) are reduced by more relative to the early-release case than is total liquids consumption. Total net imports of liquids in 2030 are 2.4 million barrels per day lower in the *AEO2008* reference case than in the early-release case. As shown in the figure below, U.S. dependence on net imports of liquid fuels (including crude oil and refined liquids) on a volumetric basis declines in the *AEO2008* reference case from 60 percent in 2006 to 51 percent in 2022, followed by an increase to 54 percent in 2030—as compared with 59 percent in the early-release reference case. Even with the increase in biofuel use and the higher vehicle efficiency standards, however, petroleum products still account for 88 percent of total transportation energy consumption in the *AEO2008* reference case, compared with 96 percent in 2006.

The fuel mix for vehicles also changes between the two cases. The figure below shows the mix of fuels for LDVs in 2030 on an energy basis in the two cases. Biofuel consumption, excluding CTL, reaches 2.0 quadrillion Btu (23.5 billion gallons) in 2030, or about 11 percent of total demand for motor vehicle fuel in the *AEO2008* reference case—an increase of 0.6 quadrillion Btu (7.1 billion gallons) from the early-release reference case and 1.6 quadrillion Btu (18.2 billion gallons) more than in 2006. The increase in the *AEO2008* reference case includes more ethanol consumption—both ethanol blended with gasoline in E10 (gasoline containing up to 10 percent ethanol by volume) and as E85 (fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume)—and more biodiesel consumption than in the early-release projection.

U.S. liquids supply, consumption, and net imports in the early-release and AEO2008 reference cases, 1980-2030 (million barrels per day)



Light-duty vehicle energy use by fuel in the early-release and AEO2008 reference cases, 2030 (quadrillion Btu)

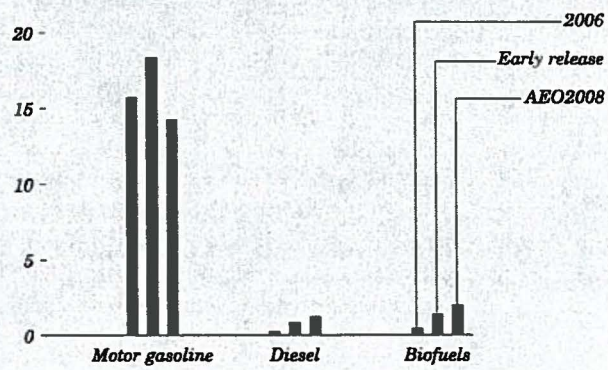
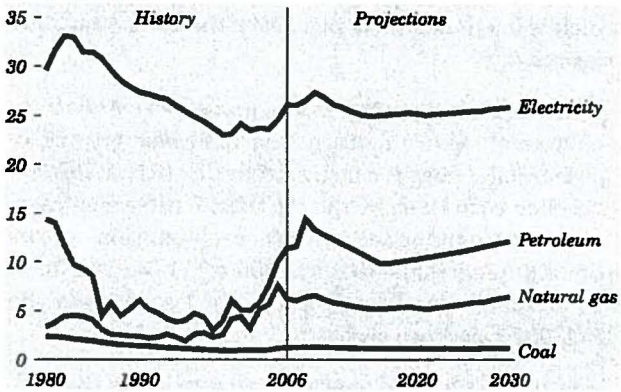


Figure 1. Energy prices, 1980-2030 (2006 dollars per million Btu)



in unconventional liquids production; and (4) OPEC behavior. With the forces driving demand outside the United States as strong as, or stronger than, previously expected but with global supply projections somewhat weaker, oil prices in *AEO2008* are higher than projected in *AEO2007* [2].

As a result of recent strong economic growth worldwide, transitory shortages of experienced personnel, equipment, and construction materials in the oil industry, and political instability in some major producing regions, oil prices currently are above EIA's estimate of the long-run equilibrium price. EIA's expectations regarding the ultimate size of both conventional and unconventional liquid resources have not changed since last year's *AEO*.

The *AEO2008* reference case represents EIA's current judgment about the most likely behavior of key OPEC members in the mid-term. In the projection, OPEC countries increase production at a rate that keeps their market share of world liquids production at approximately 40 percent through 2030.

The *AEO2008* reference case also projects significant long-term potential for supply from non-OPEC producers. In several resource-rich regions—including Brazil, Azerbaijan, and Kazakhstan—high oil prices, expanded infrastructure, and new exploration and drilling technologies permit additional non-OPEC oil production. Also, with the economic viability of Canada's oil sands enhanced by higher world oil prices and advances in production technology, oil sands production is expected to reach 4 million barrels per day in 2030.

The price of natural gas also is higher in the *AEO2008* reference case. The real wellhead price of natural gas (in 2006 dollars) declines from current levels through 2016, as new supplies enter the market. After some fluctuations through 2021, real natural gas prices rise to $6.63 per thousand cubic feet in 2030 ($10.64 per thousand cubic feet in nominal dollars). The higher prices in the *AEO2008* reference case reflect an increase in production costs associated with recent trends that were discussed in *AEO2007* but were not reflected fully in the *AEO2007* reference case [3]. The higher natural gas prices also are supported by higher oil prices.

Minemouth coal prices in the *AEO2008* reference case, both nationally and regionally, are generally similar to those projected in the *AEO2007* reference case. By region, the largest price difference is for Wyoming's Powder River Basin, where the projected average minemouth price in 2030 is 12.1 percent above the *AEO2007* projection, at $0.66 (2006 dollars) per million Btu, reflecting a less optimistic outlook for improvements in coal mining productivity.

Average real minemouth coal prices (in 2006 dollars) fall from $1.21 per million Btu ($24.63 per short ton) in 2006 to $1.14 per million Btu ($22.45 per short ton) in 2018 in the *AEO2008* reference case, as prices moderate following a substantial run-up over the past few years. After 2020, coal prices rise as demand increases, reaching $1.19 per million Btu ($23.32 per short ton) in 2030. The 2020 and 2030 price projections are 2.6 percent and 0.9 percent higher, respectively, than those in the *AEO2007* reference case. Without adjustment for inflation, the average minemouth price of coal in the *AEO2008* reference case is $1.91 per million Btu ($37.42 per ton) in 2030.

AEO2008 projects higher prices for most energy fuels delivered to consumers. For example, in 2030, the average delivered price of natural gas (in 2006 dollars) is more than $1 per million Btu higher in the *AEO2008* reference case than was projected in *AEO2007*. In part, the higher delivered prices result from higher prices paid to fossil fuel producers at the wellhead or minemouth; but they also result from updates made to assumptions about the costs to transport, distribute, and refine the fuels to make them more consistent with recent trends. For example, as a result of declining use per customer and the growing cost of bringing supplies from new regions to market, margins between the delivered and wellhead prices of natural gas are higher than previously projected. Factors contributing to higher margins for liquid fuels include continued growth in the use of heavier and sourer crudes, growing demand for cleaner products,

and the rising cost of refinery safety and emissions abatement.

Increases in diesel fuel prices in recent years have led railroads to implement fuel adjustment surcharges on coal shipments, which are incorporated in the *AEO2008* reference case. The average real delivered price of coal to power plants (in 2006 dollars) increases from $1.69 per million Btu ($33.85 per short ton) in 2006 to $1.78 per million Btu ($35.03 per short ton) in 2030, 2.3 percent higher than in the *AEO2007* reference case. In nominal dollars, the average delivered price of coal to power plants is projected to reach $2.86 per million Btu ($56.22 per short ton) in 2030.

Electricity prices follow trends in the delivered prices of fuels to power plants in the reference case. From a peak of 9.3 cents per kilowatthour (2006 dollars) in 2009, average delivered electricity prices decline to 8.5 cents per kilowatthour in 2015 and then increase to 8.8 cents per kilowatthour in 2030. In the *AEO2007* reference case, with slightly lower expectations for delivered fuel prices and construction costs for all new technologies, electricity prices reached 8.3 cents per kilowatthour (2006 dollars) in 2030. In nominal dollars, the average delivered electricity price in the *AEO2008* reference case reaches 14.1 cents per kilowatthour in 2030.

Energy Consumption by Sector

Total primary energy consumption in the *AEO2008* reference case grows by 19 percent between 2006 and 2030 (an average rate of 0.7 percent per year), from 99.5 quadrillion Btu in 2006 to 118.0 quadrillion Btu in 2030—13.2 quadrillion Btu less than in the *AEO2007* reference case. In 2030, the levels of consumption projected for liquid fuels, natural gas, and coal are lower in the *AEO2008* reference case than they were in the *AEO2007* reference case. Among the most important factors leading to lower total energy demand in the *AEO2008* reference case are lower economic growth, greater use of more efficient appliances and vehicles, higher energy prices, and slower growth in energy-intensive industries.

Residential delivered energy consumption in the *AEO2008* reference case grows from 10.8 quadrillion Btu in 2006 to 12.9 quadrillion Btu in 2030, or by 0.7 percent per year (Figure 2). Higher delivered energy prices, slower growth in the housing stock, increases in lighting efficiency to meet the standards established in EISA2007, and a revised accounting of heating and cooling degree-days to better reflect recent temperature trends contribute to the lower level of residential energy use in the *AEO2008* projection, which is 0.9 quadrillion Btu lower than the *AEO2007* projection.

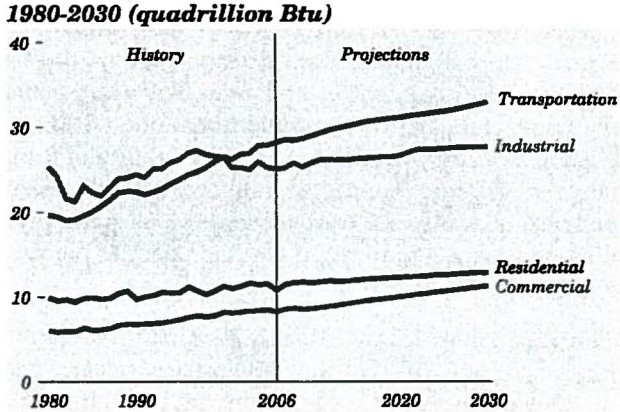
Higher delivered energy prices and slower growth in commercial square footage lead to slower growth in commercial energy consumption in the *AEO2008* reference case than in the *AEO2007* reference case. Delivered commercial energy consumption grows from 8.3 quadrillion Btu in 2006 to 11.3 quadrillion Btu in 2030, over 1 quadrillion Btu less than in the *AEO2007* reference case.

Since 1997, delivered energy consumption in the U.S. industrial sector has trended downward, falling from about 27 quadrillion Btu in 1997 to 25 quadrillion Btu in 2006, despite rising output. A number of factors have worked to reduce industrial energy consumption since 1997: economic weakness between 2000 and 2003, the hurricanes of 2005 that reduced activity in some industrial subsectors, and rising energy prices.

Industrial delivered energy consumption increases to 27.7 quadrillion Btu in 2030. Although the *AEO2008* reference case includes steady economic growth and declining energy prices in the near term, growth in the energy-intensive industries continues to be weak, reflecting increased competition from foreign regions with lower relative energy prices. Growth in the energy-intensive U.S. manufacturing industries averages 0.7 percent per year from 2006 to 2030, slower than the 1.3-percent average growth in *AEO2007*.

Delivered energy consumption in the transportation sector grows to 33.0 quadrillion Btu in 2030 in the *AEO2008* reference case, 6.3 quadrillion Btu less than in *AEO2007*. The lower projected level of consumption predominantly reflects the influence of the new

Figure 2. Delivered energy consumption by sector, 1980-2030 (quadrillion Btu)



CAFE standard for LDVs specified in EISA2007 and slower economic growth, as well as the impact of higher fuel prices.

EISA2007 requires new LDVs, including both cars and trucks, to reach a combined average fuel economy of 35 miles per gallon (mpg) by 2020, based on the U.S. Environmental Protection Agency (EPA) test value used to measure compliance with the CAFE standard. The EPA CAFE test value generally differs from the estimated mpg value on the fuel economy label and, typically, exceeds the actual on-the-road fuel economy of a new vehicle by a significant margin. Despite these differences, the higher fuel economy standards in EISA2007 significantly improve the in-use fuel economy of the LDV stock. In the reference case, the average in-use fuel economy for the stock of LDVs in 2030 increases to 27.9 mpg, almost 40 percent above its 2006 level. To attain these fuel economy levels, the projection reflects increases in the sale of unconventional vehicle technologies [*4*], such as flex-fuel, hybrid, and diesel vehicles, and a slowdown in the growth of new light truck sales.

Energy Consumption by Primary Fuel

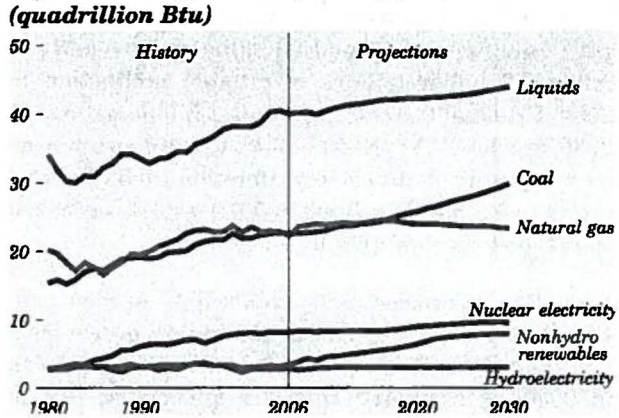
Total consumption of liquid fuels, including both fossil liquids and biofuels, grows from 20.7 million barrels per day in 2006 to 22.8 million barrels per day in 2030 in the *AEO2008* reference case (Figure 3), less than the *AEO2007* reference case projection of 26.9 million barrels per day in 2030. Liquid fuels consumption is lower in all sectors in *AEO2008* than in the *AEO2007* reference case, as a result of incorporation of the new LDV CAFE standard specified in EISA-2007, slower economic growth, and higher delivered prices for liquid fuels. Much of the difference is in the transportation sector.

In *AEO2008*, natural gas consumption increases from 21.7 trillion cubic feet in 2006 to 23.8 trillion cubic feet in 2016, then declines to 22.7 trillion cubic in 2030 (Figure 3). The projection for natural gas consumption in the *AEO2008* reference case is sharply lower than in *AEO2007*, where consumption grew to 26.1 trillion cubic feet in 2030. Consumption is lower in all sectors in *AEO2008*, and particularly in the industrial and electricity power sectors. Industrial natural gas use is 1.7 trillion cubic feet lower in 2030 in the *AEO2008* reference case (8.1 trillion cubic feet, compared with 9.8 trillion cubic feet in *AEO2007*), as a result of higher delivered prices for natural gas, lower economic growth, and a reassessment of natural gas use in the energy-intensive industries. In *AEO2008*, electricity generation accounts for 5.0 trillion cubic feet of natural gas use in 2030, compared with the *AEO2007* projection of 5.9 trillion cubic feet. The lower level of consumption in *AEO2008* results from higher natural gas prices and slower growth in electricity demand.

Total coal consumption increases from 22.5 quadrillion Btu (1,114 million short tons) in 2006 to 29.9 quadrillion Btu (1,545 million short tons) in 2030 in the *AEO2008* reference case. As in the *AEO2007* reference case, coal consumption is projected to grow at a faster rate toward the end of the projection period, particularly after 2020, as coal use for new coal-fired generating capacity grows rapidly. In the *AEO2008* reference case, coal consumption in the electric power sector increases from 23.7 quadrillion Btu in 2020 to 27.5 quadrillion Btu in 2030, and coal use at CTL plants increases from 0.6 quadrillion Btu in 2020 to 1.0 quadrillion Btu in 2030. The projected increase in coal use for CTL plants is lower than in previous *AEO*s as a result of EISA2007, because investment dollars that previously would have gone into CTL capacity now flow to biomass-to-liquids (BTL) capacity; however, there is a great deal of uncertainty around this projection.

The *AEO2008* reference case projects substantially greater use of renewable energy than was projected in *AEO2007*. Total consumption of marketed renewable fuels—including ethanol for gasoline blending, biodiesel [*5*], and diesel from biomass [*6*], of which 2.8 quadrillion Btu in 2030 is included with liquids fuel consumption—grows by 3.0 percent per year in the reference case, from 6.8 quadrillion Btu in 2006 to 13.7 quadrillion Btu in 2030, compared with 9.9 quadrillion Btu in *AEO2007*. About 45 percent of the demand for renewables in 2030 is for grid-related

Figure 3. Energy consumption by fuel, 1980-2030 (quadrillion Btu)



electricity generation (including combined heat and power [CHP]).

The rapid growth in the use of renewable fuels for transportation in *AEO2008* reflects the EISA2007 RFS, which sets a requirement for 21 billion gallons of advanced biofuels and 36 billion gallons of total renewable fuels by 2022. Included are requirements for 1 billion gallons of biodiesel and 16 billion gallons of cellulosic biofuels, both of which count toward the advanced biofuels requirement. The remaining 4 billion gallons of advanced biofuels may come from any source. The difference between advanced biofuels and total renewable fuels may be met by corn ethanol. Diesel fuels derived from biomass feedstocks count for 1.5 times their physical volume in the calculation of credits toward the RFS requirements, because diesel has a higher energy content per gallon than ethanol does.

Although the situation is very uncertain, the current state of the industry and EIA's present view of projected rates of technology development and market penetration of cellulosic biofuel technologies suggest that available quantities of cellulosic biofuels before 2022 will be insufficient to meet the new RFS targets for cellulosic biofuels, triggering both waivers and a modification of applicable volumes, as provided for in Section 211(o) of the Clean Air Act as amended by EISA2007. The modification of volumes reduces the overall target in 2022 from 36 billion gallons to 32.5 billion gallons in the *AEO2008* reference case.

Ethanol use in the *AEO2008* reference case, grows from 5.6 billion gallons in 2006 to 23.9 billion gallons in 2030—about 16 percent of total gasoline consumption by volume and about 65 percent more than in *AEO2007*. Ethanol use for gasoline blending grows to 13.4 billion gallons and E85 consumption to 10.5 billion gallons in 2030. The ethanol supply is expected to be produced from both corn and cellulose feedstocks, with corn accounting for 15.0 billion gallons and cellulose 6.9 billion gallons of ethanol production in 2030. Biodiesel use increases to 1.2 billion gallons in 2030, or about 1.5 percent of total diesel consumption by volume. In addition, consumption of BTL diesel grows to 4.5 billion gallons in 2030, or 5.3 percent of total diesel consumption by volume.

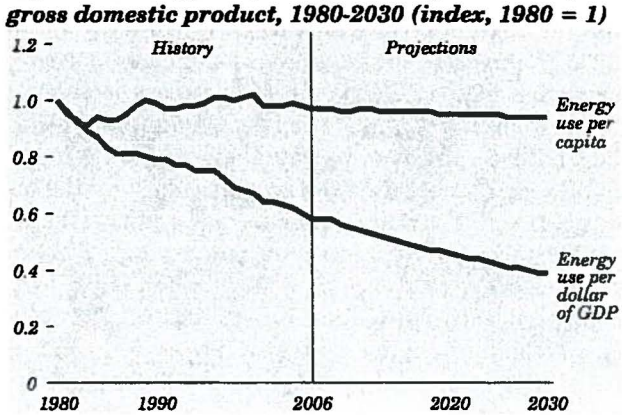
Excluding hydroelectricity, renewable energy consumption for electric power generation grows from 0.9 quadrillion Btu in 2006 to 3.2 quadrillion Btu in 2030, as compared with 2.1 quadrillion Btu in *AEO2007*. The higher level of nonhydroelectric renewable energy consumption in the *AEO2008* reference case reflects primarily a revised representation of State RPS programs, which require that specific and generally increasing shares of electricity sales be supplied by renewable resources, such as wind, solar, geothermal, and sometimes biomass or hydropower. Previous *AEO*s placed more weight on the "escape clauses" incorporated in many State RPS programs, given that the consumer costs of the programs would increase significantly if the Federal production tax credit (PTC) for qualifying renewable energy expired as provided for under current law. The new representation, which assumes that the State RPS goals will be met absent a clear contrary indication, results in significant additional growth of renewable generation from wind, biomass, and geothermal resources.

Energy Intensity

Energy intensity, measured as primary energy use (in thousand Btu) per dollar of GDP (in 2000 dollars), declines by about one-third from 2006 to 2030 in the *AEO2008* reference case (Figure 4). Although energy use generally increases as the economy grows, continuing improvement in the energy efficiency of the U.S. economy and a shift to less energy-intensive activities are projected to keep the rate of energy consumption growth lower than the rate of GDP growth.

Since 1992, the energy intensity of the U.S. economy has declined on average by 2.0 percent per year, in part because the share of industrial shipments accounted for by the energy-intensive industries has fallen from 30 percent in 1992 to 21 percent in 2006. In the *AEO2008* reference case, the energy-intensive industries' share of total industrial shipments continues to decline, although at a slower rate, to 18 percent in 2030.

Figure 4. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



Population is a key determinant of energy consumption, influencing demand for travel, housing, consumer goods, and services. Since 1990, the population has increased by about 20 percent and energy consumption by a comparable 18 percent in the United States, with annual variations in energy use per capita resulting from variations in weather and economic factors. The age, income, and geographic distribution of the population also affect the growth of energy consumption. Aging of the population, a gradual shift from the North to the South, and rising per-capita income will influence future trends. Overall, the U.S. population increases by 22 percent from 2006 to 2030 in the *AEO2008* reference case. Over the same period, energy consumption increases by 19 percent. The result is a decrease in energy consumption per capita at an annual rate of 0.1 percent per year from 2006 to 2030, a drop from the 0.3-percent yearly increase in the *AEO2007* reference case.

Recently, as energy prices have risen, the potential for more energy conservation has received increased attention. Although additional energy conservation is induced by higher energy prices in the *AEO2008* reference case and by the passage of EISA2007, no further policy-induced conservation measures are assumed beyond those in existing legislation and regulation, nor does the reference case assume behavioral changes beyond those observed in the past.

Energy Production and Imports

Net imports of energy are expected to continue meeting a major share of total U.S. energy demand (Figure 5). The increased use of biofuels resulting from EISA2007, much of which is domestically produced, and the reduction in demand for transportation fuels due to the new CAFE standards both serve to moderate growth in energy imports. Higher fuel prices over the projection period also spur increased domestic energy production (Figure 6) and moderate energy demand growth, further tempering growth in imports. The projected net import share of total U.S. energy consumption in 2030 is 27 percent, a decline from the 30-percent share in 2006.

The projection for U.S. crude oil production in the *AEO2008* reference case is higher than in the *AEO2007* reference case, primarily as a result of more production from the expansion of enhanced oil recovery (EOR) operations and, to a lesser extent, higher crude oil prices. U.S. crude oil production in the *AEO2008* reference case increases from 5.1 million barrels per day in 2006 to a peak of 6.3 million barrels per day in 2018, with production increases from the deep waters of the Gulf of Mexico and from onshore EOR projects. Domestic production subsequently declines to 5.6 million barrels per day in 2030, as increased production from new, smaller discoveries is inadequate to offset declines in production from large fields in Alaska and the Gulf of Mexico.

Total domestic liquids supply, including crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs (including ethanol, biodiesel, BTL, and liquids from coal) generally increase through 2022 in the *AEO2008* reference case, while imports of crude oil and other petroleum products remain flat. Total domestic liquids supply grows from 8.2 million barrels per day in 2006 to 10.4 million barrels per day in 2030.

In the *AEO2008* reference case, the net import share of total liquids supplied, including crude oil and refined products, drops from 60 percent in 2006 to 51 percent in 2022 and then increases to 54 percent in

Figure 5. Total energy production and consumption, 1980-2030 (quadrillion Btu)

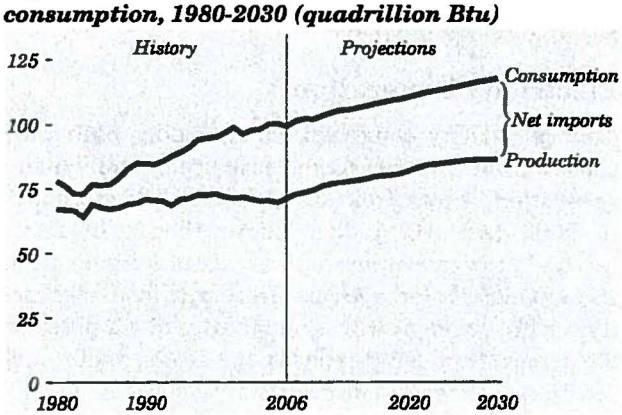
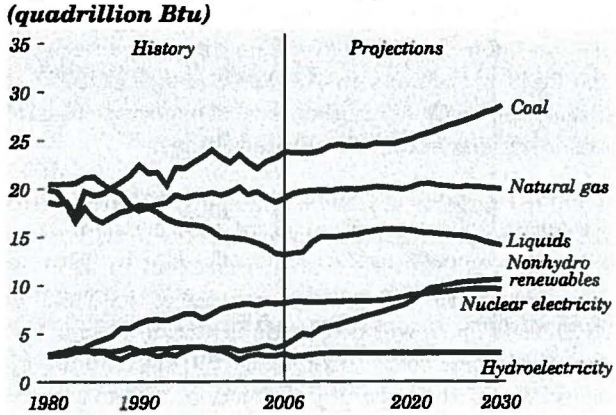


Figure 6. Energy production by fuel, 1980-2030 (quadrillion Btu)



2030. Net imports of crude oil and net imports of petroleum products in 2030 each are about 2.0 million barrels per day lower in the *AEO2008* reference case than in the *AEO2007* reference case. The primary reasons for the difference between the *AEO2008* and *AEO2007* projections for net imports of liquid fuels are a lower level of total liquids consumption and a higher level of biofuels consumption in the transportation sector in the *AEO2008* reference case.

Total domestic production of natural gas (including supplemental natural gas supplies) increases from 18.6 trillion cubic feet in 2006 to 20.0 trillion cubic feet in 2022 before declining to 19.5 trillion cubic feet in 2030 in the *AEO2008* reference case. The projections are lower than in the *AEO2007* reference case, which showed production increasing to 20.6 trillion cubic feet in 2030, primarily because of higher costs associated with exploration and development and, particularly in the last decade of the projection, lower demand for natural gas in *AEO2008*. Onshore production of unconventional natural gas is expected to be a key contributor to the growth in U.S. supply, increasing from 8.5 trillion cubic feet in 2006 to a peak of 9.6 trillion cubic feet in 2018 and generally holding at about that level through 2030.

The Alaska natural gas pipeline is expected to be completed in 2020 (2 years later than in the *AEO2007* reference case, because of delays in the resolution of issues between Alaska's State government and industry participants). After the pipeline goes into operation, Alaska's total natural gas production in the *AEO2008* reference case increases to 2.0 trillion cubic feet in 2021 (from 0.4 trillion cubic feet in 2006) and then remains at that level through 2030.

Net pipeline imports of natural gas from Canada and Mexico fall from 2.9 trillion cubic feet in 2006 to 0.3 trillion cubic feet in 2030 in the *AEO2008* reference case (compared with the *AEO2007* projection of 0.9 trillion cubic feet in 2030). The difference between the 2030 projections in *AEO2008* and *AEO2007* is largely the result of a higher level of exports to Mexico and lower demand in the United States.

Total net imports of LNG to the United States in the *AEO2008* reference case increase from 0.5 trillion cubic feet in 2006 to 2.8 trillion cubic feet in 2030, as compared with 4.5 trillion cubic feet in 2030 in *AEO2007*. The lower projection is attributable to two factors: higher costs throughout the LNG industry, especially in the area of liquefaction, and decreased U.S. natural gas consumption due to higher natural gas prices, slower economic growth, and expected greater competition for supplies in the global LNG market.

The future direction of the global LNG market is one of the key uncertainties in the *AEO2008* reference case. With many new international players entering LNG markets, the competition for available supplies is strong, and the amounts available to the U.S. market may vary considerably from year to year. The *AEO2008* reference case has been updated to reflect current market dynamics, which could change considerably as worldwide LNG markets evolve.

As domestic coal demand grows in the *AEO2008* reference case, U.S. coal production (excluding waste coal) increases at an average rate of 0.8 percent per year, from 23.8 quadrillion Btu (1,163 million short tons) in 2006 to 28.6 quadrillion Btu (1,455 million short tons) in 2030—15 percent less than in the *AEO2007* reference case. Production from mines west of the Mississippi River provides the largest share of the incremental coal production. On a Btu basis, 59 percent of domestic coal production originates from States west of the Mississippi River in 2030, up from 49 percent in 2006.

Typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 91 percent of total coal consumption. Coal consumption in the electric power sector in the *AEO2008* reference case, at 27.5 quadrillion Btu in 2030, is less than in the *AEO2007* reference case (31.1 quadrillion Btu in 2030). Slower growth in overall electricity demand, combined with more generation from nuclear and renewable energy, underlies the reduced outlook for electricity sector coal consumption. Another emerging market for coal is CTL. Coal use in CTL plants grows from 0.6 quadrillion Btu (42 million short tons) in 2020 to 1.0 quadrillion Btu (64 million short tons) in 2030.

Electricity Generation

Total electricity consumption, including both purchases from electric power producers and on-site generation, grows from 3,814 billion kilowatthours in 2006 to 4,972 billion kilowatthours in 2030, increasing at an average annual rate of 1.1 percent in the *AEO2008* reference case. In comparison, electricity consumption grew by annual rates of 4.2 percent, 2.6 percent, and 2.3 percent in the 1970s, 1980s, and 1990s, respectively. The growth rate in the *AEO2008*

projection is lower than in the *AEO2007* reference case (1.5 percent per year). The reduced rate of growth in *AEO2008* results from slower economic growth, the imposition of new efficiency standards in EISA2007, and higher electricity prices.

In the *AEO2008* reference case, electricity generation from natural-gas-fired power plants increases sharply from 2006 to 2008 and then remains relatively stable for the next decade, growing by 3 percent from 2008 to 2016—less rapidly than in the *AEO2007* reference case. After 2016, however, generation from new coal, nuclear, and renewable plants displaces some natural-gas-fired generation (Figure 7). In the *AEO2008* reference case, 741 billion kilowatthours of electricity is generated from natural gas in 2030, 21 percent less than the 937 billion kilowatthours in 2030 in the *AEO2007* reference case.

In the *AEO2008* reference case, the natural gas share of electricity generation (including generation in the end-use sectors) remains between 20 percent and 21 percent through 2017 before falling to 14 percent in 2030. The coal share remains between 48 percent and 49 percent from 2006 through 2018 before increasing to 54 percent in 2030. Additions to coal-fired generating capacity in the *AEO2008* reference case total 104 gigawatts from 2006 to 2030 (as compared with 156 gigawatts in the *AEO2007* reference case), including 4 gigawatts at CTL plants and 29 gigawatts at integrated gasification combined-cycle plants. Given the assumed continuation of current energy and environmental policies in the reference case, CCS technology does not come into use during the projection period.

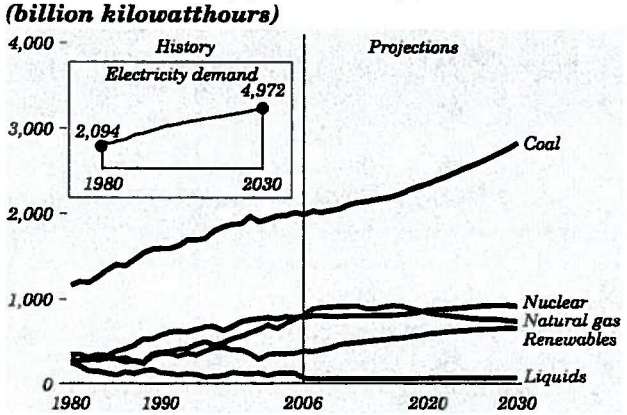
Nuclear generating capacity in the *AEO2008* reference case increases from 100.2 gigawatts in 2006 to 114.9 gigawatts in 2030. The increase includes 17 gigawatts of capacity at newly built nuclear power plants (33 percent more than in the *AEO2007* reference case) and 2.7 gigawatts expected from uprates of existing plants, partially offset by 4.5 gigawatts of retirements.

Rules issued by the Internal Revenue Service in 2006 for the EPACT2005 PTC for new nuclear plants allow the credits to be shared out on a prorated basis to more than 6 gigawatts of new capacity. In the *AEO2008* reference case the credits are shared out to 8 gigawatts of new nuclear capacity, and another 9 gigawatts of capacity is built without credits.

Total electricity generation from nuclear power plants grows from 787 billion kilowatthours in 2006 to 917 billion kilowatthours in 2030 in the *AEO2008* reference case, accounting for about 18 percent of total generation in 2030. Additional nuclear capacity is built in some of the alternative *AEO2008* cases, particularly those that project higher demand for electricity or higher fossil fuel prices.

The use of renewable technologies for electricity generation is stimulated by improved technology, higher fossil fuel prices, and short-term extensions of the EPACT2005 tax credits. The reference case also includes State RPS programs for which legislation is in place. Total renewable generation in the *AEO2008* reference case, including CHP and end-use generation, grows by 2.2 percent per year, from 385 billion kilowatthours in 2006 to 656 billion kilowatthours in 2030. The projection for renewable generation in the *AEO2008* reference case, which includes State and regional programs, is significantly higher than the *AEO2007* projection.

Figure 7. Electricity generation by fuel, 1980-2030 (billion kilowatthours)



Energy-Related Carbon Dioxide Emissions

Absent the application of CCS technology (which is not expected to come into use without changes in current policies that are not included in the reference case), CO_2 emissions from the combustion of fossil fuels are proportional to fuel consumption and carbon content, with coal having the highest carbon content, natural gas the lowest, and liquid fuels in between. In the *AEO2008* reference case, the coal share of total energy use increases from 23 percent in 2006 to 25 percent in 2030, while the share of natural gas falls from 22 percent to 20 percent, and the liquids share falls from 40 percent to 37 percent. The combined share of carbon-neutral renewable and nuclear

energy grows from 15 percent in 2006 to 17 percent in 2030.

Taken together, projected growth in the absolute level of primary energy consumption and a shift toward a fuel mix with slightly lower average carbon content cause projected energy-related emissions of CO_2 (Figure 8) to grow by 16 percent from 2006 to 2030—slightly lower than the projected 19-percent increase in total energy use. Over the same period, the economy becomes less carbon-intensive, because the 16-percent increase in CO_2 emissions is about one-fifth of the projected increase in GDP (79 percent), and emissions per capita decline by 5 percent. In the *AEO2008* reference case, projected energy-related CO_2 emissions grow from 5,890 million metric tons in 2006 to 6,851 million metric tons in 2030. By comparison, in the *AEO2007* reference case, energy-related CO_2 emissions were projected to grow by about 35 percent, to 7,950 million metric tons in 2030, reflecting both a higher projection of overall energy use and, to a lesser extent, a different mix of energy sources.

Figure 8. U.S. carbon dioxide emissions by sector and fuel, 1990-2030 (million metric tons)

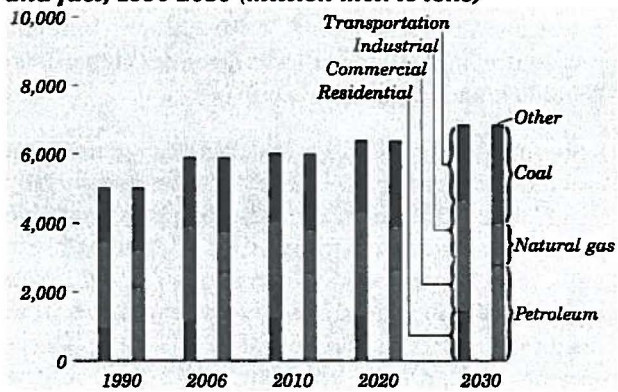


Table 1. Total energy supply and disposition in the *AEO2008* and *AEO2007* reference cases, 2006-2030

Energy and economic factors	2006	2010		2020		2030	
		AEO2008	*AEO2007*	*AEO2008*	*AEO2007*	*AEO2008*	*AEO2007*
Primary energy production (quadrillion Btu)							
Petroleum	13.16	15.03	14.42	15.71	14.85	14.15	13.71
Dry natural gas	19.04	19.85	19.93	20.24	21.41	20.00	21.15
Coal	23.79	23.97	24.47	25.2	26.61	28.63	33.52
Nuclear electricity	8.21	8.31	8.23	9.05	9.23	9.57	9.33
Hydroelectricity	2.89	2.92	3.02	3.00	3.08	3.00	3.09
Biomass	2.94	4.05	4.22	6.42	4.69	8.12	5.26
Other renewable energy	0.88	1.51	1.18	2.00	1.33	2.45	1.44
Other	0.50	0.54	0.67	0.58	0.89	0.64	1.12
Total	**71.41**	**76.17**	**76.13**	**82.21**	**82.09**	**86.56**	**88.63**
Net imports (quadrillion Btu)							
Petroleum	26.69	23.93	25.19	24.03	28.92	26.52	34.74
Natural gas	3.56	3.96	4.67	3.66	5.48	3.28	5.59
Coal/other (- indicates export)	-0.28	-0.84	-0.19	1.06	0.93	1.86	1.57
Total	**29.98**	**27.04**	**29.66**	**28.75**	**35.33**	**31.66**	**41.90**
Consumption (quadrillion Btu)							
Liquid fuels	40.06	40.46	41.76	42.24	46.52	43.99	52.17
Natural gas	22.30	23.93	24.73	24.01	27.04	23.39	26.89
Coal	22.50	23.03	24.24	25.87	27.29	29.90	34.14
Nuclear electricity	8.21	8.31	8.23	9.05	9.23	9.57	9.33
Hydroelectricity	2.89	2.92	3.02	3.00	3.08	3.00	3.09
Biomass	2.50	3.01	3.30	4.50	3.64	5.51	4.06
Other renewable energy	0.88	1.51	1.18	2.00	1.33	2.45	1.44
Net electricity imports	0.19	0.18	0.04	0.17	0.04	0.20	0.04
Total	**99.50**	**103.30**	**106.50**	**110.80**	**118.16**	**118.00**	**131.16**
Liquid fuels (million barrels per day)							
Domestic crude oil production	5.10	5.93	5.67	6.23	5.89	5.59	5.39
Other domestic production	3.19	3.69	4.03	4.46	4.49	4.85	5.08
Net imports	12.45	11.39	11.79	11.36	13.56	12.41	16.37
Consumption	20.65	20.99	21.59	21.96	24.03	22.80	26.95
Natural gas (trillion cubic feet)							
Production	18.57	19.35	19.42	19.73	20.86	19.49	20.61
Net imports	3.46	3.85	4.55	3.55	5.35	3.18	5.45
Consumption	21.66	23.25	24.02	23.33	26.26	22.72	26.12
Coal (million short tons)							
Production	1,177	1,179	1,202	1,281	1,336	1,467	1,704
Net imports	-15	-34	-7	46	41	78	68
Consumption	1,114	1,145	1,195	1,327	1,377	1,545	1,772
Prices (2006 dollars)							
Imported low-sulfur, light crude oil (dollars per barrel)	66.02	74.03	59.23	59.70	53.64	70.45	60.93
Imported crude oil (dollars per barrel)	59.05	65.18	52.76	51.55	47.89	58.66	53.21
Domestic natural gas at wellhead (dollars per thousand cubic feet)	6.42	6.33	5.93	5.44	5.39	6.63	6.16
Domestic coal at minemouth (dollars per short ton)	24.63	26.16	24.94	22.51	22.24	23.32	23.29
Average electricity price (cents per kilowatthour)	8.9	9.2	8.3	8.6	8.1	8.8	8.3
Economic indicators							
Real gross domestic product (billion 2000 dollars)	11,319	12,453	12,790	15,984	17,077	20,219	22,494
GDP chain-type price index (index, 2000=1.000)	1.166	1.26	1.253	1.52	1.495	1.871	1.815
Real disposable personal income (billion 2000 dollars)	8,397	9,472	9,568	12,654	13,000	16,246	17,535
Value of manufacturing shipments (billion 2000 dollars)	5,821	5,997	6,298	7,113	7,779	7,997	9,502
Primary energy intensity (thousand Btu per 2000 dollar of GDP)	**8.79**	**8.30**	**8.33**	**6.93**	**6.92**	**5.84**	**5.83**
Carbon dioxide emissions (million metric tons)	**5,890**	**6,011**	**6,214**	**6,384**	**6,944**	**6,851**	**7,950**

Notes: Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. For nuclear electricity, both production and consumption numbers are based on its fossil-fuel-equivalent energy content.

Sources: AEO2008 National Energy Modeling System, run AEO2008.D030208F; and AEO2007 National Energy Modeling System, run AEO2007.D112106A.

Legislation and Regulations

Legislation and Regulations

Introduction

Because analyses by EIA are required to be policy-neutral, the projections in *AEO2008* are based on Federal and State laws and regulations in effect on or before December 31, 2007. **The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself—are not reflected in the projections.** Throughout 2007, however, at the request of the Administration and Congress, EIA has regularly examined the potential implications of proposed legislation in Service Reports (see box on page 17).

Examples of Federal and State legislation incorporated in *AEO2008* include:

- EISA2007, signed into law on December 19, 2007, which (*a*) includes an expanded RFS requiring the use of 36 billion gallons of ethanol by 2022; (*b*) creates an attribute-based minimum CAFE standard of 35 mpg by 2020 for cars and trucks; (*c*) establishes a program of CAFE credit trading and transfer; (*d*) extends and then phases out the CAFE credits established under the Alternative Motor Fuels Act of 1988 (AMFA); (*e*) creates various appliance efficiency standards; (*f*) establishes a lighting efficiency standard starting in 2012; (*g*) requires industrial electric motors to meet the premium motor efficiency standards of the National Electrical Manufacturers Association (NEMA); and (*h*) creates or enhances a number of other programs related to industrial waste heat or natural gas efficiency, energy use in Federal buildings, weatherization assistance, and manufactured housing (see below for more detailed discussion of the provisions in EISA2007 and their handling in *AEO2008*)
- The provisions of EPACT2005 that remain in effect and have not been superseded by EISA2007, including: mandatory energy conservation standards; numerous tax credits for businesses and individuals; elimination of the oxygen content requirement for Federal reformulated gasoline (RFG); extended royalty relief for offshore oil and natural gas producers; authorization for DOE to issue loan guarantees for new or improved technology projects that avoid, reduce, or sequester GHGs; a PTC for new nuclear facilities; and extension and expansion of the PTC for electricity generated from renewable fuels
- The Military Construction Appropriations Act of 2005, which contains provisions to support construction of the Alaska natural gas pipeline, including Federal loan guarantees during construction
- The Working Families Tax Relief Act of 2004, which includes tax deductions for qualified clean-fuel and electric vehicles and changes in the rules governing oil and natural gas well depletion
- The American Jobs Creation Act of 2004, which includes incentives and tax credits for biodiesel fuels and a modified depreciation schedule for the Alaska natural gas pipeline
- State RPS programs, including the California RPS passed on September 12, 2002
- The Clean Air Act Amendments of 1990 (CAAA-90), which included new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The National Appliance Energy Conservation Act of 1987
- State programs for restructuring of the electricity industry.

Examples of Federal and State regulations incorporated in *AEO2008* include the following:

- The Mobile Source Air Toxics rule released by the EPA on February 9, 2007 (MSAT2), which establishes controls on gasoline, passenger vehicles, and portable fuel containers designed to significantly reduce emissions of benzene and other hazardous air pollutants [7]
- New stationary diesel regulations issued by the EPA on July 11, 2006, which limit emissions of nitrogen oxides (NO_x), particulate matter, sulfur dioxide (SO_2), carbon monoxide, and hydrocarbons to the same levels required by the EPA's nonroad diesel engine regulations.

More detailed information on recent legislative and regulatory developments is provided below.

Energy Independence and Security Act of 2007: Summary of Provisions

The Energy Independence and Security Act of 2007 was signed into law on December 19, 2007, and became Public Law 110-140 [8]. Provisions in EISA2007

EIA Service Reports on Proposed Legislation Released Since January 2007

The table below summarizes the Service Reports on proposed legislation completed since 2007. Those reports, and others that were completed before 2007, can be found on the EIA web site at www.eia.doe.gov/oiaf/service_rpts.htm.

Title	*Date of release*	*Requestor*	*Availability on EIA web site (www.eia.doe.gov/oiaf/servicerpt/)*	*Focus of analysis*
Analysis of Crude Oil Production in the Arctic National Wildlife Refuge	*May 2008*	*Senator Ted Stevens*	*anwr/index.html*	*Provides an assessment of Federal oil and natural gas leasing in the coastal plain of the Arctic National Wildlife Refuge (ANWR) in Alaska.*
Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007	*April 2008*	*Senators Joseph Lieberman, John Warner, John Barrasso, James Inhofe, and George Voinovich*	*s2191/index.html*	*S. 2191 is a complex bill regulating emissions of GHGs through market-based mechanisms, energy efficiency programs, and economic incentives. This analysis focuses on the impacts of the GHG cap-and-trade program established under Title I of S. 2191.*
Federal Financial Interventions and Subsidies in Energy Markets 2007	*April 2008*	*Senator Lamar Alexander*	*subsidy2/index.html*	*Update to 1999 to 2000 EIA work on Federal energy subsidies, including any additions or deletions of Federal subsidies based on Administration or Congressional action since 2000, and providing an estimate of the size of each current subsidy. Subsidies directed to electricity production are estimated on the basis of generation by fuel.*
Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007	*January 2008*	*Senators Jeff Bingaman and Arlen Specter*	*lcea/index.html*	*S. 1766 establishes a mandatory GHG allowance program to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and at least 60 percent below 1990 levels by 2050.*
Oil and Natural Gas Market Supply and Renewable Portfolio Standard Impact of Selected Provisions of H.R. 3221	*December 2007*	*Representatives Joe Barton, Jim McCrery, and Don Young*	*bmy/index.html*	*Analyze selected provisions of H.R. 3221, the energy bill adopted by the House of Representatives (H.R.) in early August 2007. The analysis focuses on Title VII, dealing with energy on Federal lands; Section 9611, which would establish a Federal renewable portfolio standard for certain electricity sellers; and Section 13001, which would eliminate the eligibility of oil and natural gas producers and refiners to claim deductions under Section 199 of the Internal Revenue Code.*
Supplement to: Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007	*November 2007*	*Senators John Barrasso, James Inhofe, and George Voinovich*	*biw/index.html*	*Further energy and economic analysis to supplement information presented in EIA's recent analysis of S. 280, the Climate Stewardship and Innovation Act of 2007.*
Energy and Economic Impacts of Implementing a 25-Percent Renewable Portfolio Standard and Renewable Fuel Standard by 2025	*September 2007*	*Senator James Inhofe*	*eeim/index.html*	*Analysis of a "25-by-25" proposal that combines a requirement that a 25-percent share of electricity sales be produced from renewable sources by 2025 with a requirement that a 25-percent share of liquid transportation fuel sales also be derived from renewable sources by 2025. The electricity requirement is implemented as a renewable portfolio standard, while the motor fuel standard is implemented as an RFS.*
Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007	*July 2007*	*Senators Joseph Lieberman and John McCain*	*csia/index.html*	*Estimate of the economic impacts of S. 280, the Climate Stewardship and Innovation Act of 2007. S. 280 would establish a series of caps on GHG emissions starting in 2012 followed by increasingly stringent caps beginning in 2020, 2030, and 2050.*

(continued on page 18)

that require funding appropriations to be implemented, whose impact is highly uncertain, or that require further specification by Federal agencies or Congress are not included in *AEO2008*. For example, EIA does not try to anticipate policy responses to the many studies required by EISA2007, nor to predict the impact of research and development (R&D) funding authorizations included in the bill. Moreover, *AEO2008* does not include any provision that addresses a level of detail beyond that modeled in NEMS, which was used to develop the *AEO2008* projections. *AEO2008* addresses only those provisions in EISA2007 that establish specific tax credits, incentives, or standards, including the following:

- RFS requirements for the use of 36 billion gallons of ethanol per year by 2022, with corn ethanol limited to 15 billion gallons. Any other ethanol or biodiesel may be used to fulfill the balance of the mandate, but the balance must include 16 billion gallons per year of cellulosic ethanol by 2022 and 5 billion gallons per year of biodiesel by 2012.
- A new CAFE standard for LDVs (cars and light trucks) of 35 mpg by 2020. The Act also specifies that vehicle attribute-based standards are to be developed separately for cars and light trucks.
- A CAFE credit and transfer program among manufacturers and across a manufacturer's fleet.
- Extension through 2019 of the CAFE credits specified under the AMFA. EISA2007 reduces the maximum credit by 0.2 mpg for each model year after 2014 and phases it out entirely by model year 2020.
- Appliance energy efficiency standards for boilers, dehumidifiers, dishwashers, clothes washers, external power supplies, and commercial walk-in coolers and freezers.
- Lighting energy efficiency standards for general-service incandescent lighting in 2012 and sooner for general-service tubular fluorescent lighting and metal halide lamp fixtures.
- Standards for industrial electric motor efficiency, requiring industrial motors of various sizes to meet the NEMA premium motor efficiency standards.
- Standards for energy use in Federal buildings, requiring a 30-percent reduction by 2015.

The following discussion provides a summary of the EISA2007 provisions included in *AEO2008* and some of the provisions that could be included if more

EIA Service Reports on Proposed Legislation Released Since January 2007 (continued)

Title	*Date of release*	*Requestor*	*Availability on EIA web site (www.eia.doe.gov/oiaf/servicerpt/)*	*Focus of analysis*
Impacts of a 15-Percent Renewable Portfolio Standard	*June 2007*	*Senator Jeff Bingaman*	*prps/index.html*	*Analysis of a renewable portfolio standard requiring that 15 percent of U.S. electricity sales be derived from qualifying renewable energy resources.*
Analysis of Alternative Extensions of the Existing Production Tax Credit for Wind Generators	*May 2007*	*Ms. Janice Mays, Chief Counsel, Committee on Ways & Means, U.S. House of Representatives*	*ptc/index.html*	*Analysis of alternative extensions of the existing PTC that would apply to wind generators only.*
Energy Market Impacts of a Clean Energy Portfolio Standard - Follow-up	*February 2007*	*Senator Norman Coleman*	*portfolio/index.html*	*Analysis of a proposed clean energy portfolio standard (CEPS). The proposed CEPS requires electricity suppliers to increase their share of electricity sales that is generated using clean energy resources, including: nonhydropower renewable resources, new hydroelectric or nuclear resources, fuel cells, and fossil-fired plants that capture and sequester CO_2 emissions.*
Energy Market and Economic Impacts of a Proposal to Reduce Greenhouse Gas Intensity with a Cap and Trade System	*January 2007*	*Senators Jeff Bingaman, Mary Landrieu, Lisa Murkowski, Arlen Specter, Ken Salazar, and Richard Lugar*	*bllmss/index.html*	*Analysis of the impacts of a proposal that would regulate emissions of GHGs through an allowance cap-and-trade system. The program would set the cap to achieve a reduction in emissions relative to economic output, or GHG intensity.*

complete information were available about their funding and implementation. This discussion is not a complete summary of all the sections of EISA2007. More extensive summaries are available from other sources [9].

End-Use Demand

Buildings Sector

EISA2007 affects residential and commercial buildings in three specific areas: appliance and lighting energy efficiency, energy savings in private-sector buildings and industry, and energy savings in government and public institutions.

Appliance and Lighting Energy Efficiency. Subtitles A and B in Title III of EISA2007 include provisions with the potential to affect energy demand in the buildings sector. Many of the provisions give DOE the authority to set new efficiency standards or test procedures for new efficiency standards. Where EISA2007 specifies both efficiency levels and effective dates in the standards, they are implemented directly in the NEMS buildings modules. Where specific appliances and future DOE updates to the standards are not specified, they are not included in *AEO2008*.

Section 301 provides efficiency standards for external power supplies, limiting wattage in both active and no-load mode for units produced after July 1, 2008. DOE is instructed to review the standards in the future, but only the 2008 standard is included in *AEO2008*. Section 303 increases the Federal efficiency standard for residential boiler units manufactured after September 1, 2012, providing a small increase (less than 5 percent) over the current standard. Dehumidifiers, clothes washers, and dishwashers are subject to new standards between 2010 and 2012, as provided in Section 311. Energy conservation standards for walk-in refrigerators and walk-in freezers established in Section 312 require energy-efficient elements in the doors, walls, motors, and lighting of units manufactured in 2009 or later. Section 313 amends electric motor efficiency standards, and Section 314 adds single-package vertical air conditioners and heat pumps to the packaged air conditioning and heating equipment covered by the standards in EPACT2005. These two provisions address a level of detail that is not modeled in NEMS, and they are not included in *AEO2008*.

The largest projected energy savings from EISA2007 are the result of energy conservation standards for efficient light bulbs described in Sections 321, 322, and 324. Section 321 requires significant wattage reductions (approximately 28 percent) in incandescent lamps beginning in 2012, increasing to a reduction of about 65 percent in 2020. Section 322 sets standards for general-service fluorescent lamps and incandescent reflector lamps, and Section 324 imposes minimum ballast efficiency standards for metal halide lamp fixtures beginning in 2009. Section 323 mandates the use of energy-efficient lighting fixtures and bulbs to the maximum extent feasible in all Federal buildings starting in 2009.

Energy Savings in Buildings and Industry. Provisions under EISA2007 Title IV, Subtitle A, address energy efficiency in residential buildings. Section 411 reauthorizes funding for weatherization programs through fiscal year (FY) 2012; however, the program has been targeted for elimination by DOE in its most current budget and therefore is not included in *AEO2008*. Section 413 requires manufactured housing to comply with the most recent version of the International Energy Conservation Code (IECC) starting in 2012. This provision is included in *AEO2008*. The 2006 version of the IECC represents the most recent code.

Provisions under Title IV, Subtitle B, establish an office and a partnership consortium to promote high-performance green building initiatives. Section 422 specifically directs the establishment of a Zero Net Energy Commercial Buildings Initiative, with the eventual goal of having all U.S. commercial buildings use zero net energy by 2050. The provision includes several research, development, and deployment activities and authorizes funding for the initiative through 2018. Because the activities depend on future appropriations, they are not included in *AEO2008*.

Title IV, Subtitle C, addresses Federal energy use, updating energy intensity reduction goals and performance standards for Federal buildings, mandating energy and efficiency management, providing for the development of high-performance green building standards for Federal facilities, and directing the establishment of a program to accelerate Federal use of cost-effective technologies and practices. Federal purchasing requirements for energy intensity reduction and performance standards are represented in *AEO2008* as a result of earlier Executive Orders and legislation. Other aspects of these provisions either address a level of detail that is not modeled in *AEO2008* or are not included because they depend on future appropriations.

Provisions under the other Subtitles of Title IV address data center efficiency, environmental quality in schools, and sustainability and efficiency grants and loans for institutions. These provisions are not included in *AEO2008*, because they depend on future appropriations or address a level of detail that is not modeled in NEMS.

Energy Savings in Government and Public Institutions. Title V contains a variety of provisions, including promotion of efficiency and environmental measures for the Capitol complex; promotion and permanent authorization of energy savings performance contracts; standards for Federal purchase of specific technologies; and authorization for funding of State energy programs, utility efficiency incentives, and local energy efficiency block grants. Federal purchasing requirements governing purchases of cost-effective energy-efficient products are represented in *AEO2008* as a result of earlier Executive Orders and legislation. The provisions in EISA2007 Title V are not included in *AEO2008*, because they depend on future appropriations or address a level of detail that is not modeled in NEMS.

Industrial Sector

EISA2007 includes several provisions in Titles III and IV that could affect energy demand in the U.S. industrial sector; however, provisions in Title VI, Accelerated Research and Development, that may affect industrial energy consumption over the long term are not included in *AEO2008*.

Section 313 of Title III increases or creates minimum efficiency standards for newly manufactured general-purpose electric motors that must be met within 3 years of enactment (Table 2). Efficiency standards for general-purpose, integral-horsepower induction motors are raised, with the exception of fire pump motors. Minimum standards are created for seven types of poly-phase, integral-horsepower induction motors and NEMA design B motors (201 to 500 horsepower) not covered under the previous standards in the Energy Policy Act of 1992 (EPACT1992). These standards are included in *AEO2008* for industrial motor additions.

Table 2. Representative efficiency standards for enclosed motors (percent)

Horsepower	EPACT1992	EISA2007
1	82.5	85.5
5	87.5	89.5
20	91.0	93.0
50	93.0	94.5
100	94.5	95.4
200	95.0	96.2
500	—	96.2

Sections 451, 452, and 453 direct the EPA to survey all major industrial combustion sources and create a registry of the quantity and quality of waste energy at each site. DOE may provide up to 50 percent of the funding for a feasibility study to determine whether the waste heat can be captured with a 5-year payback. In addition, DOE is authorized to provide grants of nearly $200 million per year to industrial partnerships for research on energy savings. Finally, these sections create a program that collects best practices, designs, processes, and innovations for building energy-efficient data centers. These provisions are not funded and are not included in *AEO2008*.

Transportation Sector

EISA2007 Title 1, Section 102, requires that the average manufacturer's fleet fuel economy for cars and light-duty trucks be increased, starting in 2011, to an average of 35 mpg by 2020, based on the EPA test value used to measure compliance with the CAFE standard. The EPA CAFE test value generally differs from the estimated mpg value on the fuel economy label and, typically, exceeds the actual on-the-road fuel economy of a new vehicle by a significant margin. For model years 2021 through 2030, Section 102 specifies that the average fuel economy must be set at the maximum feasible average for each fleet. In *AEO2008*, fuel economy standards for LDVs are assumed to remain at the 2020 level. *AEO2008* includes attribute-based fuel economy standards for light trucks, given vehicle footprint [*10*] and sales share. It uses these fuel economy curves to achieve the overall fleet fuel economy standard of 35 mpg. The fuel economy standards for cars are not attribute-based, but they apply to the manufacturer's fleet of both domestic and imported vehicles. In *AEO2008*, the fuel economy standard for cars is assumed to increase from 27.5 mpg in 2010 to 41.0 mpg in 2020. For light trucks, the footprint-based average fleet fuel economy standard increases from 24.0 mpg in 2011 to 31.0 mpg in 2020.

Section 103 requires the development of fuel economy standards for work trucks—8,500 pounds to less than 10,000 pounds gross vehicle weight rating (GVWR)—and commercial medium- and heavy-duty on-highway vehicles (GVWR 10,000 pounds or more). The new fuel economy standards require consideration of vehicle attributes and duty requirements and can

prescribe standards for different vehicle classes, such as buses used in urban operation or semi-trucks used primarily in highway operation. Section 103 provides a minimum lead time of four full model years before the new fuel economy standard is adopted, and a minimum of three full model years after the new fuel economy standard has been established before the fuel economy standards for work trucks can be modified. Because these fuel economy standards are pending, and because NEMS currently does not model fuel economy regulations for work trucks or commercial medium- and heavy-duty vehicles, this aspect of EISA2007 is not included in *AEO2008*.

Section 104 establishes a fuel economy credit trading program. Currently, CAFE credits earned by manufacturers can be banked for up to 3 years and can be applied only to the fleets (car or light truck) from which the credits were earned. Starting in model year 2011, the credit trading program will allow manufacturers whose vehicles exceed the minimum fuel economy standards to earn credits that can be sold to other manufacturers whose vehicles fail to achieve the prescribed standards. The credit trading program is designed to ensure that the total fuel savings for manufacturers exceeding the prescribed standards are preserved when credits are sold to manufacturers not achieving the standards.

The credit trading program begins in 2011, and EISA2007 allows manufacturers to apply credits earned to any of the three model years before the model year for which they are earned and to any of the five model years after the credits are earned. Credit transfers within a manufacturer's fleet are limited to specific maximums: 1.0 mpg for model years 2011 through 2013, 1.5 mpg for model years 2014 through 2017, and 2.0 mpg for model years 2018 and later. NEMS currently allows for sensitivity analysis of CAFE credit banking by manufacturer fleet but does not model the trading of credits among different manufacturers. Consequently, *AEO2008* does not include trading of fuel economy credits.

Section 109 extends the CAFE credits specified under AMFA through 2019. Before the passage of EISA-2007, the CAFE credits under AMFA were scheduled to expire after model year 2010. Currently, 1.2 mpg is the maximum CAFE credit that can be earned for selling alternative-fuel vehicles. EISA2007 extends the 1.2 mpg credit maximum through 2014 and reduces the maximum by 0.2 mpg for each following year until it is phased out by model year 2020. NEMS currently does not model CAFE credits earned from alternative-fuel vehicles sales, and *AEO2008* does not consider this section of EISA2007.

Petroleum, Ethanol, and Biofuels

This section summarizes the numerous provisions of EISA2007 affecting the supply, composition, and refining of petroleum and related products that are included in *AEO2008*.

Renewable Fuels Standard

EISA2007 Title II, in Subtitles A and B, includes an updated RFS that increases the requirement for total U.S. consumption of renewable fuels from the 7.5 billion gallons in 2012 as specified in EPACT2005 to 36 billion gallons in 2022. Mandates are set for specific types of renewable fuels, including both conventional biofuels (corn-based ethanol) and advanced biofuels that are not derived from corn starch (such as cellulosic ethanol, butanol, or diesel products and biomass-based diesel [*11*].

The advanced biofuel requirement comes into effect in 2009 at 0.6 billion gallons and rises to 21 billion gallons in 2022. In 2015 and thereafter, the maximum amount of corn-based ethanol that can be applied to the overall RFS is 15 billion gallons. The cellulosic biofuel requirement starts in 2010 at 0.1 billion gallons and rises to 16 billion gallons in 2022. The biomass-based diesel requirement begins at 0.5 billion gallons in 2009 and rises to 1 billion gallons in 2012, with the remaining years to be determined by the EPA Administrator.

EISA2007 also establishes a life-cycle GHG standard for biofuels. The GHG standard for all biofuels is based on the 2005 emission level for the particular type of transportation fuel. Corn-based ethanol must achieve a 20-percent reduction in life-cycle GHG emissions, which would disqualify future corn ethanol production facilities that use coal for process heat. In addition to being defined as not being derived from corn starch, advanced biofuels are further defined as any renewable fuels that reduce emissions by at least 50 percent. Finally, 60 percent or more of the reduction in emissions must be achieved before any cellulosic biofuel can qualify under that category.

Given uncertainty about whether the new RFS schedule can be achieved, EISA2007 contains a general waiver based on technical, economic, or environmental feasibility. In addition, the cellulosic biofuel

mandate includes a credit program that is activated only in years when the mandated level of cellulosic biofuel is judged by the EPA Administrator as unlikely to be met. For all the fuel mandates, if there is a 20-percent deficit in more than two consecutive years or a 50-percent deficit in any one year, regulatory adjustment mechanisms are provided to lower the mandated levels from that point forward. This rule, which could be enacted by the EPA Administrator no sooner than 2016, would modify all applicable volumes (including the overall and advanced biofuel totals) for all subsequent years.

The RFS is included in *AEO2008*, with cellulosic biofuel credit and waiver provisions that are consistent with those in the existing law. Actual renewable fuel supplies in any year are allowed to exceed the minimum RFS requirements, depending on the availability of technology and feedstocks and the relative costs of renewable fuels and competing petroleum products. Because the RFS does not explicitly specify the level of the mandate after 2022, *AEO2008* assumes that it will remain at the 2022 level through 2030.

In order to achieve the biofuel consumption levels mandated in EISA2007, significantly more biofuels must be consumed than can be blended into gasoline as E10. Other than requiring studies involving ethanol pipelines and similar infrastructure issues, EISA2007 does not directly provide for infrastructure improvements that may be necessary. In *AEO2008*, the amount of ethanol in excess of what can be consumed in E10 is assumed to be used in E85. Flexible-fuel vehicles are assumed to be available in sufficient numbers to use the required amounts of E85, and E85 distribution infrastructure is assumed to be built over a technically practicable period. The infrastructure development costs are spread across all transportation fuels.

E85 infrastructure costs potentially could be reduced if biobutanol or ethanol-gasoline blends containing more than 10 percent ethanol (other than E85) were able to meet a significant portion of the RFS; however, *AEO2008* assumes that neither will actually contribute to meeting the EISA2007 mandates. At present there is little commercial activity for biobutanol, and only a few tests are under way [*12*]. Automakers and engine manufacturers are concerned about ethanol-related problems in vehicles built to run on gasoline blends no higher than E10, because higher ethanol blends are corrosive to engines not designed to handle them, and their use could adversely affect performance and cause vehicle warranties to be voided [*13*].

Amortization of Geological and Geophysical Expenditures

EISA2007 extends the 5-year amortization period for geological and geophysical expenditures by major integrated oil companies to 7 years as of the enactment of the bill. Because the NEMS oil and gas supply model does not directly represent geological and geophysical expenditures, this change is not included in *AEO2008*.

Electricity

EISA2007 includes few provisions that affect electricity generation or transmission. Title XIII, Smart Grid, promotes a modernization of the electricity transmission and distribution system to strengthen reliability and energy efficiency. Funding is provided for research and demonstration projects, as well as matching funds for qualifying investments. States are to encourage, but not require, utilities to adopt smart grid technology and allow them to recover their costs through rate increases. The bill does not include enough specific information to support NEMS projections of changes in investment or prices for electricity transmission and distribution, but it is implicitly assumed in *AEO2008* that electricity will be provided reliably.

Coal

Industries that rely on coal could benefit from EISA2007 Title VII, Carbon Capture and Sequestration, if CO_2 emissions are restricted in the future. Sections 702 through 711 expand authorized funding and provide greater detail on the carbon capture and development program originally established in EPACT2005, Section 963. EISA2007 Sections 702 through 711 are not included in *AEO2008*, because the authorized funds have not been appropriated and the effects of the included research, development, and other projects are uncertain.

Section 702 authorizes $240 million per year from 2008 through 2012 for carbon sequestration projects, an increase from the amount authorized in EPACT2005. Among the R&D programs supported under Section 702 are the development of a minimum of seven large-scale geologic sequestration projects, with each project capable of injecting at least 1 million tons of CO_2 annually. Geologic formations

that potentially could be used for sequestration include operating or depleted oil and natural gas fields, unmineable coal seams, deep saline or basalt formations, and deep geologic resources from which economical geothermal heat is extracted. Monitoring, mitigation, and verification of CO_2 containment are also required under Section 702.

Section 703 authorizes additional funding of $200 million per year from 2009 through 2013 for R&D projects focused on capture, purification, compression, transportation, and injection of CO_2 emitted from industry sources. In the decision to undertake Section 703 projects, the Secretary of Energy may prioritize projects that include sequestration programs described under Section 702; however, integration is not a requirement for funding. As noted above, these R&D provisions are not included in *AEO2008*.

Section 706 recognizes that the CCS program must adhere to the Safe Drinking Water Act. Additional provisions in EISA2007 authorize funds for the education and training of individuals to work in the CCS field. None of these provisions is specifically reflected in *AEO2008*.

Section 711 requires the Secretary of the Interior and the Director of the United States Geological Survey (USGS) to develop an assessment of the potential, including geographical extent and capacity, of geologic formations to sequester carbon. The Secretary of Energy and the Secretary of the Interior are further charged with the responsibility for creating a database of possible sequestration sites, ranked by capacity and risk. Section 711 authorizes total funding of $30 million from 2008 through 2012. This section does not pertain directly to *AEO2008* and is not included.

Renewable Energy

In addition to the renewable energy provisions affecting the transportation, industrial, and buildings sectors, EISA2007 contains provisions authorizing several R&D programs for renewable energy use in the electric power sector. Specifically, Title VI calls for renewed, new, or enhanced R&D, educational, and technology transfer programs in the areas of solar energy (Sections 601-607), geothermal energy (Sections 611-625), and marine and hydrokinetic energy (Sections 631-636). Section 656 authorizes the Renewable Energy Innovation Manufacturing Partnership to advance manufacturing methods that use renewable energy. Appropriations for the authorized programs are not provided in the bill, however, and the programs are not included in *AEO2008*.

Other titles in EISA2007 contain provisions directly related to renewable electricity generation, but they either call for programs to be established or require specific appropriations that have not been made and, therefore, are not included in *AEO2008*. Section 803 authorizes direct grants for eligible renewable energy development projects. Section 806 is a nonbinding "sense of the Congress" statement that the Nation should strive to achieve a 25-percent renewable share of total energy consumption by 2025, while also providing sufficient food, feed, and fiber from agricultural resources. This statement does not contain any enforceable provisions or require any specific policy actions. Section 807 requires the Secretary of Interior to compile a comprehensive assessment of domestic geothermal resources. Section 1002 calls for the establishment of a workforce training program for trades related to renewable and energy efficiency. Section 1201 establishes a loan program for small businesses that want to purchase renewable energy or energy efficiency systems. Section 1207 establishes a program to support venture capital funding for new renewable energy businesses.

Federal Fuels Taxes and Tax Credits

The *AEO2008* reference case incorporates current regulations that pertain to the energy industry. This section describes the handling of Federal taxes and tax credits in *AEO2008*, focusing primarily on areas where regulations have changed or the handling of taxes or tax credits has been updated.

Excise Taxes on Highway Fuel

The handling of Federal highway fuel taxes remains unchanged from *AEO2007* [*14*]. Gasoline is assumed to be taxed at 18.4 cents per gallon, diesel at 24.4 cents per gallon, and kerosene jet fuel at 4.4 cents per gallon [*15*]. Taxes are not adjusted for inflation and remain at the same nominal values throughout the projections. State fuel taxes are calculated on the basis of a volume-weighted average of gasoline, diesel, and jet fuels sold. The handling of State fuel taxes was updated as of July 2007 [*16*].

Biofuels Tax Credits

The most significant change for *AEO2008* is in the handling of Federal fuels taxes and credits that

pertain to biofuels. Several Federal tax credits are available for liquid fuel blenders who blend ethanol into gasoline or biodiesel into diesel fuel or heating oil. Under the Volumetric Ethanol Excise Tax Credit (VEETC) [*17*], blenders are eligible for a tax credit of $0.51 per gallon of ethanol blended. Thus, the tax credit is equal to $0.051 per gallon for E10 and $0.434 per gallon for E85 [*18*]. The credit is scheduled to expire at the end of 2010. Biodiesel also receives a tax credit under VEETC, equal to $1.00 per gallon for "agri-biodiesel" and $0.50 per gallon for "waste-grease biodiesel" made from recycled vegetable oils and animal fats. Currently, the credits are scheduled to expire in 2008 [*19*, *20*]. In *AEO2008*, both tax credits are assumed to expire according to the provisions of existing laws [*21*].

EPACT2005 provides small producers of ethanol, up to 60 million gallons [*22*], with an income tax credit of $0.10 per gallon on production volumes up to 15 million gallons. Because the credit affects only a small portion of the overall ethanol supply and is scheduled to expire on December 31, 2008, it is not included in *AEO2008*.

Ethanol Import Tariff

Two duties currently are imposed on imported ethanol. The first is an *ad valorem* tariff of 2.5 percent; the second is a tariff of $0.54 per gallon, which is applied after the *ad valorem* tariff. The second tariff, which was set to expire in October 2007 but has been extended to January 1, 2009, allows for limited duty-free imports from designated Central American and Caribbean countries, not exceeding 7 percent of domestic production in the previous year. In the *AEO2008* projections, ethanol imports increase after the tariff expires.

Production Tax Credits for Renewable Electricity Production

The handling of the Federal PTC for renewable electricity has been updated for *AEO2008* to be consistent with current legislation. The PTC, which was set to expire on December 31, 2007, was extended to December 31, 2008, by the Tax Relief and Health Care Act of 2006, Public Law (P.L.) 109-432. It provides a benefit of $0.020 per kilowatthour (real 2007 dollars) for the first 10 years of an eligible renewable energy facility's operation, boosting the growth of U.S. wind capacity in the near term. In the *AEO2008* reference case, wind capacity in the electric power sector grows from 15.9 gigawatts in 2007 to 20.2 gigawatts in 2008, as compared with the *AEO2007* projection of 16.6 gigawatts in 2008.

Mobile Source Air Toxics Rule

On February 9, 2007, the EPA released its MSAT2 rule, which will establish controls on gasoline, passenger vehicles, and portable fuel containers. The controls are designed to reduce emissions of benzene and other hazardous air pollutants [*23*]. Benzene is a known carcinogen, and the EPA estimates that mobile sources produced more than 70 percent of all benzene emissions in 1999. Other mobile source air toxics, including 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, and naphthalene, also are thought to increase cancer rates or contribute to other serious health problems. The MSAT2 rule sets a revised specification for benzene, which will take effect in 2011. The regulations on passenger vehicles, which will control hydrocarbon emissions in colder temperatures, will be implemented from 2010 to 2015. The rule also sets more stringent controls on portable fuel containers, beginning in 2009.

The MSAT2 rule has been included in *AEO2008* by modifying the NEMS representation of refinery processing of catalytic reformer feed. Although virtually every refinery will meet the requirement in a different way, most will involve treatment of the feed or product or the operation of the catalytic reformer.

Beginning on January 1, 2011, all gasoline products (including both reformulated and conventional gasoline) produced at refineries will be required to contain no more than 0.62 percent benzene by volume. (This does not apply to gasoline produced or sold in California, which is already covered by the current California Phase 3 Reformulated Gasoline program.) Approved small refineries will be required to conform to the rule by 2015. The second part of the standard requires that the *actual* average benzene levels that each refinery produces be no greater than 1.3 percent by volume by July 1, 2012 (July 1, 2016 for small refiners). The actual level is the level reached without use of any credits.

The published rule for gasoline benzene control includes an averaging, banking, and trading (ABT) program that is consistent with past EPA fuel regulations, allowing refiners to choose the most economical compliance strategy to meet the 0.62-percent annual average standard either by investing in new technology or by buying credits from the ABT program. From 2007 to 2010, the ABT program allows refiners

to build "early credits" by making qualifying benzene reductions earlier than required. In 2011 and beyond, refiners and importers can generate "standard credits" by producing or importing gasoline with benzene levels below 0.62 volume percent on an annual average basis. The credits will be interchangeable between refiners and importers nationwide and can be "banked" for future use. The 3-year lag following establishment of the credit program provides the time necessary for small refiners to finish capital projects that are needed to meet the new standards without relying on credits. The rule also establishes a temporary hardship provision, which will provide refiners and importers with temporary relief from the benzene standards under certain rare circumstances (such as a refinery fire or natural disaster).

EPACT2005 Loan Guarantee Program

Title XVII of EPACT2005 authorized DOE to issue loan guarantees for projects involving new or improved technologies to avoid, reduce, or sequester GHGs. The law specified that the amount of the guarantee would be up to 80 percent of a project's cost. EPACT2005 also specified that DOE must receive funds equal to the "subsidy cost" either through the Federal appropriations process or from the firm receiving the guarantee [*24*]. As discussed in *AEO2007*, this program, by lowering borrowing costs, can have a major impact on the economics of capital-intensive technologies [*25*].

In August 2006, DOE announced its first solicitation for $2 billion in loan guarantees. Even though the entire subsidy costs would be paid by successful applicants, DOE believed that authorization from Congress in an appropriations bill was required, and because there was no such authorization at the time, the requests were considered "pre-applications." Consequently, the effects of the solicitation were not included in *AEO2007*. In February 2007, DOE did receive authorization to issue a total of $4 billion in guarantees. To codify DOE's view that authorization is needed, the omnibus appropriations bill for FY 2008 passed by Congress in December 2007 (H.R. 2764) and its accompanying conference report required DOE to submit a loan guarantee implementation plan to both the House and Senate Appropriations Committees for approval 45 days before DOE issues any future solicitations.

The conference report also directed DOE "to make no authority in excess of" $38.5 billion for FY 2008 and FY 2009 [*26*] and allocated the $38.5 billion cap as follows: $18.5 billion for nuclear plants; $6 billion for carbon capture technologies; $2 billion for advanced coal gasification units; $2 billion for "advanced nuclear facilities for the 'front end' of the nuclear fuel cycle"; and $10 billion for technologies related to renewables, energy conservation, distributed energy, and electricity generation, transmission, and distribution.

The guidelines that accompanied the August 2006 solicitation—which stated that DOE would only guarantee up to 80 percent of a project's *debt*—were criticized by some in the investment community and the nuclear industry for failing to take maximum advantage of the loan guarantee provision in EPACT-2005, which allows DOE to guarantee up to 80 percent of a project's cost [*27*]. The final rule that formalized the guidelines, issued in October 2007, allows for up to 100 percent of the project debt to be guaranteed. This approach was codified in EISA2007.

Because future solicitations have not yet been issued and remain subject to approval of a loan guarantee implementation plan by the Appropriations Committees, only the effects of the August 2006 solicitation are included in *AEO2008*. Table 3 summarizes the number of applications and the requested amounts that could be guaranteed for various technologies in the solicitation. In total, DOE received 143 applications for $27 billion in loan guarantees for projects costing $51 billion [*28*]. In October 2007, DOE released information about the 16 projects and sponsors that will be invited to submit full applications. Because the final approval process will take some time, *AEO2008* assumes that the dollar amount of the approved guarantees will be roughly proportional to the requested guarantees. Accordingly, *AEO2008* includes an additional 1.2 gigawatts of capacity at advanced coal-fired power plants and 250 megawatts at solar power plants that are built as a result of the loan program. (The other projects in the October 2007 announcement were for technologies that are outside the scope of *AEO2008*.)

State Renewable Energy Requirements and Goals: Update Through 2007

In recent years, the *AEO* has tracked the growing number of States that have adopted requirements or goals for renewable energy. While there is no Federal renewable generation mandate, the States have been adopting such standards for some time. *AEO2005*

provided a summary of all existing programs in effect at that time [*29*], and subsequent *AEOs* have examined new policies or changes to existing ones [*30,31*]. Since the publication of *AEO2007*, four States have enacted new RPS legislation, and five others have strengthened their existing RPS programs. In total, 25 States and the District of Columbia now have mandatory RPS programs (Table 4). At least four other States—Missouri, North Dakota, Vermont, and Virginia—have voluntary renewable energy programs.

All mandatory State RPS programs enacted as of the end of 2007 are represented in the *AEO2008* reference case. While States differ in aspects such as eligible generation technologies and compliance penalties, a regional representation was created for modeling purposes. With the exception of California and New York, where eligible future renewable generation is uncertain because of funding limitations for State-supported programs, all States were assumed to meet their program targets, consistent with regionally aggregated compliance schedules. EIA estimated compliance generation in California and New York based on regional costs and authorized funding levels. In estimating diverse State mandates on a regional level, some precision is lost; however, including the State RPS programs in the reference case results in a better projection that is more consistent with current legislation and regulation. If recent trends continue, the State RPS programs will exert growing influence over the national energy mix.

Four States enacted new mandatory RPS programs over the past year:

New Hampshire. In May 2007, the State enacted an RPS which requires that the renewable share of energy consumed for electricity generation increase through 2025, reaching nearly 24 percent by 2025 [*32*]. Approximately 16 percent of all electricity sales must be from renewable facilities that begin operation after 2006. New Hampshire will collaborate with the New England control area to establish a renewable energy certificate (REC) program. Eligible generation must occur within New England or be consumed by costumers in the area. In this legislation, different renewable technologies are given distinct classifications with minimum generation requirements and compliance penalties. Solar power, which has the highest compliance penalty, must make up 0.3 percent of total sales by 2015 to reach the mandate.

North Carolina. The State established an RPS in August 2007 with different targets for investor-owned utilities, municipal suppliers, and electric cooperatives [*33*]. Investor-owned utilities must generate 12.5 percent of their total electric sales from renewable generation sources by 2021. Until 2018, one-quarter of this requirement can be met through the implementation of energy efficiency technologies. After 2018, 40 percent of the requirement can be met through the use of energy efficiency technologies. Municipal suppliers and electric cooperatives have a renewable mandate of 10 percent of retail electricity sales by 2018. In addition to the energy efficiency provision, municipal suppliers and electric cooperatives may meet a majority of the mandate through demand-side management and the use of large hydroelectric facilities. North Carolina will use an REC market, and limited out-of-State generation qualifies in meeting the RPS.

Oregon. The State enacted an RPS in June 2007, with standards that vary according to the size of the electricity provider [*34*]. Larger utilities must produce 25 percent of their electricity sales from renewable resources by 2025. Medium-sized suppliers have a 10-percent requirement and small providers a 5-percent requirement. Any renewable power plant coming online after 1995 is considered eligible toward meeting the State renewable energy goal. Oregon will use an REC market exclusive to the State, and credits will be capped at a price yet to be determined.

Washington. Voters approved Initiative 937 in November 2006, enacting the Nation's second ballot

Table 3. Summary of DOE's August 2006 loan guarantee solicitation

	Applications		Project costs		Guarantees requested (billion dollars)
Technology	Number	Percent of total	Amount (billion dollars)	Percent of total	
Biomass	*70*	*49*	*6*	*11*	*4*
Advanced fossil fuel	*23*	*16*	*35*	*69*	*16*
Solar	*17*	*12*	*3*	*6*	*2*
Energy efficiency	*9*	*6*	*4*	*7*	*3*
Other	*24*	*17*	*4*	*7*	*2*
Total	***143***	***100***	***52***	***100***	***27***

Table 4. State renewable portfolio standards

State	Program mandate
AZ	ACC Decision No. 69127 requires 15 percent of sales to be renewable by 2025, with interim goals increasing annually. A specific percentage of the target must be from distributed generation. Multiple credits may be given for solar generation and in-State manufactured systems.
CA	Public Utilities Code, Section 399.11-399.20, mandates that 20 percent of sales be renewable by 2010. There are also longer-term goals. Renewable projects with above-market costs will be funded by supplemental energy payments from a limited fund, possibly limiting renewable generation below the 20-percent requirement.
CO	House Bill 1281 strengthened the renewable target to 20 percent by 2020 for investor-owned utilities. There is a 10-percent requirement in the same year for cooperative and municipal utilities. Moreover, 2 percent of total sales by investor-owned utilities must be from solar power. In-State generation receives a 25-percent credit premium.
CT	Public Act 07-242 strengthened the original RPS provisions and mandated a 27-percent renewable sales requirement by 2020. Included in the total is a 4-percent mandate from greater efficiency or CHP systems. Three percent of the overall total may be met from waste-to-energy facilities and conventional biomass.
DE	Senate Bill 19 strengthened the RPS to 20 percent of sales by 2019. There is a separate requirement for solar generation (2 percent of the total), and compliance failure results in higher penalty payments. Solar technologies receive triple credits.
DC	Enacted in 2005, the RPS mandates that 11 percent of sales be renewables by 2022. Some technologies receive bonus credits and awards for early installations of renewable systems.
HI	Senate Bill 3185 amended the RPS to increase the mandate to 20 percent by 2020. All existing renewable facilities are eligible in meeting the target, which has two interim milestones.
IL	Public Act 095-0481 created an agency responsible for overseeing the mandate of 25 percent renewable sales by 2025. There are escalating annual targets, and 75 percent of the requirements must be from wind-generated electricity. The plan also includes a cap on the incremental costs added from renewable penetration.
IA	An RPS mandating 105 megawatts of renewable energy capacity has already been exceeded.
ME	In 2007, Public Law 403 added to the State's RPS requirements. Originally a mandate of 30 percent renewable generation by 2000 was set to be lower than current generation. The new law states that new renewable resource capacity must increase to 10 percent of electricity generation by 2017 and in the subsequent years. The years leading up to 2017 also have new capacity milestones.
MD	Senate Bill 595 revised the RPS to contain a 9.5-percent target by 2022. Moreover, renewable generation technologies are categorized into differing share requirements. Penalty payments for compliance shortfalls were also determined.
MA	The RPS has a 4-percent renewable sales total by 2009 with an optional 1-percent annual increase thereafter (not reflected in AEO2008). The State also imposes penalty payments for compliance shortfalls.
MN	Senate Bill 4 created a 30-percent renewable requirement by 2020 for Xcel, the State's largest supplier, and a 25-percent requirement by 2025 for others. Also specified was the creation of a State cap-and-trade program that will assist the program's implementation.
MT	House Bill 681 expanded the RPS provisions to all suppliers. Initially the law covered only public utilities. A 15-percent share of sales must be renewable by 2015. The State operates an REC market.
NV	Established in 1997 and revised in 2005, the State's escalating target reaches 20 percent by 2015. Up to one-quarter may be met through efficiency measures. There is also a minimum requirement and bonus requirements for solar resources.
NH	House Bill 873 legislated that 23.8 percent of sales must be renewable by 2025. 16.3 percent of total sales must be from renewable facilities that have begun operation after 2006. Compliance penalties vary by generation type.
NJ	In 2006, the RPS was revised to increase renewable energy targets. The current level for renewable generation is 22.5 percent of sales by 2021, with interim targets. There are different requirements for different technologies, including a 2-percent solar mandate.
NM	Senate Bill 418 directs investor-owned utilities to have 20 percent of their sales renewable by 2020. The renewable portfolio must consist of diversified technologies, and wind and solar each must account for 20 percent of the target. There is a separate 10-percent standard by 2020 for cooperatives.
NY	The Public Service Commission issued RPS rules in 2005 that call for renewable sales of 24 percent by 2013, from current levels of 19 percent.
NC	Senate Bill 3 created an RPS of 12.5 percent by 2021 for investor-owned utilities. There is also a 10-percent requirement by 2018 for cooperative and municipal suppliers. Through 2018, one-quarter of the target may be met through efficiency standards; that proportion increases to 40 percent in later years.
OR	In June 2007, Senate Bill 838 required renewable targets of 25 percent by 2025 for large utilities and 5 to 10 percent by 2025 for smaller utilities. Any source of renewable electricity on line after 1995 is considered eligible. Compliance penalty caps have not been determined.
PA	The Alternative Energy Portfolio Standard has an 18-percent requirement by 2020. At least 8 percent of the sales must be renewables, but there is also a provision that allows for certain coal resources to receive credits.
RI	The program requires 16 percent of total sales to be renewable by 2020. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must make an alternative compliance payment.
TX	Senate Bill 20 strengthened the State's RPS to mandate 5,880 megawatts of renewable capacity by 2015. There is also a target of 500 megawatts of renewable capacity other than wind.
WA	Voters approved Initiative 937, which specifies that 15 percent of sales from the State's largest generators must come from renewable sources by 2020. There is an administrative penalty of 5 cents per kilowatthour for noncompliance. Any facility on line after 1999 is eligible.
WI	In March 2006, Senate Bill 459 increased the RPS law to 10 percent of renewable sales by 2015. Requirements vary by supplier, and out-of-State generation is eligible.

RPS [35]. The law covers 84 percent of Washington's sales, affects the State's 17 largest suppliers, and specifies that 15 percent of their electricity load must be generated from renewable energy by 2020. Eligible generation includes any renewable facility that comes on line after 1999. The 17 suppliers also must identity feasible areas of conservation and publish implementation plans to achieve demand reductions. Failure to comply with the RPS or the conservation measures will result in a penalty to the generator of 5 cents per kilowatthour of generation.

Five States significantly changed their existing RPS requirements:

Delaware. The State enacted Senate Bill (S.B.) 19 in July 2007, increasing the required RPS from 10 percent to 20 percent of electricity by 2019 [36]. It also created a solar photovoltaic (PV) provision under which 2 percent of electricity must originate from solar PV by 2019. Both the solar target and the renewable target consist of escalating interim milestones. The existing schedule of alternative compliance payments (ACPs) is not affected [37], but the bill does provide for separate solar ACPs with a minimum value of $250 per megawatthour—much higher than the standard ACPs. In-State solar PV generation receives triple credits toward meeting the RPS.

Colorado. House Bill 1281 strengthened the RPS that was approved by voters in 2004 by increasing the amount of renewable energy required in 2015 from 10 percent to 15 percent of sales [38]. It also added the requirement that 20 percent of total electricity sales by investor-owned utilities must come from renewable energy by 2020. Investor-owned utilities also are required to generate 2 percent of their sales with solar energy technologies. House Bill 1281 created a less stringent standard for electric cooperatives and municipal utilities, requiring that only 10 percent of sales be from qualifying sources by 2020. It also establishes that generation within Colorado receives 125 percent of the value that out-of-State energy would earn.

Connecticut. The State revised its RPS requirement in June of 2007 as part of Public Act 07-242 [39]. The revisions extended the RPS to 2020, with a 27-percent requirement in that year. Most of the standard is to be met through renewable technologies using wind, solar, sustainable biomass, and wave energy. Generation from surrounding States is eligible. There are separate rules requiring CHP systems and efficiency enhancements (4 percent). Three percent of the total may be met from waste-to-heat facilities and conventional biomass. Suppliers that do not comply face a penalty of 5.5 cents that will be used to fund renewable development.

Illinois. In August 2007, the State's voluntary renewable goal was replaced by a mandatory RPS [40]. Suppliers with more than 100,000 customers are required to provide 25 percent of their electricity from qualifying facilities by 2025, with several interim requirements. Three-quarters of the facilities must be wind powered. Until 2011, lower cost in-State resources must be used unless they are proven exhausted, in which case out-of-State generation would qualify. After 2011, no preference is given to Illinois resources over others in the region. The costs associated with the mandates are capped and reviewable.

Minnesota. Minnesota's new RPS regulations became effective in February 2007. They created two standards, one for Xcel Energy and another for other suppliers [41]. Previously, Minnesota had a voluntary standard. The Xcel milestones are the most significant, with 30 percent of all power required to come from renewable energy by 2020. Approximately 83 percent of the power from renewables must come from wind turbines. Other suppliers, including municipal utilities, have until 2025 to meet a smaller goal of 25 percent. The State Public Utilities Commission is still constructing an REC trading system, and the role that interstate or interregional credits will play is still unknown.

State Regulations on Airborne Emissions: Update Through 2007

Implementation of the Clean Air Interstate Rule

States are moving forward with implementation plans for the Clean Air Interstate Rule (CAIR) [42]. The program, promulgated by the EPA in March 2005, is a cap-and-trade system designed to reduce emissions of SO_2 and NO_x. States originally had until March 2007 to submit implementation plans, but the deadline has been extended by another year. CAIR covers 28 eastern States and the District of Columbia. States have the option to participate in the cap-and-trade plan or devise their own plans, which can be more stringent than the Federal requirements. To date, no State has indicated an intent to form NO_x and SO_2 programs with emissions limits stricter than

those in CAIR, and it is expected that all States will participate in the EPA-administered cap-and-trade program. CAIR remains on schedule for implementation, and *AEO2008* includes CAIR by assuming that all required States will meet only the Federal requirement and will trade credits.

A similar program, the Clean Air Mercury Rule (CAMR), was promulgated by the EPA in March 2005 to reduce emissions of mercury [*43*]. On February 8, 2008, the U.S. Court of Appeals found CAMR to be unlawful and voided it, ruling that the EPA had not proved mercury to be a pollutant eligible for regulation under a less stringent portion of the Clean Air Act. Because the court's ruling came too late for EIA to remove the CAMR provisions from its analysis, *AEO2008* includes consideration of CAMR. Regardless of CAMR, however, some States have implemented plans calling for mandatory 90-percent cuts in mercury emissions from all plants of a certain size. More stringent modeling of mercury emissions limits in some regions may be necessary when State actions have been finalized.

State Greenhouse Gas Initiatives

RGGI. Since the end of 2006, three additional States have joined the Regional Greenhouse Gas Initiative (RGGI) [*44*]. Currently, RGGI includes 10 members: Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Maryland.

Although *AEO2008* does not include RGGI, given the current uncertainty about the program's structure and allowance trading, several States are now moving forward with their draft implementation plans. Massachusetts, Maine, and New York have released public drafts for comment. Each of those plans closely follows the model rules published in August 2006, requiring that 100 percent of the allowances be auctioned. It is thought that all RGGI States are likely to follow the same precedent, with a limited number of giveaway credits. RGGI formally begins in January 2009. Some States will have to enact legislation to make the program legally binding, whereas others have State agencies that already have such authority and do not need to pass new laws. As of late 2007, Vermont was the only RGGI State that had enacted a new law.

WCI. In February 2007, the governors of Arizona, California, New Mexico, Oregon, and Washington established the Western Climate Initiative (WCI). Utah and the Canadian provinces of British Columbia and Manitoba have since joined as full partners. Six additional U.S. States and several Canadian provinces participate as observers. The eight full partners have agreed to the goal of decreasing emissions to 15 percent below 2005 levels by 2020, but little else about the program has been decided. Although the WCI is leaning heavily toward a cap-and-trade system, the specifics of covered emissions, State allowance allocations and trading, emissions accounting, and offsets—among other items—still are being negotiated. *AEO2008* does not include the WCI, because it remains to be seen how the program will function and what the penalties for noncompliance will be.

WCI has a task force that will assemble a program model rule by August 2008. Some WCI partner States already have GHG laws or goals, while others, such as Utah, do not. The agreement does not override the binding GHG laws in California, Oregon, and Washington, but it does require WCI partners to join the Climate Registry, which is a collaboration of 39 U.S. States, Canadian provinces, and Mexican states seeking uniform GHG accounting and reporting.

California. California's S.B. 1368 [*45*] makes it illegal to enter into new long-term contracts to serve the State's electricity demand with power plants that produce GHG emissions in excess of 1,100 pounds per megawatthour of electricity generated—effectively prohibiting the construction of new coal-fired facilities without carbon sequestration, even if they are located in a neighboring State. *AEO2008* includes the impact of S.B. 1368 through limits on coal-fired electricity generation serving California.

California's Assembly Bill (A.B.) 1493, which would establish GHG emissions standards for LDVs, is not considered in the *AEO2008* reference case. A.B. 1493 was signed into law in July 2002, and regulations were released by the California Air Resources Board in August 2004 and approved by California's Office of Administrative Law in September 2005 [*46*]. The emission standards would be applied to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond [*47*]. The standards, specified in terms of CO_2-equivalent emissions, would apply to vehicles in two size classes: passenger cars and light-duty trucks with a loaded vehicle weight rating of 3,750 pounds or less; and light-duty trucks with a loaded vehicle weight rating greater than 3,750 pounds and a gross vehicle weight rating less than 8,500 pounds. The

CO_2-equivalent emissions standard for light trucks would include noncommercial passenger trucks between 8,500 pounds and 10,000 pounds. The regulations were to become effective in January 2006 and set near-term emission standards that were to be phased in between 2009 and 2012. The mid-term emission standards were to be phased in between 2013 and 2016. After 2016, the emissions standards would be left unchanged.

Before California can implement the GHG emission standards for vehicles established in A.B. 1493, it must receive a waiver from the U.S. EPA. The EPA, however, has denied California a waiver to regulate GHG emissions from mobile source under the Clean Air Act. Expressing concern about the establishment of regional emissions standards for new motor vehicles, the EPA reasoned that the effects of climate change in California did not support the need for a regional standard.

In October 2003, California, 11 other States, 3 cities, and several environmental groups filed a petition in the U.S. Court of Appeals, arguing that the EPA should regulate GHG emissions from vehicles. In July 2005, a three-judge panel ruled 2 to 1 in the EPA's favor, stating that the agency was not required to regulate GHGs under the Clean Air Act. The decision was overturned in April 2007 by the U.S. Supreme Court, which ruled that the EPA has authority under Section 202 of the Clean Air Act to regulate GHG emissions from automobiles. Nonetheless, on December 19, 2007, the EPA again denied California's request for a waiver [*48*]. On January 2, 2008, California and 15 other States sued the EPA, challenging its decision to deny the wavier [*49*].

AEO2008 also does not include consideration of California A.B. 32, which mandates a 25-percent reduction in California's GHG emissions by 2020. Implementing regulations have not been drafted and are not due to be finalized until January 2012.

Washington and Oregon. Washington and Oregon have joined California in the enactment of State GHG legislation. In May 2007, Washington's Governor Christine Gregoire signed S.B. 6001 [*50*], which mandates cuts in emissions and performance standards for power plants. The legislation targets reductions to 1990 emissions levels in the State by 2020, to 25 percent below the 1990 levels by 2035, and to 50 percent below the 1990 levels by 2050. Washington has not yet mandated the program specifics, such as the type of system that will be used to meet the targets. Additional action from the governor, the utilities, and the State's transportation commission will be required.

Washington State has also adopted the same standards included in California S.B. 1368. Oregon, which has CO_2 regulations for natural-gas-fired plants but not for other fossil-fuel-based power systems, passed its GHG reduction law in August 2007. The law has the same 2020 reduction goal as Washington's and also requires that emissions growth be capped by 2010. It establishes the Oregon Global Warming Commission, a body will have 25 members with various backgrounds who will serve as an advisory board to State and local governments. Like Washington and California, Oregon has not determined the specific procedures to be followed in implementing the required emissions reductions.

Other States. Many other States have goals and other provisions for GHG reductions and accounting of emissions from stationary sources. In May 2007, Montana's Governor Brian Schweitzer signed House Bill 25 [*51*], which requires any new coal-fired generating facility to sequester at least 50 percent of the CO_2 it emits. Florida's Governor Charlie Crist signed three executive orders [*52*] over the summer concerning his State's emissions of heat-trapping gases, including an overall State goal to bring emissions to 80 percent below 1990 levels by 2050. An Energy and Climate Change Action Plan will be developed to determine how the State of Florida can reach those reduction goals.

ICAP. Ten U.S. States, all of which are participants in either RGGI or WCI, have entered the International Carbon Action Partnership (ICAP). ICAP, created in October 2007, seeks collaboration among carbon trading programs. Members include nine European Union countries, the European Commission, Norway, and New Zealand. Several other U.S. States have non-binding goals, carbon registry requirements, or energy plans that include recommendations to limit CO_2 emissions from stationary sources, including those described above.

Issues in Focus

Introduction

Each year, this section of the *AEO* provides in-depth discussions on topics of special interest that may affect annual projections, including significant changes in assumptions and recent developments in technologies for energy production, supply, and consumption. In view of recent increases in construction costs, including the costs of constructing power plants, refineries, and other energy-related facilities, this year's topics include a discussion of cost trends and the implications for energy markets. Other issues discussed this year include the implications of increased reliance on natural gas in the electricity generation sector, warming weather trends and their effects on energy demand, LNG imports, and world oil prices and production trends.

The topics explored in this section represent current, emerging issues in energy markets; but many of the topics discussed in *AEO*s published in recent years are relevant today. Table 5 provides a list of titles from the 2005, 2006, and 2007 *AEO*s that are likely to be of interest to today's readers. They can be found on EIA's web site at www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_analyses. html.

Impacts of Uncertainty in Energy Project Costs

From the late 1970s through 2002, steel, cement, and concrete prices followed a general downward trend. Since then, however, iron and steel prices have increased by 8 percent in 2003, 10 percent in 2004, and 31 percent in 2005. Although iron and steel prices declined in 2006, early data for 2007 show another increase. Cement and concrete prices, as well as the composite cost index for all construction commodities, have shown similar trends but with smaller increases in 2004 and 2005 (Figure 9).

Recent increases in the costs of basic commodities and increases in capital costs for energy equipment and facilities could have significant effects on future energy supplies and consumption. Higher capital costs could change both the competition among fuels and technologies and the marginal costs of new energy supplies. In the electric power sector, for example, capital costs are generally lower for generating plants that use fossil fuels than for plants that use nuclear or renewable fuels. If capital costs increased on a proportional basis for plants of all types, then capital-intensive nuclear and renewable power plants would become even less competitive with fossil-fired plants when new capacity is planned. In addition, over the long term, higher capital costs would lead to

Figure 9. Changes in construction commodity costs, 1973-2007 (constant dollar index, 1973=100; 1981=100 for cement costs)

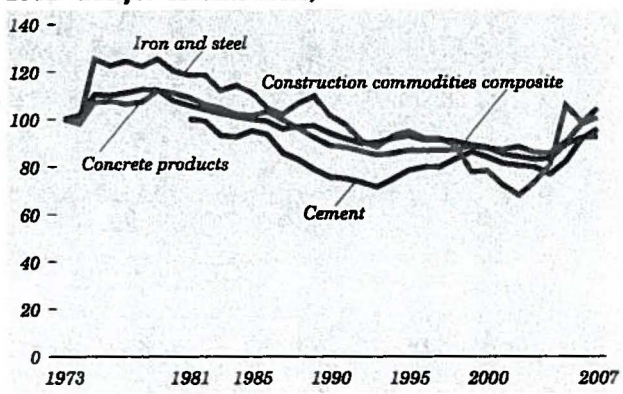


Table 5. Key analyses from "Issues in Focus" in recent AEOs

AEO2007	AEO2006	AEO2005
Impacts of Rising Construction and Equipment Costs on Energy Industries	*Economic Effects of High Oil Prices*	*Changing Trends in the Bulk Chemicals and Pulp and Paper Industries*
Energy Demand: Limits on the Response to Higher Energy Prices in the End-Use Sectors	*Changing Trends in the Refining Industry*	*Fuel Economy of the Light-Duty Vehicle Fleet*
Miscellaneous Electricity Services in the Buildings Sector	*Energy Technologies on the Horizon*	*Production Tax Credit for Renewable Electricity Generation*
Industrial Sector Energy Demand: Revisions for Non-Energy-Intensive Manufacturing	*Advanced Technologies for Light-Duty Vehicles*	*Distributed Generation in Buildings*
Impacts of Increased Access to Oil and Natural Gas Resources in the Lower 48 Federal Outer Continental Shelf	*Nonconventional Liquid Fuels*	*Restricted Natural Gas Supply Case*
Alaska Natural Gas Pipeline Developments	*Mercury Emissions Control Technologies*	
Coal Transportation Issues	*U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative*	

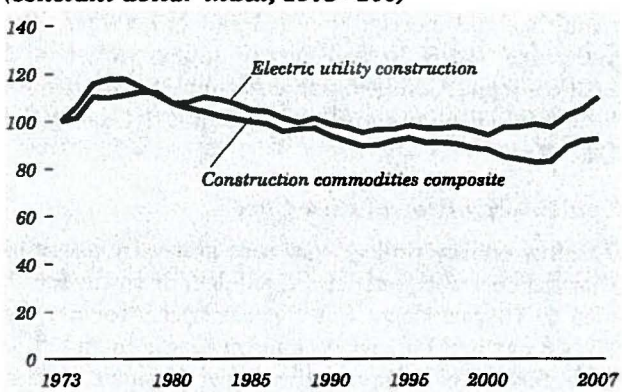
higher energy prices, which in turn could slow the growth of energy consumption.

The *AEO2008* version of NEMS includes updated assumptions about the costs of new power plants, the costs of drilling and pipeline construction in the oil and natural gas industry, refinery costs, and capital costs in the LNG supply chain. In the reference case, energy project costs are assumed to level off over the long term. To examine the effects of different assumptions about future costs, high and low energy project cost cases were developed, assuming higher and lower costs than in the reference case.

Power Plant Construction

In the electric power industry, cost estimates for individual construction projects to be completed over the next decade have increased by 50 percent or more in recent years [*53*]. Increased costs have been reported for power plants of all types, including coal, nuclear, natural gas, and wind. The Handy-Whitman index for electric utility construction (which is used as a proxy for all electric power industry projects) provides an average cost index for six regions in the United States, starting from 1973. A simple average of the regions is used in Figure 10 to show the national trend for power plant construction relative to the cost index for construction materials. The two indexes diverge in the early 2000s, when power plant construction costs began to show a flat to slightly increasing trend, while general construction costs continued to decline. With the sharpest increases in electric utility construction costs occurring over the past 3 years, the electric utility construction cost index for 2007 is 17 percent higher than its low point in 2000.

Figure 10. Changes in construction commodity costs and electric utility construction costs, 1973-2007 (constant dollar index, 1973=100)



Oil and Natural Gas Industry

Exploration and Production

According to the American Petroleum Institute's *Joint Association Survey of Drilling Costs* (JAS), the average real cost of drilling an onshore well almost doubled in 2004 and increased by another 10 percent in 2005. The increases are attributable in part to the increased drilling activity brought on by higher prices for crude oil and natural gas; however, there is a great deal of uncertainty as to whether the recent escalation in drilling costs represents a fundamental shift in the drilling services industry or is a temporary aberration that will be corrected in the near term.

Natural Gas Pipelines

Historical trends in pipeline construction costs are more difficult to identify, because the cost data are not readily available; however, average real capital costs for lower 48 pipeline construction appear to have increased by some 70 percent over the past 3 years. Anecdotal evidence suggests that new estimates for the cost of constructing an Alaska pipeline are 50 percent higher than the estimates published in May 2002, and estimates for a Mackenzie Delta pipeline also are higher than the preliminary estimates from 2003.

LNG Facilities

Construction cost estimates for new natural gas liquefaction facilities scheduled to come on line between 2008 and 2011 increased by 50 percent in 2006 relative to those reported a year earlier for the same period. Some of the increase may be due to strong growth in demand for LNG liquefaction capacity. This cost pressure will not persist as markets adjust and additional projects are announced and completed; however, a portion of the increase is due to increased material costs, shortage of experienced workers, and construction bottlenecks that are likely to persist or take longer to resolve. The costs for regasification facilities and receiving terminals have also increased sharply—by more than 50 percent—over the past few years. Based on contracts signed between 2000 and 2006, LNG shipping costs have also risen by more than 7 percent over the past few years.

Petroleum Refineries and Ethanol Plants

The Nelson-Farrar refinery construction cost indexes, which track overall costs for refinery construction, show a 30-percent increase from 2003 to 2005 in real dollar terms. Similarly, the Chemical Engineering

Plant Cost Index (CEPCI) shows a significant increase in ethanol plant construction costs over recent years. Because there has not been a significant increase in U.S. refining construction activity over the past few years, cost increases in the petroleum refining sector largely reflect higher prices for the various commodities used in the refining industry (steel, nickel, cobalt, etc.) rather than significant increases in demand for refinery services and equipment.

Case Descriptions

Reference Case

The *AEO2008* reference case includes updated information on the current costs of construction and investment in the energy industry, based on recent data and estimates that show higher costs than were assumed for *AEO2007*. In most of the *AEO2008* cases, the higher cost levels are assumed to continue throughout the projections. For the electric power sector, initial costs for all technologies are 15 percent higher than those in *AEO2007* and continue to be higher throughout the projection, although overnight costs fall over time as a result of technology learning.

For the oil and natural gas industry, regional drilling costs are calculated annually from econometrically derived equations, which are based on historical data from the American Petroleum Institute's JAS, and estimates of the number of wells being drilled and the average depth of each well. The cost increases seen after 2003 are represented by an explicit multiplier that captures the combined impacts of various cost factors other than drilling activity and well depth. In the reference case, the cost escalation factor is applied and held constant over the projection, but its effect is partially offset by an annual technology improvement factor that reflects learning and increased efficiency.

Pipeline construction costs are based on average construction cost data filed between 1992 and 2008, and they are assumed to remain constant through 2030. The reference case also assumes that the recent, higher estimates for an Alaska pipeline and a pipeline from the Mackenzie Delta remain constant through 2030.

Construction costs for new natural gas liquefaction facilities were increased by 50 percent in *AEO2008* to match the 2006 cost estimate for facilities scheduled for completion between 2008 and 2011. The construction costs are assumed to remain constant at that level through 2015, then decline to only 15 percent above their pre-2006 levels in 2018 as the market adjusts, after which the costs are assumed to remain constant at the 2018 level through 2030. LNG shipping costs and construction costs for regasification facilities are assumed to be 15 percent and 7 percent higher, respectively, than their 2006 level throughout the *AEO2008* projection.

Construction costs for refineries and for ethanol production plants are assumed to remain constant at 2006 levels through 2030, based on the Nelson-Farr index and CEPCI, respectively.

High Energy Project Cost Case

The high energy project cost case assumes that the cost of construction will continue to rise. For electricity generation plants, the base capital cost for all technologies rises at a rate of 2.5 percent per year—similar to the average increase over the past 3 years—through 2030, offset in part by learning effects.

For the oil and natural gas industry, the escalation factor for drilling costs is assumed to increase to twice its original value by 2010 and remain constant thereafter. It is offset in part by an annual technology improvement factor. Pipeline construction costs are assumed to start at the reference case level but grow to about 25 percent above the reference case level in 2030.

LNG liquefaction costs match the reference case increase through 2008 and add an additional 20 percent thereafter. Construction costs for LNG regasification facilities are 15 percent above the reference case level in 2008 and then held constant through 2030. LNG shipping costs are increased to 7 percent above the reference case level in 2008 and then held constant through 2030.

For the refining sector, construction costs are increased above the reference case level by a factor equal to the percentage difference between the 2004 and 2006 Nelson-Farrar index values and held constant. Construction costs for corn and cellulosic ethanol plants are treated similarly, using the CEPCI.

Low Energy Project Cost Case

The low energy project cost case generally assumes that the cost of construction will decline to the levels of 5 to 10 years ago. For the electricity sector, the 15-percent capital cost escalation factor included in the reference case is phased out over 10 years, so that

overnight construction costs for all generating technologies are 15 percent lower than those in the reference case by 2017.

For the oil and natural gas industry, the drilling cost escalation factor applied in the reference case is phased out by 2010. Pipeline construction costs start at the reference case level but decline gradually to about 25 percent below the reference case level in 2030. For LNG liquefaction facilities, construction costs are reduced gradually from those in the reference case, returning to 2006 levels by 2015 and remaining constant thereafter. Similarly, construction costs for LNG regasification facilities and costs for LNG shipping costs decline gradually from reference case levels, return to 2006 levels by 2018, and remain constant thereafter. Refinery construction costs are assumed to return to 2004 levels by 2008 and then remain constant through 2030.

Results

Electricity: Capacity Additions and Generation

The projected mix of generating capacity types added in the electric power sector from 2006 to 2030 does not vary significantly among the reference, high energy project cost, and low energy project cost cases, because increases or decreases in construction costs have similar impacts on new builds for all technology types on a percentage basis. For example, coal-fired technologies provide about 40 percent of all new capacity additions in each of the three cases. More capital-intensive technologies, including nuclear and renewables, are affected somewhat more, however, than those with lower capital costs, including natural-gas- and coal-fired plants.

In the high energy project cost case, coal-fired capacity additions are reduced by 13 gigawatts from the reference case level, but with higher costs leading to higher electricity prices and lower demand, less new generating capacity is needed overall. As a result, the coal share of new builds remains almost the same as in the reference case. The technology most affected is nuclear power: no new nuclear capacity is built before 2030 in the high energy project cost case (Figure 11). Renewable capacity additions are 17 percent lower than in the reference case, but total generation from renewable plants is about the same in order to meet the requirements of State and regional RPS programs. The increase in renewable generation comes primarily from biomass co-firing at existing coal plants.

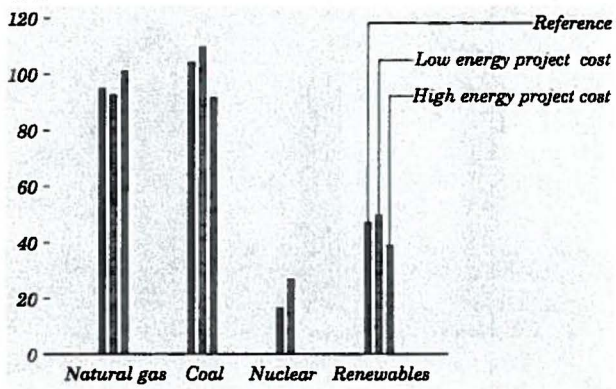
Because they are the least expensive to build, natural gas capacity additions increase in the high energy project cost case relative to the reference case, meeting 43 percent of new capacity needs. As a result, natural-gas-fired generation in 2030 is 22 percent higher than in the reference case. Average electricity prices in 2030 are 9 percent higher in the high energy project cost case than in the reference case.

In the low energy project cost case, more capacity of all types except natural gas is added over the projection period. The largest increase is in nuclear capacity additions, which are 10 gigawatts higher than in the reference case. Because capital costs make up a smaller share of total costs for natural-gas-fired capacity additions than for other technologies, they are slightly less economical in the low energy project cost case and about 3 gigawatts lower than in the reference case. The fuel shares of total generation in 2030 are similar in the low energy project cost case and the reference case, with a small decrease in the natural gas share (to 13 percent, compared with 14 percent in the reference case). The nuclear share of total generation increases from 18 percent in the reference case to 19 percent in the low energy project cost case. Electricity prices in 2030 are 4 percent lower in the low energy project cost case than in the reference case.

Natural Gas: Supply, Consumption, and Prices

Natural gas supply volumes are determined primarily by consumption levels, particularly for electric power generation. Capital costs play a role in determining the relative shares of total supply derived from conventional, unconventional, LNG imports, and other supply categories.

Figure 11. Additions to U.S. electricity generation capacity by fuel in three cases, 2006-2030 (gigawatts)



Total domestic natural gas production in 2030 differs by 1.6 trillion cubic feet between the low and high energy project cost cases (Figure 12). Lower 48 onshore production differs by 1.1 trillion cubic feet between the two cases, with conventional and unconventional production accounting for 0.6 and 0.5 trillion cubic feet of the total difference. Production from Alaska and offshore production differ by 0.4 and 0.2 trillion cubic feet, respectively, between the low and high energy project cost cases.

In 2030, total net natural gas imports are 3.1 trillion cubic feet in the high energy project cost case and 3.4 trillion cubic feet in the low energy project cost case. LNG imports account for more than 80 percent of total net natural gas imports in all the cases, and the capital costs for LNG facilities are by far the largest component of LNG supply costs. Net LNG imports are 2.5 trillion cubic feet in 2030 in the high energy project cost case, compared with 2.8 trillion cubic feet in the low energy project cost case.

The picture for net pipeline imports of natural gas from Canada and Mexico is more complex. In the reference case, because recent cost estimates indicate that a Mackenzie Delta pipeline would not be economical to build [*54*], net pipeline imports total only 0.3 trillion cubic feet in 2030. In the low energy project cost case, a Mackenzie pipeline would begin operation in 2014, providing about 420 billion cubic feet per year through 2030; as a result, net pipeline imports to the United States total 0.5 trillion cubic feet in 2030. In the high energy project cost case, with higher U.S. prices for natural gas inducing more production and exports from Canada, net U.S. pipeline imports total 0.6 trillion cubic feet in 2030.

Differences in total natural gas consumption in the energy project cost cases are determined primarily by the different amounts used for electricity generation. Because coal, nuclear, and renewables are more competitive with natural gas in the low energy project cost case and capture a larger share of new capacity additions, natural gas consumption in the electric power sector in 2030 is 0.4 trillion cubic feet lower than the reference case projection of 5.0 trillion cubic feet (Figure 13).

As a result of the lower level of natural gas use for electricity generation in the low energy project cost case, total domestic natural gas consumption and prices in 2030 are lower than in the reference case: consumption by 0.3 trillion cubic feet (from 22.7 trillion cubic feet in the reference case) and wellhead gas prices by $0.33 (2006 dollars) per thousand cubic feet (from $6.63 in the reference case) (Figure 14).

In the high energy project cost case, new natural-gas-fired electricity generation capacity is considerably less expensive than competing technologies, and the natural gas share of capacity additions increases, resulting in higher total consumption and prices for

Figure 12. U.S. natural gas supply by source in three cases, 2030 (trillion cubic feet)

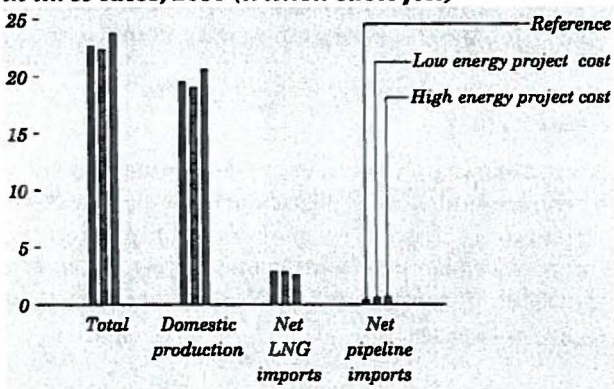


Figure 13. U.S. natural gas consumption by sector in three cases, 2030 (trillion cubic feet)

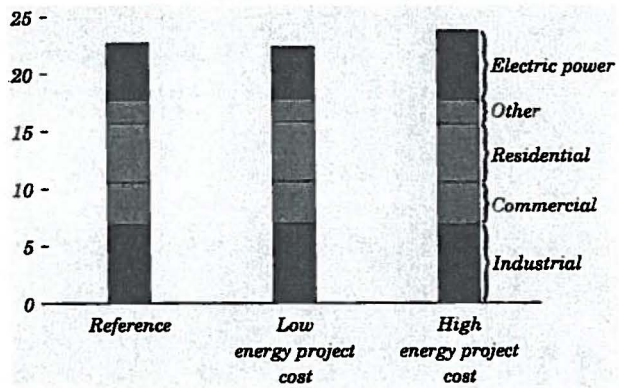
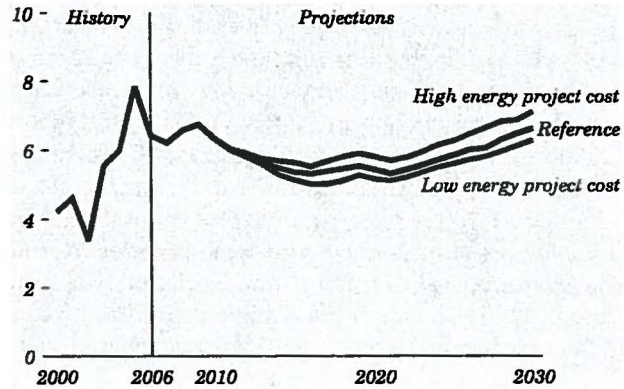


Figure 14. U.S. natural gas prices in three cases, 2000-2030 (2006 dollars per thousand cubic feet)



natural gas than in the reference case. The increase in consumption for electricity generation leads to higher total domestic consumption (by 1.1 trillion cubic feet) and higher price levels (by $0.49 per thousand cubic feet) for natural gas than in the reference case. Because of the higher prices, natural gas consumption in the residential, commercial, and industrial sectors in 2030 is lower than projected in the reference case.

Petroleum Liquids Supply

A large part of the domestic oil resource base has been produced, and new oil reservoir discoveries are expected to be smaller, more remote (offshore deepwater, for example), and more costly to exploit. With a few exceptions—namely, deepwater Gulf of Mexico and offshore Alaska—the remaining domestic petroleum basins have been significantly depleted. Consequently, EOR using miscible CO_2 is the primary extraction technique expected to keep onshore oil production at a relatively high level through 2030. The assumptions in the low and high energy project cost cases were applied only to the domestic resource. Depletion of domestic oil resources constrains the high and low energy project cost assumptions from having a significant impact on domestic oil production. The low and high energy project cost cases would show larger impacts if the assumptions were applied to world liquid supplies.

A slow, continuous decline in oil production is projected for the onshore United States, even with the relatively high oil prices [*55*]. Future domestic onshore oil production is dominated by large oil fields that were discovered decades ago, and EOR only extends their productive life. For example, although the Prudhoe Bay Field started production in 1976, the largest share of Alaska's oil production still comes from Prudhoe Bay. Although large oil fields on Alaska's North Slope came into production more recently [*56*], the long-term trend is for Alaska's oil production to decline as the Prudhoe Bay Field declines. The *AEO2008* reference case and low and high energy project cost cases include constant or declining U.S. oil production, as smaller and smaller new fields come into production while the larger existing fields continue to be depleted [*57*].

In the low energy project cost case, total domestic oil production in 2030 is 18,000 barrels per day higher than projected in the reference case. In the high energy project cost case, higher drilling costs reduce both the rates of return on oil production and the cash flow of oil producers, and as a result total domestic production in 2030 is about 300,000 barrels per day lower than in the reference case.

Because EOR is highly capital-intensive, most of the variation in domestic oil production across the three cases reflects differences in EOR production. In the reference case, CO_2 EOR production in 2030 totals 1.31 million barrels per day, as compared with 1.33 million barrels per day in the low energy project cost case and 980,000 barrels per day in the high energy project cost case.

For deepwater production in the Gulf of Mexico, the reference case projects an increase from about 970,000 barrels per day in 2006 to 2.0 million barrels per day from 2013 through 2019, followed by a decline to 1.6 million barrels per day in 2030. The projections in the low energy project cost case are nearly the same, because the constraints on deepwater development are not prices and costs but long development lead times and limited infrastructure. In the high energy project cost case, the capital intensity of deepwater development constrains oil production in the Gulf in the earlier years, with a peak production level of 1.9 million barrels per day from 2013 through 2019. As oil prices increase later in the projection period, however, small deepwater fields that were uneconomical in earlier years begin to be developed. In 2030, deepwater production in the Gulf is about 30,000 barrels per day higher in the high energy project cost case than projected in the reference case [*58*].

Both CTL and BTL production are also capital-intensive and vary significantly on a percentage basis across the three cases. Combined production from CTL and BTL facilities is about 620,000 barrels per day in 2030 in the low energy project cost case, compared with 510,000 barrels per day in the high energy project cost case.

The only other petroleum supply category significantly affected in the energy project cost cases is natural gas liquids (NGL). In the high energy project cost case, which projects considerably more natural gas production than the low case, NGL production is also higher, at 1.6 million barrels per day, compared with 1.5 million barrels per day in the low case. As a result, the difference in combined CTL and BTL production between two cases is almost completely offset by the difference in NGL production.

Crude oil prices are not projected to vary significantly across the three cases. The reference case projects a

price of $70.45 per barrel for low-sulfur light crude oil in 2030 (2006 dollars), compared with $70.33 per barrel in the low energy project cost case and $70.65 per barrel in the high energy project cost case. Accordingly, total domestic consumption of petroleum liquids does not vary by much, at 22.7 million barrels per day in the high energy project cost case and 22.8 million barrels per day in the low energy project cost case. Imports of crude oil and liquid fuels make up the difference between the projections for liquids production and consumption in each case, varying from 55.5 percent of total U.S. supply in 2030 in the high energy project cost case to 54.0 percent in the low energy project cost case. As noted above, the impacts would be more significant if the assumptions in the low and high energy project cost cases were applied to global markets.

Limited Electricity Generation Supply and Limited Natural Gas Supply Cases

Development of U.S. energy resources and the permitting and construction of large energy facilities have become increasingly difficult over the past 20 years, and they could become even more difficult in the future. Growing public concern about global warming and CO_2 emissions also casts doubt on future consumption of fossil fuels—particularly coal, which releases the largest amount of CO_2 per unit of energy produced. Even without regulations to limit greenhouse gas emissions in the United States, the investment community may already be limiting the future use of some energy options. In addition, there is considerable uncertainty about the future availability of, and access to, both domestic and foreign natural gas resources.

To examine the effects of uncertainty about future supplies of electricity and natural gas, three alternative cases were developed for *AEO2008*. The limited electricity generation supply case assumes that higher construction and operating costs together with other factors, such as lack of public acceptance, will limit the use of energy sources other than natural gas for power generation—including coal without CCS technology, nuclear power, and renewable fuels. The limited natural gas supply case assumes that no Arctic natural gas pipeline will be in operation before 2030, the availability of LNG to U.S. regasification terminals will be limited, the U.S. oil and natural gas resource base will be less than in the reference case, access to the resource base will be more limited than assumed in the reference case, and that improvements in oil and natural gas exploration and development technologies will be slower than in the reference case. Finally, a combined limited case includes all the assumptions from the first two cases.

Assumptions

Limited Electricity Generation Supply Case

In the *AEO2008* reference case, based on existing laws and regulations, the use of natural gas for electricity generation continues to increase in the near term, then declines as generators increasingly turn to coal, renewables, and new nuclear power capacity in the longer term. New coal-fired capacity without CCS could be limited, however, by policy changes aimed at limiting CO_2 emissions. Several States already are beginning to implement emission reduction programs, and the U.S. Congress is discussing potential Federal programs. In California and Washington State, recent legislation has set emission standards for electric power plants that would preclude new coal-fired plants without CCS from providing power to those States (see "Legislation and Regulations"). There are also several proposals at the Federal level that would impose caps on CO_2 emissions. The limited electricity generation supply case, in addition to assuming that new coal-fired power plants without CCS cannot be built, also assumes that construction costs for new plants with CCS will be 25 percent higher than in the reference case.

Currently, new nuclear capacity is being proposed in response to incentives provided in EPACT2005, rising fossil fuel prices, and concerns about CO_2 emissions; however, there continue to be concerns about nuclear waste disposal, public acceptance, and the ability to build new plants on time and within budget. It is likely that some new nuclear plants will be built, given current interest levels and financial incentives, but if early builds encounter delays in construction or licensing or significant cost overruns (as occurred with the first generation of nuclear plants), the long-term potential for nuclear electricity in the United States could be reduced.

The limited electricity generation supply case assumes the same amount of new nuclear capacity as in the reference case by 2030; however, in circumstances where the reference case assumes that current capacity factors, averaging over 90 percent nationally, will be maintained throughout each plant's 60-year lifetime, the limited electricity generation supply case assumes that the national average

capacity factor for nuclear power plants will fall to 70 percent in 2030. To date, no nuclear power plant has operated for 40 years, and industry experience in maintaining older nuclear plants is limited. Thus, it is possible that replacement of major components on older plants could cause significant outages, or that gradual breakdowns could lead to lower capacity factors.

Adding large amounts of economical renewable capacity may also face challenges. The reference case projects a large increase in renewable capacity (mostly wind and biomass), mainly to meet the requirements of State RPS programs. There is also some public resistance to the siting of new wind and biomass plants, however, and their costs may increase after the "best" sites have been used. The limited electricity generation supply case assumes the same amounts of new wind and biomass capacity as in the reference case, but the availability of new biomass energy crops is delayed until 2020, compared with 2010 in the reference case. Biomass gasification technology is a new, unproven design that could run into delays and cost overruns, and in addition it could take many years to develop the infrastructure to grow, cultivate, harvest, and transport new energy crops. The costs for all other new renewable capacity (geothermal, landfill gas, solar thermal, and solar PV) are assumed to be 25 percent higher than in the reference case. Again, these technologies are new, and there is considerable uncertainty about initial cost estimates.

Limited Natural Gas Supply Case

The limited natural gas supply case represents an environment in which numerous natural gas supply options are unavailable, less available, or more costly to develop than in the reference case.

Among the most significant uncertainties for future natural gas supply are the development of natural gas pipelines in the Arctic region of North America, the future availability of LNG imports, the size of the domestic natural gas resource base, and the rate of technological improvement in the industry. Currently, two large natural gas pipelines are under consideration for development in the Arctic region: a Mackenzie Delta pipeline in Canada and an Alaska pipeline [*59*], both of which are large, expensive construction projects. It is expected that 6 years will be required to permit, license, design, construct, and open the Mackenzie pipeline and 9 years will be required to do the same for the Alaska pipeline. A number of factors could delay completion of the projects beyond 2030, however, including: higher-than-expected construction costs that would make the pipelines unprofitable throughout the projection period; higher-than-expected State and Provincial taxes and royalties on natural gas production; environmental concerns requiring expensive remediation; delays in regulatory approval and permitting; and difficulties in addressing the concerns of native peoples whose lands are crossed by the pipelines. Accordingly, the limited natural gas supply case assumes that neither pipeline will be opened before 2030.

The future availability of LNG imports depends critically on the development of new LNG supply sources throughout the world, which in turn will require the construction of large, expensive liquefaction facilities and LNG tankers. Typically their financing is supported by multi-decade contract commitments from large natural gas consumers, such as natural gas and electric utilities; however, those large consumers face considerable uncertainty of their own, including whether new nuclear generating capacity will reduce long-term requirements for natural gas supply, whether alternative supplies will be available from other sources at lower prices, and whether suitable pricing mechanisms will be available to ensure that LNG suppliers earn a reasonable rate of return while the consumers pay prices that are reasonable in comparison with the prices of other sources of natural gas supply.

It is possible that potential LNG suppliers could face considerable difficulty in obtaining customer commitments sufficient to support the financing required for development of LNG supplies that are able to satisfy world demand for natural gas. Further, if LNG supplies are scarce relative to world demand, overseas natural gas prices could exceed U.S. domestic prices, drawing LNG supplies away from the U.S. market. Alternatively, new sources of LNG supply could be fully committed to overseas customers under long-term contracts, making spot purchases of LNG either unavailable or prohibitively expensive.

Availability of supplies could also be limited by policies adopted by the countries that produce LNG. For example, LNG producers could operate in concert to limit LNG supplies in order to increase prices or to make more natural gas available to their own consumers. They might also adopt production taxes,

excise taxes, and tariffs that would make LNG economically unattractive in the United States.

The LNG assumptions used in the limited natural gas supply case are identical to those used in the low LNG case (discussed later in "Issues in Focus"), with U.S. gross imports of LNG held constant at 1.0 trillion cubic feet per year from 2009 through 2030 [*60*]. The LNG restrictions apply to the United States only; LNG imports to Canada and Mexico remain sensitive to prices, and new LNG import capacity is assumed to be constructed in those countries according to predetermined price triggers.

The actual size of the domestic oil and natural gas resource base is another source of uncertainty. The USGS and Minerals Management Service (MMS) calculate the U.S. undiscovered oil and natural gas resource base on a probabilistic basis, reporting a mean estimate, a 95-percent probability estimate, and a 5-percent probability estimate of technically recoverable oil and natural gas resources in each major U.S. petroleum basin. As an example, for the U.S. lower 48 onshore basins, the USGS mean probability estimate of undiscovered natural gas resources is 483 trillion cubic feet, the 95-percent probability estimate is 291 trillion cubic feet, and the 5-percent probability estimate is 735 trillion cubic feet [*61*], illustrating the wide range of uncertainty with regard to the size of the U.S. oil and natural gas resource base.

The *AEO2008* reference case assumes that the technically recoverable U.S. oil and natural gas resource base is equal to the USGS and MMS mean estimates. Given the uncertainty inherent in those estimates, however, the actual resource base could be considerably smaller. Further, the ability to develop the resource base could be limited by other factors, including the possibility that future laws and regulations could place more Federal and State land off limits to oil and natural gas production. The limited natural gas supply case assumes that the U.S. unproven oil and natural gas resource base and Canada's undiscovered natural gas resource base are 15 percent smaller than the estimates used in the reference case.

Another factor that could reduce available natural gas supplies is a slowdown in the rate of technological progress. Technological progress generally reduces the cost of finding, developing, and producing natural gas resources. In addition to their direct impacts on costs, technology improvements can increase finding and success rates, which have an impact on the average costs of production. A slower rate of progress results in higher capital and operating costs for oil and natural gas exploration and development than would otherwise be the case. The limited natural gas supply case assumes a technological progress rate that is one-half the rate in the reference case.

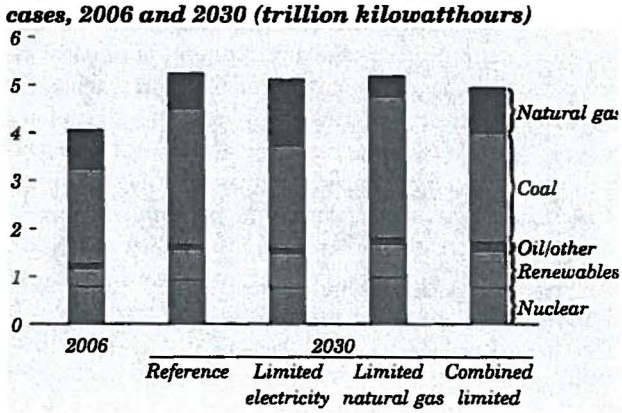
Results

Electricity Generation

In 2006, coal-fired power plants supplied 49 percent of U.S. electricity generation. In the *AEO2008* reference case, coal's market share is maintained through 2020 and grows to 54 percent in 2030, primarily as a result of projected increases in natural gas prices. In the limited electricity generation supply case, natural gas supplies are unchanged from those in the reference case, while generation from other fuels is constrained. As a result, the coal share of total generation drops to 42 percent in 2030, and the natural gas share increases from 20 percent in 2006 to 27 percent in 2030, as compared with 14 percent in 2030 in the reference case (Figure 15). By assumption, nuclear, wind, and biomass remain at or below reference case levels from 2006 through 2030, while generation from other renewables and from oil increases slightly. Although delivered natural gas prices to the electric power sector in 2030 are 16 percent higher in the limited electricity generation supply case than in the reference case because of higher demand, the price increase is not enough to shift generation from natural gas to the competing technologies.

In the limited natural gas supply case, no constraints are assumed for any electricity generation technology relative to the reference case, but natural gas supplies

Figure 15. Electricity generation by fuel in four cases, 2006 and 2030 (trillion kilowatthours)



In the limited natural gas supply case, where total natural gas consumption in 2030 is 3.8 trillion cubic feet less than in the reference case, the lack of an Alaska pipeline and the constraint on U.S. LNG imports account for 2.9 trillion cubic feet of the reduction in natural gas supply. Unconventional natural gas production is also reduced by 1.8 trillion cubic feet, whereas domestic production from other sources, particularly onshore conventional resources, is increased by 0.4 trillion cubic feet and pipeline imports are increased by 0.6 trillion cubic feet.

The decrease in unconventional natural gas production in the limited natural gas supply case relative to the reference case is a direct result of the changes in supply assumptions. Because the undiscovered unconventional resource base is considerably larger than the conventional resource base, the assumption of a 15-percent smaller resource base has the greatest volumetric impact on unconventional natural gas resources. Technology advances already have made most conventional supplies economically recoverable, and thus a reduced rate of technological progress has a larger impact on the cost of developing unconventional and offshore resources. Deepwater offshore resources are further constrained by infrastructure limitations and long lead times for the construction of new production platforms and pipelines. Thus, conventional production increases, unconventional production decreases, and there is only a small increase in offshore production in the limited natural gas supply case relative to the reference case.

Although the natural gas technology and resource assumptions in the limited natural gas supply case apply to Canada as well as to the United States, LNG imports into Canada and Mexico are not constrained [62] and are responsive to higher prices. As a result, both countries are projected to increase their LNG imports and make more natural gas available to the U.S. market by pipeline.

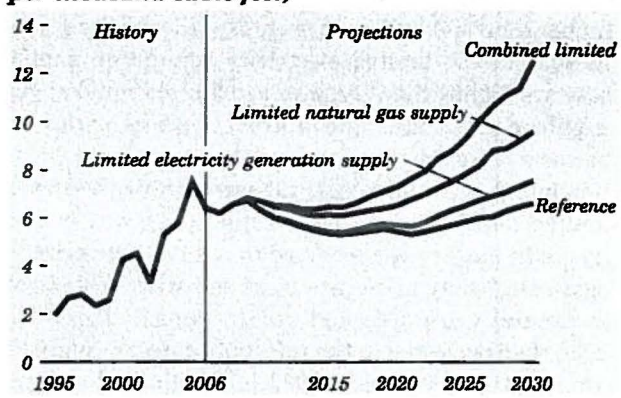
In the combined limited case, net natural gas pipeline imports in 2030 are almost 6 times the reference case level. Although U.S. pipeline imports of natural gas might be expected to increase in the limited electricity generation supply case, the assumed opening of an Alaska natural gas pipeline reduces Canadian exports to the United States.

Before 2025, the largest source of incremental U.S. natural gas supply in the combined limited case is conventional lower 48 natural gas production. In 2030, however, higher natural gas prices cause net pipeline imports to become the largest source of incremental supply. Net pipeline imports in 2030 are 1.6 trillion cubic feet higher and account for slightly more than one-half of the total increase in natural gas supply in the combined limited case relative to the reference case. LNG imports into Canada and Baja California, Mexico, are 1.1 trillion cubic feet higher in the combined limited case than in the reference case in 2030, accounting for more than 50 percent of the increase in net pipeline imports. Other domestic production accounts for the remainder of the difference in incremental supply between the two cases in 2030, with onshore conventional production 1.3 trillion cubic feet higher and offshore production 0.2 trillion cubic feet higher in the combined limited case than in the reference case. The increases in domestic conventional natural gas production and pipeline imports offset declines in unconventional production and Alaska production. They also offset a decline in LNG imports that are eliminated from the combined limited case by assumption but are available in the reference case.

Natural Gas Prices

In each of the three limited cases, natural gas prices are higher than projected in the reference case (Figure 19). The assumptions for the limited natural gas supply case have a more significant impact on price than those for the limited electricity generation supply case, with natural gas wellhead prices 45 percent and 14 percent higher in 2030 than in the reference case, respectively. The largest difference from the reference case is in the combined limited case, with prices 89 percent higher than in the reference case in 2030. End-use prices for natural gas increase in response to the higher wellhead prices and

Figure 19. Lower 48 wellhead natural gas prices in four cases, 1995-2030 (2006 dollars per thousand cubic feet)



moderate consumption, while price increases both result from and contribute to changes in the mix of supply sources.

The reason for the large price variations across the cases is the need to turn to more expensive sources of supply to satisfy the demand for natural gas as consumption increases and available sources of supply diminish. With the exception of Alaska and unconventional natural gas, the domestic conventional natural gas resource base is largely depleted, and only limited production increases are possible in response to consumption increases. Most of the large conventional fields have already been discovered, leaving only the smaller and deeper fields that are more costly to develop.

In the limited electricity generation supply case, which assumes the same resource base and rate of technological progress as in the reference case, unconventional natural gas production increases in response to higher prices. The assumptions for the limited natural gas supply case limit technological progress and reduce the size of the resource base, causing a much greater price increase than in the limited electricity generation supply case. Increased demand for natural gas in the limited electricity generation supply case raises the natural gas wellhead price in 2030 to $7.57 per thousand cubic feet, compared with $6.63 per thousand cubic feet in the reference case. In the limited natural gas supply case, the wellhead price in 2030 is $9.61 per thousand cubic feet, and in the combined limited case it is $12.55 per thousand cubic feet.

Electricity Prices

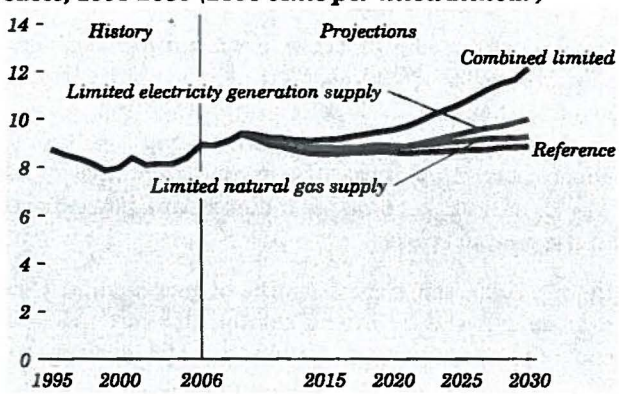
In the *AEO2008* reference case, real electricity prices are projected to remain relatively flat, with the 2030 price slightly below the current price. In the three limited cases, all with higher natural gas prices, electricity prices in 2030 are 4 percent to 36 percent higher than 2006 prices (Figure 20). Electricity prices in 2030 in the limited electricity generation supply case are higher than those in the limited natural gas supply case, even though natural gas prices are lower, because there are more options to change the generation mix in the limited natural gas supply case. In the limited electricity generation supply case, with capacity additions largely restricted to natural gas technologies, electricity prices are more sensitive to changes in natural gas prices and are 13 percent higher in 2030 than projected in the reference case. In comparison, electricity prices in 2030 in the limited natural gas supply case are 5 percent higher than in the reference case. In the combined limited case, electricity prices in 2030 are 37 percent higher than in the reference case.

Trends in Heating and Cooling Degree-Days: Implications for Energy Demand

Weather-related energy use, in the form of heating, cooling, and ventilation, accounted for more than 40 percent of all delivered energy use in residential and commercial buildings in 2006. Given the relatively large amount of energy affected by ambient temperature in the buildings sector, EIA has re-evaluated what it considers "normal" weather for purposes of projecting future energy use for heating, cooling, and ventilation. In *AEO2008*, estimates of "normal" heating and cooling degree-days are based on the population-weighted average for the 10-year period from 1997 through 2006.

In previous *AEO*s, EIA used the National Oceanic and Atmospheric Administration (NOAA) 30-year average for heating and cooling degree-days as a benchmark for normal weather. Over the past several years, however, many energy analysts have questioned the use of the 30-year average, given the recent trend toward warmer weather relative to the 30-year average. Figure 21 shows percentage differences from the 30-year average in heating and cooling degree-days for the past 15 years. Over the 15-year period, only two winters have been colder, and all but three summers have been warmer, than the 30-year average; and on average, the winters have been 4 percent warmer and the summers 5 percent warmer than the 30-year average. Five of the 15 summers were more than 10 percent warmer than the 30-year average, whereas only 2 of the 15 winters were 10 percent

Figure 20. U.S. average electricity prices in four cases, 1995-2030 (2006 cents per kilowatthour)

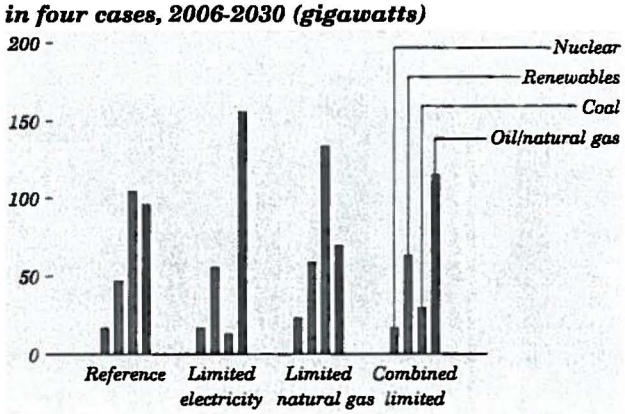


are limited. As a result, in 2030, delivered natural gas prices to the electric power sector are 39 percent higher than in the reference case, and natural-gas-fired generation is 42 percent less than in the reference case. With no technology restrictions, natural gas is displaced by increases in the use of coal, nuclear, and some renewables (geothermal, biomass, and wind) for electricity generation.

In the combined limited case, all the fuel choices for electricity generation are more expensive than in the reference case. Natural-gas-fired generation in 2030 is higher than in the reference case, but with higher natural gas prices (84 percent higher than those in the reference case) the difference is smaller than in the limited electricity generation supply case. Coal-fired plants with CCS are built, increasing the demand for coal, and investment in new renewable technologies increases, including geothermal and offshore wind. Oil-fired generation also increases substantially, because it is less expensive to use distillate than natural gas even in some newer combined-cycle plants. Total electricity generation is 6 percent lower in the combined limited case than in the reference case, as higher costs for fuel and for plant construction result in higher prices and lower demand for electricity.

The technology mix for new capacity additions differs dramatically among the three limited cases (Figure 16). In the limited electricity generation supply case, the only new coal-fired builds are those currently under construction, and almost all the additional coal-fired plants projected to be built in the reference case are replaced by new natural-gas-fired capacity (an additional 60 gigawatts). Nuclear generating capacity is the same as in the reference case, and renewable capacity additions are 8 gigawatts higher.

Figure 16. New generating capacity additions in four cases, 2006-2030 (gigawatts)



In the limited natural gas supply case, higher natural gas prices reduce natural-gas-fired capacity additions, while additions of coal-fired, renewable, and nuclear capacity increase relative to the reference case. Because more older generating units are retired in the limited natural gas supply case (primarily, those using natural gas) more new capacity is added than in the reference case.

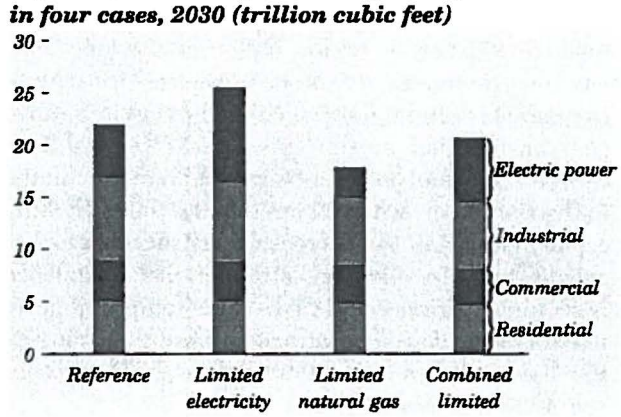
In the combined limited case, 17 gigawatts of new coal-fired capacity with CCS is built. Natural-gas-fired capacity also increases relative to the reference case, but by a smaller amount than is projected in the limited electricity generation supply case. More new capacity using renewable technologies that are not constrained by assumption, including geothermal, landfill gas, and offshore wind, is built in the combined case than in the reference case, even though their construction costs are assumed to be higher than in the reference case.

Natural Gas Consumption

Natural gas consumption for electric power generation in 2030 varies widely across the cases, from 43 percent below the reference case level in the limited natural gas supply case to 78 percent above the reference case level in the limited electricity generation supply case (Figure 17). The largest difference from the reference case is in the limited electricity generation supply case, because constraints on competing fuels, such as the CCS requirement for new coal-fired plants, make natural gas the fuel of choice for new capacity.

In the limited electricity generation supply case, natural gas consumption for electricity generation is 3.9 trillion cubic feet above the reference case level in 2030, while total U.S. natural gas consumption in

Figure 17. Natural gas consumption by sector in four cases, 2030 (trillion cubic feet)



2030 is only 3.6 trillion cubic feet higher than in the reference case. Higher natural gas prices in the limited electricity generation supply case reduce residential, commercial, and industrial natural gas consumption in 2030 by a total of 0.4 trillion cubic feet from the reference case projection.

In the limited natural gas supply case, where only natural gas supply is constrained, higher natural gas prices cause natural gas to lose market share in all the end-use consumption sectors. In 2030, total natural gas consumption is 3.8 trillion cubic feet less in the limited natural gas supply case than in the reference case. In the electric power sector, which is particularly fuel flexible and price sensitive, natural gas consumption in 2030 is 2.2 trillion feet lower than in the reference case.

In the combined limited case, total natural gas consumption in 2030 is 3 percent lower than projected in the reference case, although natural gas use for electricity generation is 21 percent (1.1 trillion cubic feet) higher than in the reference case. In comparison, natural gas consumption in the electric power sector in 2030 is 3.9 trillion cubic feet higher in the limited electricity generation supply case and 2.2 trillion cubic feet lower in the limited natural gas supply case than in the reference case. The constraints on other sources of electricity generation in the limited electricity generation supply case thus have a much more pronounced effect on natural gas consumption in the electric power sector than do the natural gas supply constraints in the limited natural gas supply case.

In all three cases, higher natural gas prices reduce natural gas consumption in the residential, commercial, and industrial sectors relative to the reference case. In the combined limited case, natural gas consumption in the end-use sectors in 2030 is 14 percent lower than in the reference case. In the short term there is little potential in those sectors for fuel switching, which generally occurs only over the long term as older equipment is retired. In the residential and commercial sectors, most of the reduction in natural gas consumption in the three cases results from conservation and more efficient appliances. In the industrial sector, where there is some fuel-switching capability, part of the decrease is attributable to fuel substitution. In addition, although not quantified here, higher prices could drive some industrial users to either shut down operations or move them outside the United States to locations where fuel and other operating costs are lower.

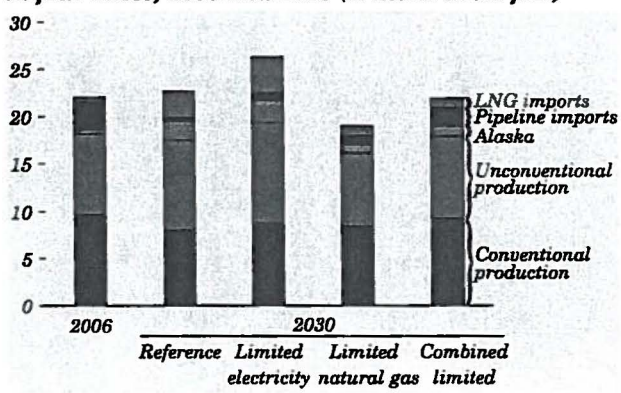
In the end-use sectors, the largest reduction in natural gas consumption occurs in the combined limited case, because the highest natural gas prices are also projected in the combined case. In 2030, natural gas consumption is 19 percent lower in the industrial sector, 8 percent lower in the residential sector, and 10 percent lower in the commercial sector than projected in the reference case.

Natural Gas Supply

As consumption patterns shift across the cases, the mix of natural gas supply sources changes considerably (Figure 18). These changes are dictated largely by the natural gas supply conditions assumed in the limited natural gas supply case and in the combined limited case, which assumes that no Alaska natural gas pipeline is built and that gross LNG imports do not increase after 2009. Consequently, in these two cases, lower 48 sources provide most of the incremental natural gas supply.

In the limited electricity generation supply case, all natural gas sources contribute to incremental supply in 2030. The largest increase is 1.1 trillion cubic feet from unconventional natural gas production, which consists of tight gas, shale gas, and coalbed methane. Unconventional natural gas makes up the bulk of the undiscovered resource base and shows significant growth in the reference case projections. Conventional natural gas production (onshore and offshore) in 2030 is 0.6 trillion cubic feet above the reference case level. Alaskan production and LNG imports, which are not constrained in this case, both respond to higher prices, increasing by 0.4 and 1.0 trillion cubic feet, respectively. Offshore production is slightly higher, by 0.2 trillion cubic feet, and pipeline imports are higher by 0.4 trillion cubic feet.

Figure 18. Natural gas supply by source in four cases, 2006 and 2030 (trillion cubic feet)



warmer than the average, indicating a larger change for summer than for winter weather over the past 15 years. This suggests that the 30-year average is heavily weighted by years before 1993 and is less representative of heating and cooling degree-days in more recent years.

The recent changes in average heating and cooling degree-days have not only affected the accuracy of *AEO* projections for heating and cooling demand. Underestimating summer demand for cooling—particularly, peak demand—can undermine the plans made by electricity producers for wholesale power purchases and capacity additions. Overestimating winter demand for heating can affect plans for natural gas storage and supply. Consequently, many energy analysts have suggested that shorter time periods provide a more appropriate basis for projecting "normal" weather. For example, Cambridge Energy Research Associates, Inc., now uses a 15-year period (1991-2005) to estimate normal weather in its projections for heating and cooling degree-days [*63*], and NOAA, responding to customer feedback, has undertaken a process to revise its traditional 30-year average by creating "optimal climate normals" that will be more representative of current weather trends [*64*]. EIA decided to use the 10-year average to provide a better match with recent trends in heating and cooling degree-days.

Heating and Cooling Degree-Days in AEO2008

All the *AEO2008* projections use the 1997-2006 average as a proxy for normal weather from 2009 through 2030. The 10-year average is based on heating and cooling degree-day data by State, provided by NOAA, and State population weights provided by the U.S. Census Bureau. The State population projections allow for dynamic estimates of heating and cooling degree-days at the Census Division level. Where State populations are expected to shift within and across Census Divisions, the projections for average heating and cooling degree-days at the national level can vary from year to year.

Figure 22 shows differences in heating and cooling degree-days in the *AEO2008* projection for 2010-2030 from the 1971-2000 30-year average published by NOAA. (It should be noted that the projection is not based on any assumption about global warming. Rather, expected U.S. population shifts cause the numbers of average heating and cooling degree-days to change over the projection period.) In 2010, the number of U.S. cooling degree-days in the *AEO2008* reference case is about 10 percent greater than the NOAA 30-year average with fixed population weights, and the number of heating degree-days is 8 percent less [*65*]. Accordingly, electricity providers are projected to see more peak summer demand, and direct fuel use for heating in buildings is projected to decline through 2030 as a result of State population shifts, all else being equal.

Impacts on the AEO2008 Projections

Fuel Use in Buildings and for Electricity Generation

Because space heating accounts for more direct energy use in buildings than does cooling, use of the 10-year averages for heating and cooling degree-days results in a 2.4-percent net decrease (about 0.6 quadrillion Btu) in buildings sector energy consumption in 2030, as compared with the same projection based on 30-year average heating and cooling degree-days (Figure 23). For electricity providers, on the other hand, the increase in electricity use for

Figure 21. Annual heating and cooling degree-days, 1993-2007 (percent difference from 30-year average)

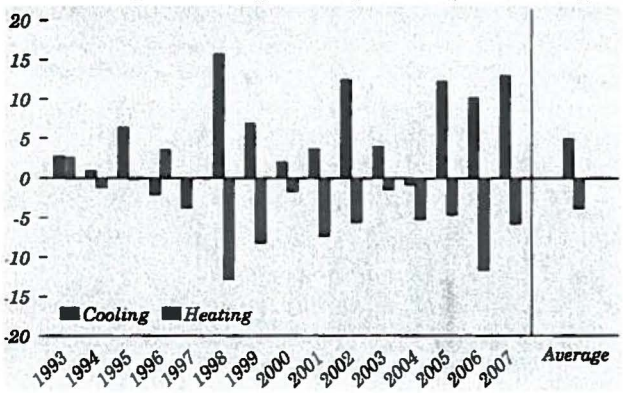
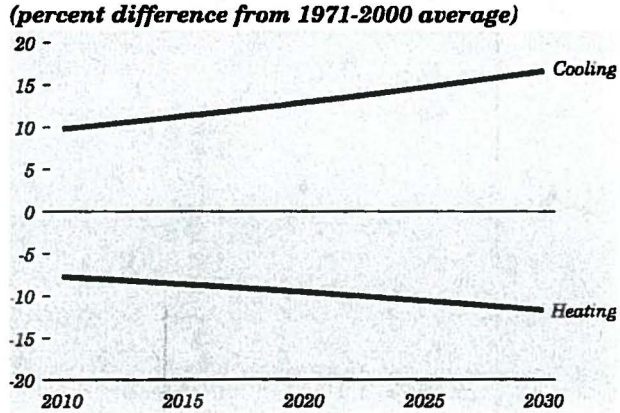


Figure 22. Heating and cooling degree-days in the AEO2008 reference case, 2010-2030 (percent difference from 1971-2000 average)



cooling is more than the decrease in electricity use for heating, and the result is a 0.7-percent net increase (about 0.4 quadrillion Btu) in fuel use for electricity generation. The effect on total net energy consumption in the reference case is small, amounting to a 0.4-percent decrease (about 0.4 quadrillion Btu) in 2030. As a result, expenditures for energy purchases in residential and commercial buildings are 0.4 percent lower in 2030 ($1.8 billion in 2006 dollars), and total CO_2 emissions in 2030 are reduced by 0.1 percent (10 million metric tons).

Electricity Prices

As expected, the additional summer demand for cooling that results from using the 10-year average for cooling degree-days shifts more electricity demand into the summer peak period (Figure 24). In 2030, demand in the summer peak period increases by 4.4 percent, whereas winter demand is reduced by 0.8 percent. The increase in summer peak demand leads to higher real electricity prices, with average increases of 2.3 percent for residential customers and 0.3 percent for commercial customers.

Liquefied Natural Gas: Global Challenges

U.S. imports of LNG in 2007 were more than triple the 2000 total, and they are expected to grow in the long term as North America's conventional natural gas production declines. With U.S. dependence on LNG imports increasing, competitive forces in the international markets for natural gas in general and LNG in particular will play a larger role in shaping the U.S. market for LNG. Key factors currently shaping the future of the global LNG market include the evolution of project economics, worldwide demand for natural gas, government policies that affect the development and use of natural resources in countries with LNG facilities, and changes in seasonal patterns of LNG trade.

Changing Project Economics

From the mid-1990s through 2002, a major factor underlying the growth of global LNG markets was declining costs throughout the LNG supply chain. Since 2003, however, costs have escalated, especially in the area of liquefaction. The result has been a delay in commitments to the construction of new liquefaction capacity, which in turn creates uncertainty about the future availability of LNG supplies.

The cost of liquefaction capacity can vary widely, depending on location, quality of natural gas supplies, and plant design (including whether the planned capacity is an expansion of an existing plant or a new greenfield plant). In general, however, the available data indicate that construction costs for new liquefaction capacity have more than tripled since the early 2000s [*66*]. Some of the reasons for the increase are higher raw material costs for commodities such as nickel and steel, a shortage of experienced workers and contractors, full construction order books, and longer delivery times for key pieces of equipment. Although economies of scale can reduce unit costs, those reductions have not been sufficient to offset increases in other costs.

For regasification facilities and receiving terminals, the available data suggest that the construction costs for new projects have increased by more than 50 percent over the past 5 years [*67*]. In addition, construction costs for LNG tankers have increased by 40 to 50 percent since 2003 [*68*], primarily because of rising

Figure 23. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on energy use for heating and cooling in buildings by fuel type, 2030 (quadrillion Btu)

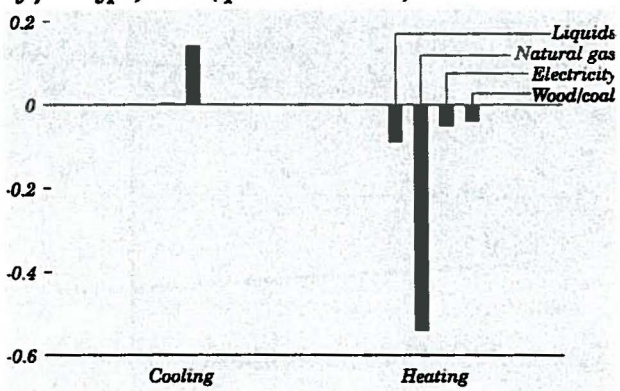
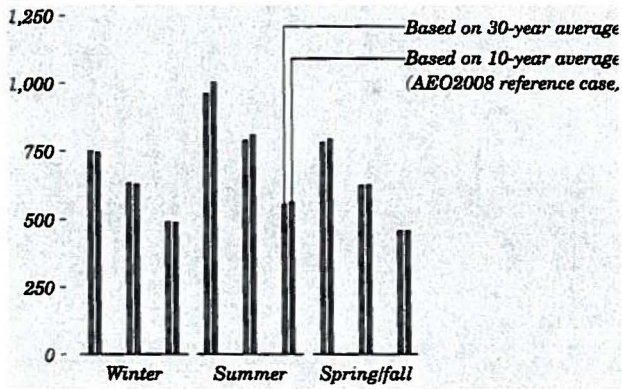


Figure 24. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on peak seasonal electricity demand load, 2030 (gigawatts)



costs for materials and equipment. Wood Mackenzie reports that ship prices remain on "an upward trend driven by a surge in new orders of large tankers, bulk carriers, and containerships, which compete with LNG carriers for berth space" [*69*].

Worldwide Demand for Natural Gas

Contributing to the uncertainty about LNG supply availability is a worldwide increase in natural gas consumption and its effect on prices. In EIA's *International Energy Outlook 2007*, annual worldwide natural gas consumption in 2030 varies by 35 trillion cubic feet between the high and low macroeconomic growth cases, or around plus or minus 11 percent when compared with the reference case [*70*].

For some countries, such as Japan and South Korea, relatively slow growth is expected for natural gas consumption, but because they are almost entirely dependent on LNG imports to meet natural gas demand, any increase is likely to affect LNG markets. For India and China, on the other hand, natural gas consumption has increased much more rapidly. Both countries have been actively searching for new domestic natural gas resources, and both have been pursuing pipeline projects that could bring more imported supplies to domestic consumers. China has been negotiating with Russia to obtain supplies, India has been negotiating with Iran, and both countries have been competing for pipeline supplies from Central Asia and Myanmar. The success or failure of domestic natural gas exploration efforts in India and China and the possible construction of new pipelines is likely to affect their demand for LNG imports and, ultimately, how much LNG will be available to the United States.

Currently, the Organization for Economic Cooperation and Development (OECD) countries account for the majority of LNG imports. In 2006, 12 OECD countries [*71*] were net importers of LNG, and they accounted for just over 90 percent of all LNG imports. Five non-OECD countries [*72*] accounted for the remaining 10 percent. Among the world's net exporters of LNG, however, 11 of 12 were non-OECD countries [*73*], and Australia was the only OECD country with net LNG exports in 2006. At the same time, natural gas consumption has been increasing at a faster rate in the non-OECD countries than in the OECD countries as a whole.

Resource Development Policies

In addition to the uncertainty associated with natural gas demand growth and project costs, many countries that are net LNG exporters have government policies or agreements that promote domestic natural gas consumption. Any expansion (or rollback) of such policies could affect their future domestic consumption of natural gas and the supplies available for export.

Indonesia, Egypt, and Australia have or are considering domestic natural gas supply requirements for projects under development. Indonesia's 2001 Oil and Gas Law imposes a 25-percent domestic market obligation on new contracts for natural gas production sharing, although implementation of the law is still uncertain [*74*]. In 2005, Egypt reduced the portion of natural gas reserves available for export from one-third to one-quarter.

Unlike Egypt and Indonesia, Australia does not have any national regulations that require natural gas resources to be reserved for domestic markets; however, the Western Australia state government has negotiated an agreement with Northwest Shelf LNG developers to reserve 4.7 trillion cubic feet of Northwest shelf natural gas for the domestic market and, more recently, has negotiated a similar agreement with Gorgon LNG developers to set aside 15 percent of reserves for the domestic market. The Western Australia government has also been considering domestic reservation requirements for all future natural gas projects that would liquefy production for export [*75*]. Such a requirement could discourage development of marginal export projects, leaving some resources undeveloped.

Domestic reservation requirements promote natural gas consumption by keeping domestic natural gas prices low. In addition, many countries that are net LNG exporters foster domestic consumption further by directly regulating domestic natural gas prices and keeping them below LNG net-back equivalent prices. Both China and India, two of the world's newest LNG importers, also regulate the prices that electricity generators pay for natural gas. Without below-market prices, generators probably would be unable to use natural gas to generate power profitably for sale to domestic electricity markets, where prices also are regulated.

Seasonal Usage Patterns

The natural gas market in North America, where indigenous production meets much of the demand for natural gas, is a large, liquid market with ample storage capacity. Thus, even during periods of relatively low demand, it can still absorb imports. There

is, however, a seasonal element specific to the U.S. market (Figure 25). More LNG is imported by the United States during the summer months, for reasons related as much to conditions in other LNG-importing countries as to conditions in the United States. The conditions that make North America an attractive year-round market are not likely to change, but changing conditions in the rest of the world could reduce the availability of summer LNG imports to the United States.

The natural gas market in OECD Europe is comparable with the North American market in size—about 71 percent as large in 2005. Whereas North America relies almost entirely on storage withdrawals to meet incremental winter demand, OECD Europe employs a variety of sources, with indigenous production, natural gas imports, and storage withdrawals all rising in the winter months to meet increased demand (Figure 26).

The United Kingdom, Belgium, and the Netherlands currently have active market-based systems for natural gas. In addition, European Union regulators are trying to introduce regulatory reform into additional markets and bring more liquidity into continental European markets. Although OECD Europe also has less storage capacity than North America, even when the relative size of annual demand in the two markets is taken into account, it has many geologic structures that could be suitable for seasonal natural gas storage. By 2015, OECD Europe could add almost 1 trillion cubic feet of additional working natural gas capacity in seasonal storage facilities [76].

The seasonal LNG supplies available to the North American market could also be affected if new importers of LNG develop in the southern hemisphere, where peak demand for heating occurs during the northern hemisphere's summer. Argentina became the first South American country to import LNG, offloading its first partial cargo in May 2008. Argentina and its neighbors are anticipating a shortage of natural gas this winter (June-August), and Argentina is planning to import LNG on special ships with onboard regasification capability while the construction of onshore regasification terminals is being discussed.

Brazil and Chile also will soon become LNG importers. Brazil has two floating regasification and storage units on order, the first of which could begin operation on the country's northeast coast during 2008. Chile has at least one regasification terminal in the advanced planning stage, and others are under consideration. The terminal planned for Quinteros, Chile, is expected to enter service in the second quarter of 2009 with a capacity of 2.5 million tons of LNG (116 billion cubic feet of natural gas) per year and a contract with BG Group for supply of 1.7 million tons (79 billion cubic feet) per year [77].

Implications of Uncertainty in LNG Markets

Changing expectations about global LNG demand, supply, and prices are reflected in the *AEO2008* reference case. Demand for natural gas overall is lower in *AEO2008* than in *AEO2007* as a result of expectations for slower economic growth and higher energy prices, including natural gas prices. With the additional assumptions of higher LNG costs, stronger competition for global LNG supplies, and growing constraints on LNG production, U.S. LNG imports in 2030 are 1.7 trillion cubic feet lower in *AEO2008* than the *AEO2007* projection for LNG imports in 2030. There remains, however, considerable uncertainty

Figure 25. U.S. imports of liquefied natural gas, 2001-2007 (billion cubic feet per day, 3-month average)

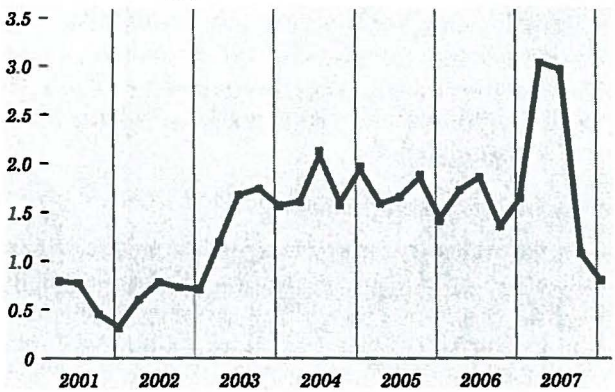
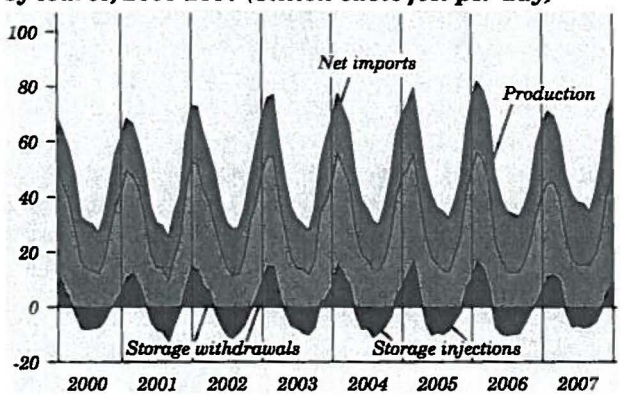


Figure 26. OECD Europe natural gas supply by source, 2000-2007 (billion cubic feet per day)



about the future of the global LNG market, which could lead to higher or lower LNG imports. To quantify the possible effects of that uncertainty, *AEO2008* includes high and low LNG supply cases in which U.S. imports of LNG are assumed to be higher and lower, respectively, than in the reference case.

The high and low LNG supply cases are not based on explicit assumptions about the causes of increased or decreased availability of LNG imports but only examine their potential impacts on natural gas supply, demand, and prices in the United States. Gross U.S. LNG import levels were specified for the high LNG supply case by increasing LNG imports by 10 percent in 2011 relative to the reference case level, followed by a gradual increase to three times the reference case level in 2030. For the low LNG supply case, U.S. LNG imports are held constant at the reference case level in 2009 through the end of the projection. All other assumptions in the LNG supply cases, such as oil prices and domestic resource levels, are the same as in the reference case. In 2030, LNG imports are specified to be 8.5 trillion cubic feet in the high LNG supply case and 1.0 trillion cubic feet in the low LNG supply case (Figure 27).

Varying the amount of LNG imports affects domestic production, consumption, and price levels for natural gas. In general, lower LNG imports result in the use of higher priced domestic production, leading to higher prices and, subsequently, reduced consumption and total supply requirements. In the low LNG supply case, 23 percent of the reduction in LNG imports is made up by a decline in natural gas consumption (primarily in the electricity generation sector, where more than 90 percent of the reduction occurs). The other 77 percent is made up by an increase in supplies from other sources, primarily domestic unconventional natural gas production (26 percent) but also other domestic lower 48 production (20 percent), Alaska production (20 percent), and pipeline imports (11 percent) (Figure 28). The lower supply requirement helps moderate the price increase relative to the reference case (Figure 29). Wellhead natural gas prices in 2030 are 4.4 percent higher in the low LNG supply case than in the reference case.

In the high LNG supply case, the impact on consumption is larger. An increase in natural gas consumption amounts to about 45 percent of the increment in LNG imports relative to the reference case, and the remaining 55 percent offsets declines in domestic natural gas production and pipeline imports. Wellhead prices in 2030 are nearly 17 percent lower in the high LNG supply case than in the reference case.

Figure 27. Gross U.S. imports of liquefied natural gas in three cases, 1990-2030 (trillion cubic feet)

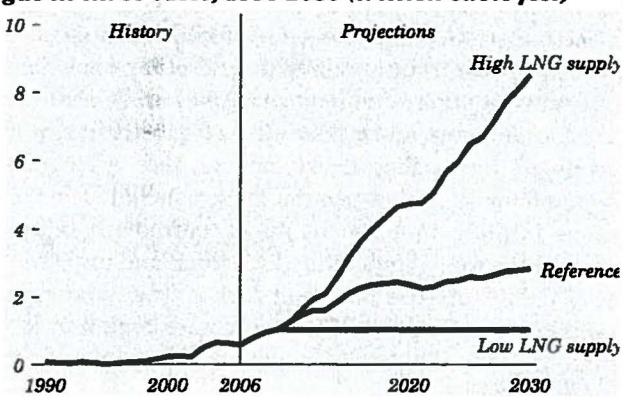


Figure 28. U.S. natural gas supply in three cases, 2006-2030 (trillion cubic feet)

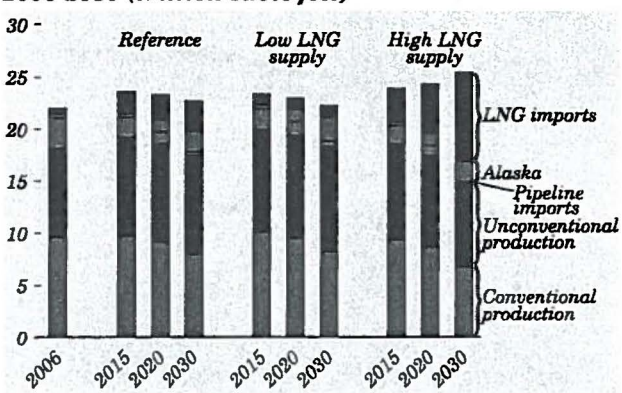
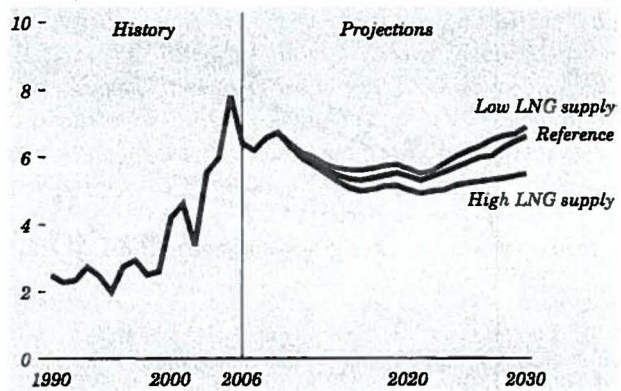


Figure 29. Lower 48 wellhead natural gas prices in three cases, 1990-2030 (2006 dollars per thousand cubic feet)



World Oil Prices and Production Trends in *AEO2008*

AEO2008 defines the world oil price as the price of light, low-sulfur crude oil delivered in Cushing, Oklahoma. Since 2003, both "above ground" and "below ground" factors have contributed to a sustained rise in nominal world oil prices, from $31 per barrel in 2003 to $69 per barrel in 2007. The *AEO2008* reference case outlook for world oil prices is higher than in the *AEO2007* reference case. The main reasons for the adoption of a higher reference case price outlook include continued significant expansion of world demand for liquids, particularly in non-OECD countries, which include China and India; the rising costs of conventional non-OPEC supply and unconventional liquids production; limited growth in non-OPEC supplies despite higher oil prices; and the inability or unwillingness of OPEC member countries to increase conventional crude oil production to levels that would be required for maintaining price stability. EIA will continue to monitor world oil price trends and may need to make further adjustments in future *AEO*s.

In the *AEO2008* reference case, the world oil price in 2030 is approximately 18 percent higher than the *AEO2007* reference case projection. In inflation-adjusted terms (2006 dollars) the world crude oil price reaches $70 per barrel in 2030 in the *AEO2008* reference case, as compared with $61 per barrel in the *AEO2007* reference case (Figure 30).

In *AEO2008*, for both production and consumption, "liquid fuels" include conventional and unconventional liquids. Unconventional liquids include oil sands, biofuels, extra-heavy oils, gas-to-liquids (GTL), and CTL. World consumption of liquid fuels increases from 85 million barrels per day in 2006 to 113 million barrels per day in 2030 in the *AEO2008* reference case. The non-OECD countries, which accounted for 42 percent of world liquids consumption in 2006, are expected to reach 50 percent of the world total in 2022 and 53 percent in 2030, as non-OECD demand for liquid fuels increases from 36 million barrels per day in 2006 to 60 million barrels per day in 2030. Over the same period, OECD consumption increases from 49 million barrels per day to 53 million barrels per day in the reference case (Figure 31).

The OPEC share of world liquids production remains at about 41 percent through 2030, while non-OPEC conventional liquids production increases from 48 million barrels per day in 2006 to 56 million barrels per day in 2030. Unconventional liquids production in both OPEC and non-OPEC countries grows rapidly, but with more substantial increases in the non-OPEC countries (to 11 million barrels per day in 2030, compared with 3 million barrels per day for the OPEC countries in 2030).

Any long-term projection of world oil prices is highly uncertain. Above-ground factors that contribute to price uncertainty include access to oil resources, investment constraints, economic and other objectives of countries where the major reserves and resources are located, cost and availability of substitutes, and economic and policy developments that affect the demand for oil. Below-ground factors include the volumes initially in place in major petroleum basins around the world (including discovered and undiscovered fields) and the fluid and rock characteristics of undiscovered fields. *AEO2008* includes high and low price cases to illustrate the potential impacts of the uncertainties.

Figure 30. World oil price in six cases, 2000-2030 (2006 dollars per barrel)

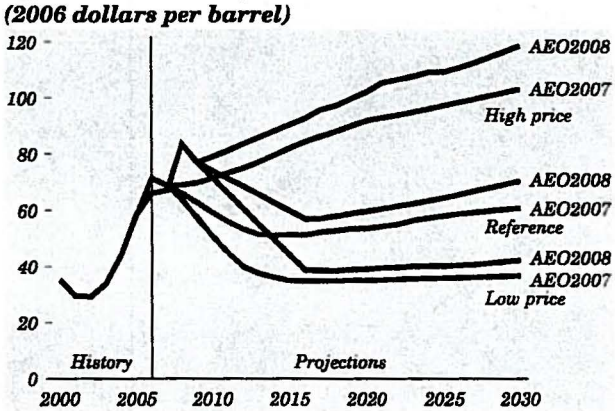
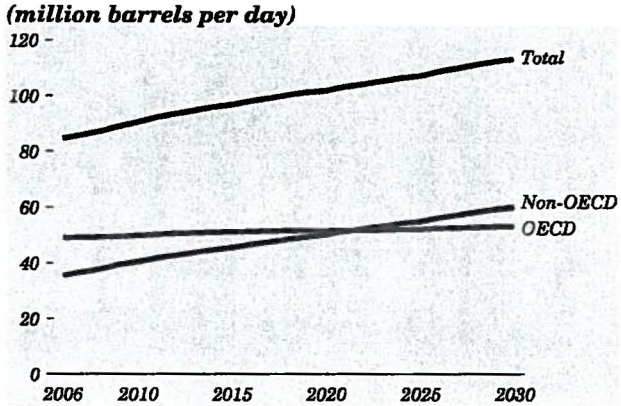


Figure 31. World liquids consumption in the AEO2008 reference case, 2006-2030 (million barrels per day)



The high price case assumes that non-OPEC conventional oil resources are less plentiful, and the overall costs of extraction are higher, than assumed in the reference case. The high price case also assumes that OPEC will choose to allow a decline in its market share to 38 percent of total world liquids production. As a result, the oil price increases steadily to approximately $112 per barrel in 2016 ($93 per barrel in 2006 dollars) and $186 per barrel in 2030 ($119 per barrel in 2006 dollars). World liquids consumption rises from 85 million barrels per day in 2006 to 98 million barrels per day in 2030 in the high price case.

The low price case assumes that non-OPEC conventional oil resources are more plentiful, and the overall costs of extraction are lower, than in the reference case, and that OPEC will choose to increase its market share to 45 percent. In the low price case, the world oil price falls steadily, to approximately $47 per barrel in 2017 ($39 per barrel in 2006 dollars), and then rises gradually to $69 per barrel in 2030 ($42 per barrel in 2006 dollars). World liquids consumption rises to 132 million barrels per day in 2030 in the low price case.

Market Trends

The projections in *AEO2008* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend estimates, given known technology and technological and demographic trends. *AEO2008* assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. Unless otherwise noted, laws and regulations are assumed to remain as currently enacted. Further, future laws and regulatory actions are not anticipated.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

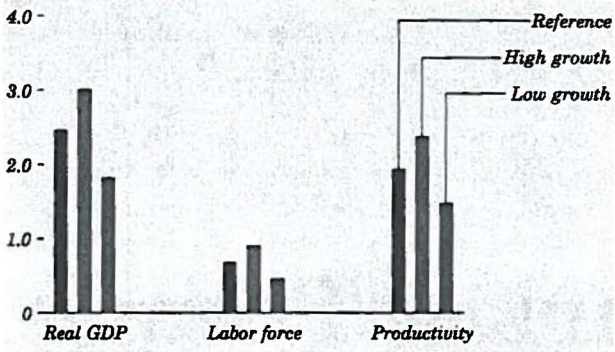
Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2008* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

The *AEO* production process was somewhat different this year. After EIA published an early-release version of the *AEO2008* reference case in December 2007, EISA2007 was enacted later that month. EIA decided to update the reference case to reflect the provisions of EISA2007. The *AEO2008* reference case, released in March 2008, also includes additional revisions that reflect historical data issued after the *AEO2008* early-release reference case was completed, as well as new data from EIA's January 2008 *Short-Term Energy Outlook* (*STEO*), a more current economic outlook, and technical updates to the version of NEMS used to produce the early release.

AEO2008 Presents Three Views of Economic Growth

Figure 32. Average annual growth rates of real GDP, labor force, and productivity, 2006-2030 (percent per year)

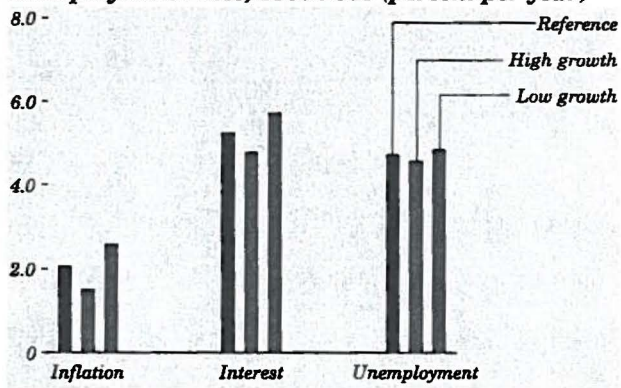


AEO2008 presents three views of economic growth for the 2006-2030 projection period. Economic growth depends mainly on growth in the labor force and productivity. In the reference case, the labor force grows by an average of 0.7 percent per year; labor productivity in the nonfarm business sector grows by 1.9 percent per year; and growth in real GDP averages 2.4 percent per year (Figure 32). In line with the labor and output trends, nonfarm employment grows by 0.9 percent per year, while employment in manufacturing shrinks by 1 percent per year. Investment growth averages 2.8 percent per year in the reference case; disposable income available to households grows by 2.8 percent per year; and disposable income per capita increases by 1.9 percent per year.

The high and low economic growth cases show the effects of alternative economic growth assumptions on the energy market projections (see Appendix E for descriptions of all the alternative cases). In the high growth case, real GDP growth averages 3.0 percent per year, as a result of higher assumed growth rates for the labor force (0.9 percent per year), nonfarm employment (1.2 percent), and nonfarm labor productivity (2.4 percent). With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case. In the low growth case, growth in real GDP is 1.8 percent per year, as a result of lower assumed growth rates for the labor force (0.4 percent per year), nonfarm employment (0.5 percent per year), and labor productivity (1.5 percent per year). Consequently, the low growth case shows higher inflation and interest rates and slower growth in industrial output and employment than are projected in the reference case.

Projected Gains in Labor Productivity Are Higher Than Historical Averages

Figure 33. Average annual inflation, interest, and unemployment rates, 2006-2030 (percent per year)

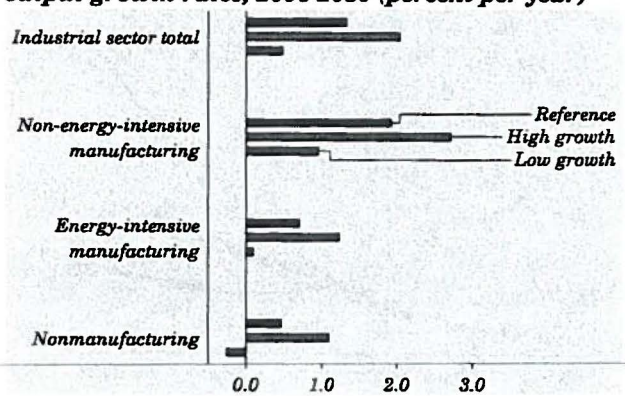


Common indicators for inflation, interest rates and employment are, respectively, the all-urban consumer price index, the interest rate (yield) on 10-year U.S. Treasury notes, and the nonfarm unemployment rate, which are widely viewed as barometers of conditions in the markets for goods and services, credit, and labor, respectively. Historically, from 1982 to 2006, inflation has averaged 3.1 percent per year, the average yield on 10-year Treasury notes has been 7.2 percent per year, and the unemployment rate has averaged 6.1 percent. In the *AEO2008* reference case, as well as in the high and low economic growth cases, projected gains in nonfarm labor productivity—although lower than those seen during the 1990s—are generally higher than the historical averages of the 1980s, leading to more optimistic projections for inflation, interest, and unemployment rates.

In *AEO2008*, the projected average annual inflation rate over the 2006-2030 period is 2.1 percent in the reference case, 1.5 percent in the high economic growth case, and 2.6 percent in the low growth case (Figure 33). Annual yields on the 10-year Treasury note are projected to average 5.2 percent in the reference case, 4.8 percent in the high growth case, and 5.7 percent in the low growth case. The projections for average unemployment rates are 4.7 percent in the reference case, 4.6 percent in the high growth case, and 4.9 percent in the low growth case. Relative to the reference case, the higher inflation, interest, and unemployment rates in the low growth case and the lower rates in the high growth case depend on different assumptions about labor productivity and population growth rates.

Output Growth for Energy-Intensive Industries Is Expected To Slow

Figure 34. Sectoral composition of industrial output growth rates, 2006-2030 (percent per year)



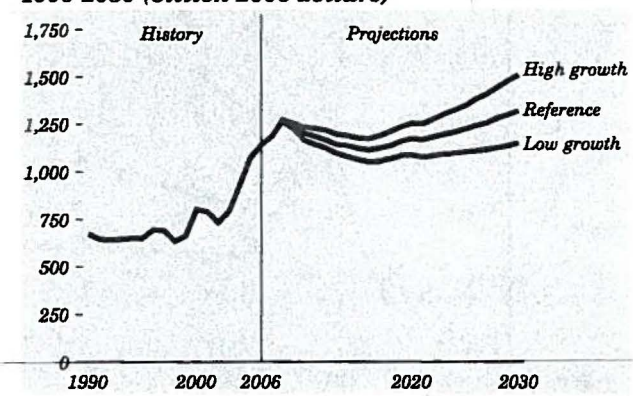
With imports meeting a growing share of demand for industrial goods, the industrial sector has shown slower output growth than the economy as a whole in recent decades. That trend is expected to continue in the *AEO2008* projections. The average annual growth rate for real GDP from 2006 to 2030 is 2.4 percent in the reference case, whereas the industrial sector averages 1.3 percent. With higher energy prices and greater foreign competition, the energy-intensive manufacturing sectors [78] grow by only 0.7 percent per year from 2006 through 2030, compared with a 1.9-percent average annual rate of growth for the remaining industrial sectors (Figure 34).

AEO2008 projects relatively slow growth in construction, chemicals, and transportation equipment. High interest rates affect the construction and transportation equipment sectors. Increased foreign competition, slow expansion of domestic production, and higher energy prices exert competitive pressure on the chemicals industry, with growth slowing substantially after 2020.

In the high economic growth case, output from the industrial sector grows by an annual average of 2.0 percent, still below the annual growth of real GDP (3.0 percent). In the low economic growth case, real GDP and industrial output grow by 1.8 and 0.5 percent per year, respectively. In both cases, the non-energy-intensive manufacturing industries show higher growth than the rest of the industrial sector.

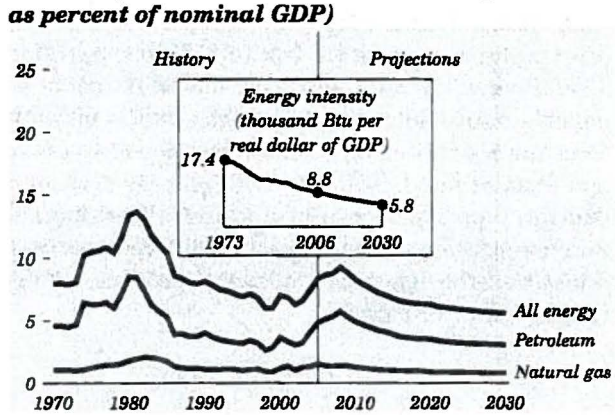
Energy Expenditures Relative to GDP Are Projected To Decline

Figure 35. Energy expenditures in the U.S. economy, 1990-2030 (billion 2006 dollars)



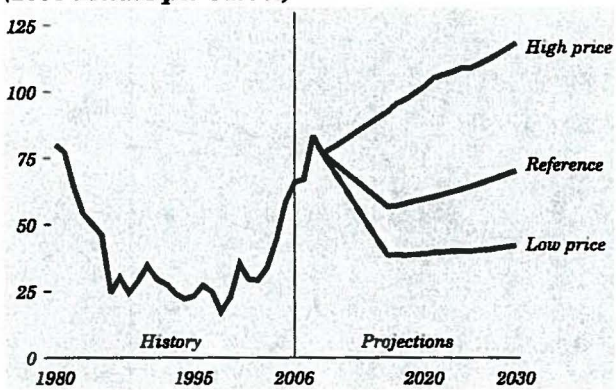
Total U.S. energy expenditures were $1.1 trillion in 2006. Energy expenditures rise to $1.3 trillion (2006 dollars) in 2030 in the *AEO2008* reference case and to $1.5 trillion in the high economic growth case (Figure 35). For the economy as a whole, ratios of energy expenditures to GDP in 2006 were 8.6 percent for all energy, 5.1 percent for petroleum, and 1.4 percent for natural gas. Recent developments in the world oil market have pushed the energy expenditure shares upward, and in the reference case they are expected to increase from current levels until 2010. After 2010 expenditures fall, as the energy intensity of the U.S. economy—measured in terms of energy consumption (thousand Btu) per dollar of real GDP—continues to decline and world oil prices stabilize. Total energy expenditures are projected to equal 5.6 percent of GDP in 2030, petroleum expenditures 3.1 percent, and natural gas expenditures less than 1 percent (Figure 36).

Figure 36. Energy expenditures as a share of gross domestic product, 1970-2030 (nominal expenditures as percent of nominal GDP)



Oil Price Cases Show Uncertainty in Prospects for World Oil Markets

Figure 37. World oil prices, 1980-2030 (2006 dollars per barrel)

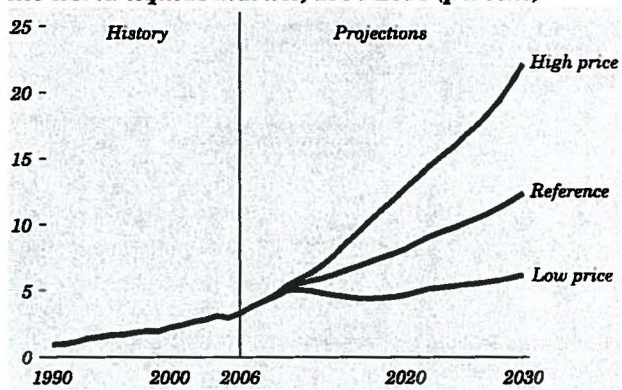


World oil price projections in *AEO2008*, in terms of the average price of imported low-sulfur, light crude oil to U.S. refiners, are higher for 2006-2030 than those presented in *AEO2007*. The higher price path reflects lower estimates of oil consumers' sensitivity to higher prices, an anticipation of lower additions to production capacity in key non-OPEC regions, and a reassessment of OPEC producers' willingness and ability to expand production and production capacity aggressively.

The historical record shows substantial variation in world oil prices, and there is arguably even more uncertainty about future prices when longer time periods are examined. As in previous outlooks, *AEO2008* considers three price cases to illustrate the uncertainty of prospects for future world oil resources. In the reference case, world oil prices moderate from current levels to about $57 per barrel in 2016, start rising again as production in non-OPEC regions peaks, and continue rising to $70 per barrel in 2030 (all prices in 2006 dollars). The low and high price cases reflect a wide band of potential world oil price paths, ranging from $42 to $119 per barrel in 2030 (Figure 37), but they do not bound the set of all possible future outcomes. The high and low oil price cases are predicated on assumptions about access to and costs of non-OPEC oil, OPEC supply decisions, and the supply potential of unconventional liquids. Combining those assumptions with different assumptions about the demand for oil would produce a wider range of oil price paths.

Unconventional Resources Gain Market Share as Prices Rise

Figure 38. Unconventional resources as a share of the world liquids market, 1990-2030 (percent)



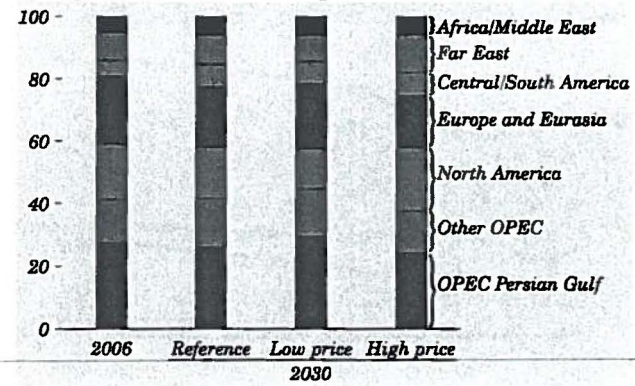
The world's total production of liquid fuels from unconventional resources in 2006 was 2.8 million barrels per day, equal to about 3 percent of total liquids production. Production from unconventional sources included 1.2 million barrels per day from oil sands in Canada, 600,000 barrels per day from very heavy oils in Venezuela, and 320,000 barrels of ethanol per day in the United States. In the *AEO2008* reference case, unconventional production makes up 12 percent (14 million barrels per day) of total liquids production in 2030 (Figure 38).

Depending on price assumptions, world unconventional production is projected to be 5.4 to 18.9 million barrels per day higher in 2030 than it was in 2006, accounting for between 6 and 22 percent of the world's total production of liquids. Production of unconventional liquids depends heavily on prices, being more competitive with conventional sources when market prices are high. Not all unconventional liquids respond to price changes in the same manner, however, because the sources of unconventional liquids differ with regard to resource constraints, political backing, available technologies, and other characteristics.

The composition of world unconventional liquids production does not vary significantly between the reference and low price cases, with biofuels and oil sands combined accounting for about 60 percent of unconventional supply. In the high price case, the economic viability of and need for unconventional liquids supply increase, and 34 percent of total projected unconventional liquids production in 2030 is accounted for by CTL, one-half of which will be produced by China.

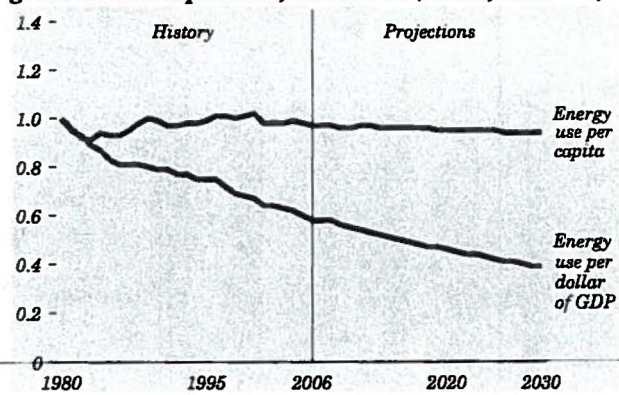
World Liquids Supply Is Projected To Remain Diversified in All Cases

Figure 39. World liquids production shares by region, 2006 and 2030 (percent)



Average Energy Use per Person Levels Off Through 2030

Figure 40. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



In 2006, OPEC producers in the Persian Gulf accounted for 28 percent of the world's conventional liquids supply, and other OPEC producers accounted for 14 percent. Europe and Eurasia produced 22 percent of conventional supply, North America 17 percent, and the rest of the world 19 percent (Figure 39).

In the reference case, OPEC conventional production maintains approximately a 40-percent share of world total liquids supply through 2030, which is consistent with recent historical trends and reflects an expectation that OPEC suppliers will vary their production levels to influence world oil prices. In all the *AEO2008* cases, OECD liquids production is between 23 and 24 million barrels per day in 2030, constrained by resource availability rather than price or political concerns.

In the high price case, several resource-rich countries, including Saudi Arabia, Mexico, and Russia, limit production, lowering both total world liquids supply and their own shares of the supply. In the high price case, the largest increases in liquids production occur in the United States, China, Canada, Brazil, and India, where substantial increases in unconventional production are expected, underscoring the rising importance of unconventional fuels to the world's supply of liquids. In the low price case, resource-rich countries either maintain current production behavior or increase their openness to foreign capital investment. As a result, the largest increases in world liquids supply shares in the low price case occur in Iraq and the Caspian Sea Basin.

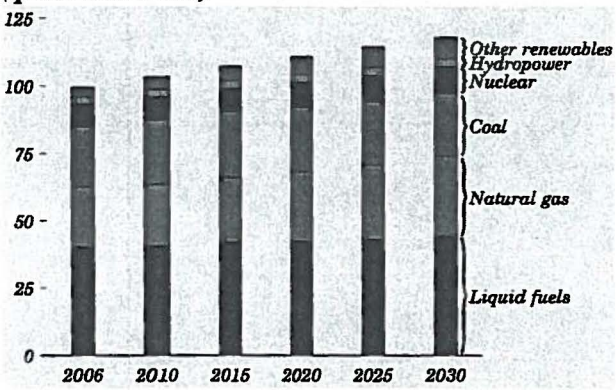
Because energy use for housing, services, and travel in the United States is closely linked to population levels, energy use per capita is relatively stable (Figure 40). In addition, the economy is becoming less dependent on energy in general.

Energy intensity (energy use per 2000 dollar of GDP) declines by an average of 1.4 percent per year in the low growth case, 1.7 percent in the reference case, and 1.9 percent in the high growth case. Efficiency gains and faster growth in less energy-intensive industries account for most of the projected decline, more than offsetting growth in demand for energy services in buildings, transportation, and electricity generation. The decline is more rapid in the high economic growth case, because with higher economic growth the number of new, more efficient systems grows faster, and the additional growth is concentrated in less energy-intensive industries. As energy prices moderate over the longer term, energy intensity declines at a slower rate in the reference, high growth, and low growth cases.

The *AEO2008* cases developed to illustrate the uncertainties associated with those factors include low and high growth cases, low and high price cases, and alternative technology cases (see Appendixes B, C, D, and E).

Coal and Liquid Fuels Lead Increases in Primary Energy Use

Figure 41. Primary energy use by fuel, 2006-2030 (quadrillion Btu)



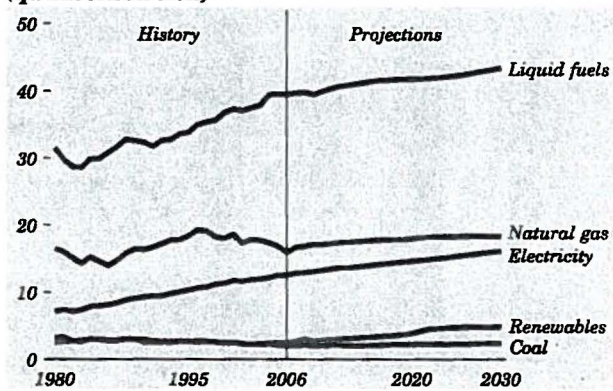
Total primary energy consumption, including energy for electricity generation, grows by 0.7 percent per year from 2006 to 2030 in the reference case (Figure 41). Fossil fuels account for 55 percent of the increase. Coal use increases in the electric power sector, where electricity demand growth and current environmental policies favor coal-fired capacity additions. About 54 percent of the projected increase in coal consumption occurs after 2020, when higher natural gas prices make coal the fuel of choice for most new power plants under current laws and regulations, which do not limit greenhouse gas emissions. Increasing demand for natural gas in the buildings and industrial sectors offsets the decline in natural gas use in the electricity sector after 2016, resulting in a net increase of 5 percent from 2006 to 2030.

The transportation sector accounted for more than two-thirds of all liquid fuel consumption in 2006, and 60 percent of that share went to LDVs. Demand for liquid transportation fuels increases by 17 percent from 2006 to 2030, dominated by growing fuel use for LDVs, trucking, and air travel. The industrial sector accounted for 25 percent of total liquid fuel use in 2006, but its share declines to 21 percent in 2030.

AEO2008 also projects rapid percentage growth in renewable energy production, as a result of the EISA2007 RFS and the various State mandates for renewable electricity generation. Additions of new nuclear power plants are also projected, spurred by improving economics relative to plants fired with fossil fuels and by the EPACT2005 PTCs.

Electricity and Liquid Fuels Lead Rise in Delivered Energy Consumption

Figure 42. Delivered energy use by fuel, 1980-2030 (quadrillion Btu)



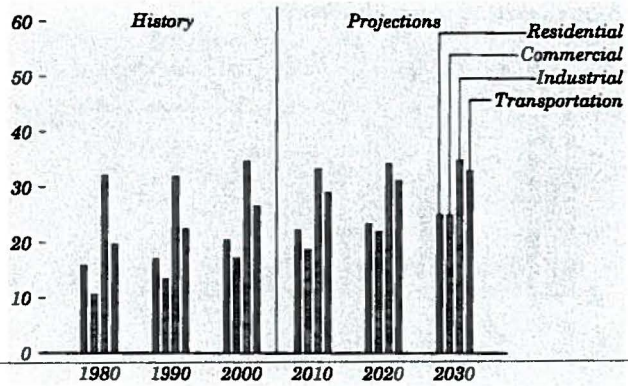
Delivered energy use (excluding losses in electricity generation) grows by 0.7 percent per year from 2006 to 2030 in the reference case. The growth in electricity use is driven by growing demand in the residential and commercial sectors. With the growing market penetration of electric appliances, residential electricity use increases slightly faster than the total number of households, and commercial electricity use outpaces the growth in commercial floorspace. With different assumptions about population and economic growth, average annual growth in delivered energy use from 2006 to 2030 ranges from 0.3 percent in the low growth case to 1.0 percent in the high growth case.

Growth in demand for liquid fuels is led by the transportation sector, as rising population, incomes, and economic output boost demand for travel, partially offsetting improvements in vehicle efficiency (Figure 42). Natural gas use grows more slowly than overall delivered energy demand, reflecting its relatively higher cost, particularly in the industrial sector.

Industrial biomass accounts for the largest share of end-use consumption of renewable energy. Currently it is used mostly as a byproduct fuel in the pulp and paper industry, but that use will be surpassed by consumption of biomass heat and co-products from ethanol manufacture when the biofuel mandate under EISA2007 reaches 36 billion gallons in 2022. Consumption of nonmarketed solar, geothermal, and wind energy also increases dramatically in the projections; however, it continues to account for less than 1 percent of all delivered energy use in the residential and commercial sectors.

U.S. Primary Energy Use Climbs to 118 Quadrillion Btu in 2030

Figure 43. Primary energy consumption by sector, 1980-2030 (quadrillion Btu)



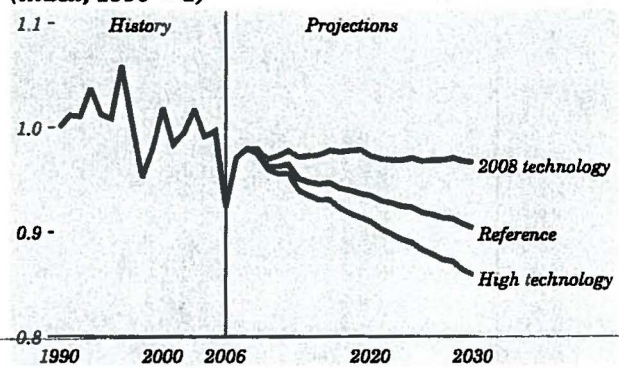
The most significant impact of EISA2007 is in the transportation sector, where the CAFE standard for LDVs is raised to 35 mpg in 2020. Still, from 2006 to 2030 the transportation sector sees the second-largest increase in energy consumption, at 5 quadrillion Btu (Figure 43), as a result of increases in vehicle miles traveled, jet fuel consumption, and demand for fuels such as E10, E85, and diesel to displace motor gasoline.

EISA2007 has little effect on the commercial sector, where energy demand continues to expand more rapidly than the economy as a whole. Dependence on natural gas and electricity, already heavy in the residential and commercial sectors, increases over time. Demand for electricity grows faster than demand for natural gas in both sectors, however, because electricity is used for a wider diversity of applications (including the fastest growing end uses, office equipment, personal computers, and televisions), whereas natural gas is used mainly for space heating, cooking, and water heating, which grow more slowly than households and floorspace.

The variation in residential and commercial energy demand between the high and low price cases is relatively small, and natural gas consumption accounts for most of the difference. In the industrial sector, fuel use in 2030 is higher in the high price case than in the reference case, reflecting differences in CTL, ethanol, and biodiesel production. Different growth rates for manufacturing output in the low and high macroeconomic growth cases account for most of the difference in industrial energy consumption between the two cases.

Residential Energy Use per Capita Varies With Technology Assumptions

Figure 44. Residential delivered energy consumption per capita, 1990-2030 (index, 1990 = 1)

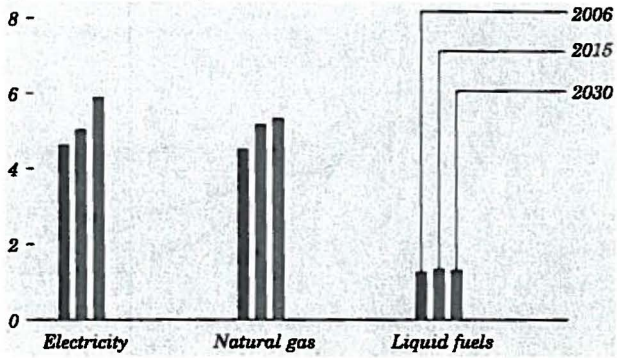


Residential energy use per person has remained fairly constant since 1990 (taking into account year-to-year fluctuations in weather), with increases in energy efficiency offset by consumer preference for larger homes and by new residential uses for energy. Over the past 10 years, the weather has generally been warmer than the 30-year average, causing energy use per person to remain mostly below its 1990 level. Given the preponderance of warmer winters and summers, the *AEO2008* projections define normal weather as the average of the most recent 10 years of historical data, which decreases the need for heating fuels, such as natural gas and fuel oil, and increases the need for electricity used for air conditioning, all else being equal [*79*].

In the *AEO2008* projections, residential energy use per capita changes with assumptions about the rate at which more efficient technologies are adopted. The 2008 technology case assumes no increase in the efficiency of equipment or building shells beyond those available in 2008. The high technology case assumes lower costs, higher efficiencies, and earlier availability of some advanced equipment. In the reference case, residential energy use per capita is projected to fall below the 2006 level after 2024. The 2008 technology case approximates an upper bound on residential energy use per capita in the future: delivered energy use per capita in the residential sector remains above the 2006 level through 2030, when it is 7 percent higher than projected in the reference case (Figure 44). The high technology case provides a lower bound, falling below the 2006 level after 2016 and reaching a 2030 level that is 5 percent below the reference case projection.

Household Uses for Electricity Continue To Expand

Figure 45. Residential delivered energy consumption by fuel, 2006, 2015, and 2030 (quadrillion Btu)



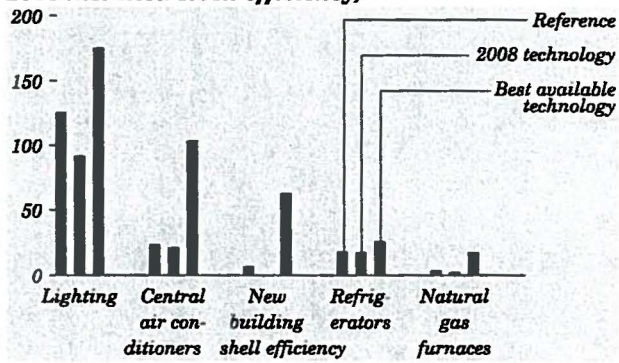
In 2006, households consumed more electricity than natural gas for the first time, as warmer winter temperatures reduced the need for natural gas heating. Over the past decade, residential electricity use has grown steadily, as a result of the increase in air conditioning use and the introduction of new applications. That trend is expected to continue in *AEO2008* (Figure 45). In 2030, electricity use for home cooling is 38 percent higher than the 2006 level in the reference case, as the U.S. population continues to migrate to the South and West, and older homes convert from room air conditioning to central air conditioning. A projected 25-percent increase in the number of households also increases the demand for appliances, and total electricity use in the residential sector increases by 27 percent from 2006 to 2030 in the reference case.

Natural gas and liquid fuels are used in the residential sector primarily for space and water heating. Few new uses have emerged over the past decade, and few are expected in the future. Thus, natural gas and liquids consumption per household decreases as the energy efficiency of furnaces and building components continues to improve.

The 2008 technology and high technology cases provide high and low ranges for the projections. In the high technology case, for example, high-efficiency air conditioners and condensing gas furnaces become more prevalent. Recent developments in solid-state lighting technologies, such as light-emitting diodes (LEDs), are reflected in the reference case as a reduction of up to 85 percent in the amount of electricity needed to provide a given amount of useful light.

Increases in Energy Efficiency Are Projected To Continue

Figure 46. Efficiency gains for selected residential appliances, 2030 (percent change from 2006 installed stock efficiency)



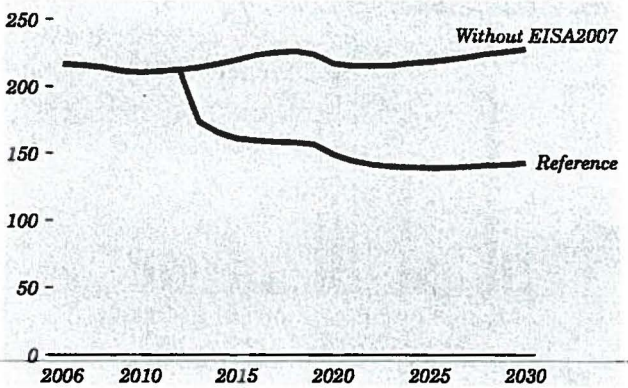
The energy efficiency of new household appliances plays a key role in determining the types and amounts of energy used in residential buildings. As a result of stock turnover and purchases of more efficient equipment, energy use by residential consumers, both per household and per capita, has fallen over time. In the 2008 technology case, which assumes no efficiency improvement of available appliances beyond 2008 levels, normal stock turnover results in higher average energy efficiency for most end uses in 2030, as older appliances are replaced with more efficient models from the existing stock of appliances (Figure 46).

The largest gains in residential energy efficiency are projected in the best available technology case, which assumes that consumers purchase the most efficient products available at normal replacement intervals regardless of cost, and that new buildings are built to the most energy-efficient specifications available, starting in 2009. In this case, residential delivered energy consumption in 2030 is 27 percent less than in the 2008 technology case and 22 percent less than in the reference case. Purchases of new energy-efficient products, especially compact fluorescent and solid-state lighting and condensing gas furnaces, reduce energy use without lowering service levels.

Several current Federal programs, including Zero Energy Homes and ENERGY STAR Homes, promote the use of efficient appliances and building envelope components, such as windows and insulation. In the best available technology case, use of the most efficient building envelope components available can reduce heating requirements in an average new home by more than 60 percent.

Residential Electricity Use for Lighting Is Expected To Decline

Figure 47. Electricity consumption for residential lighting, 2006-2030 (billion kilowatthours per year)



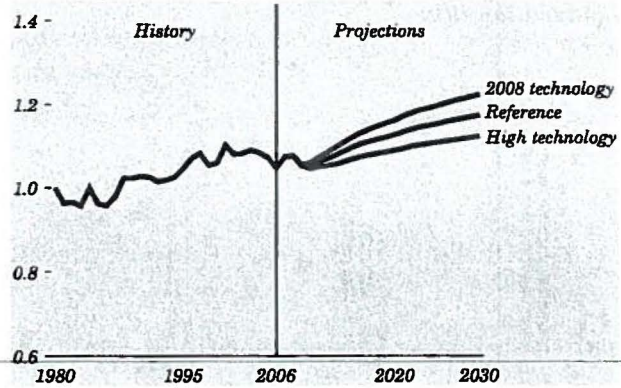
Residential electricity use for lighting accounted for about 16 percent of the sector's total electricity consumption in 2006, making it the second largest use for electricity in households. In the *AEO2008* reference case, electricity use for lighting declines as a result of the lighting efficiency standards in EISA2007, which require general-service incandescent light bulbs to reduce wattage by about 28 percent by 2014, increasing to 65 percent in 2020. DOE is required to examine the potential for tighter standards after 2020, but the details are uncertain and are not included in the *AEO2008* reference case.

Figure 47 summarizes residential lighting use in the *AEO2008* reference case and a case without EISA-2007. Given the relatively rapid turnover in incandescent lighting, EISA2007 achieves electricity savings immediately, reducing lighting demand by 27 percent (59 billion kilowatthours) in 2015. With continued tightening of the standard through 2020, demand for lighting is reduced by 85 billion kilowatthours in 2030, as efficient lighting options, mainly LEDs, gain market share.

In 2007, roughly 200 million compact fluorescent light (CFL) bulbs were sold in the United States, accounting for about 10 percent of total sales. Even without the new standards, CFL sales in the residential market were expected to continue growing in the coming years. LED lamps, which are just now being introduced in the general-service residential lighting market, reach nearly 20 percent of sales in 2020 without the EISA2007 standards. With the EISA2007 standards, the market share for LED bulbs in 2020 doubles.

Rise in Commercial Energy Use per Capita Is Projected To Continue

Figure 48. Commercial delivered energy consumption per capita, 1980-2030 (index, 1980 = 1)

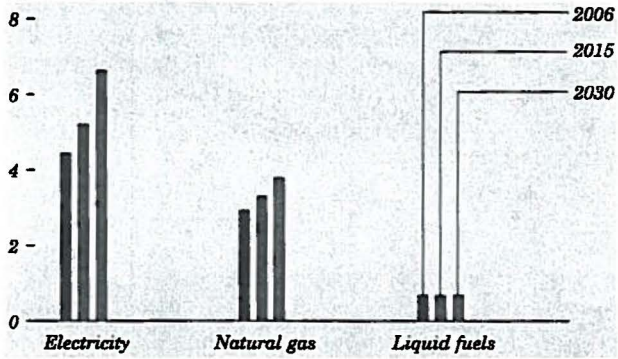


Assumptions about the availability and adoption of energy-efficient technologies define the range for delivered commercial energy use per person in the *AEO2008* projections. Commercial energy consumption per capita increases by a total of 12 percent from 2006 to 2030 in the reference case, primarily as a result of rising electricity use as the Nation continues to move to a service economy. The size of the projected increase varies from a low of 7 percent in the high technology case to a high of 17 percent in the 2008 technology case (Figure 48).

In terms of floorspace, growth in the commercial sector averages 1.2 percent per year from 2006 to 2030, driven by trends in economic and population growth. The reference case assumes future improvements in efficiency for commercial equipment and building shells, as well as increased demand for services. Consequently, commercial energy use increases at about the same rate as floorspace in the reference case, and commercial energy intensity (delivered energy consumption per square foot of floorspace) shows little change, increasing by less than 2 percent. The 2008 technology case assumes no increase in the energy efficiency of commercial equipment and building shells beyond those available in 2008. The result is a 4-percent increase in commercial delivered energy use in 2030 relative to the reference case. In the high technology case, assuming earlier availability, lower costs, and higher efficiencies for more advanced equipment and building shells, delivered energy consumption in 2030 is 4 percent below the reference case projection.

Electricity Leads Expected Growth in Commercial Energy Use

Figure 49. Commercial delivered energy consumption by fuel, 2006, 2015, and 2030 (quadrillion Btu)

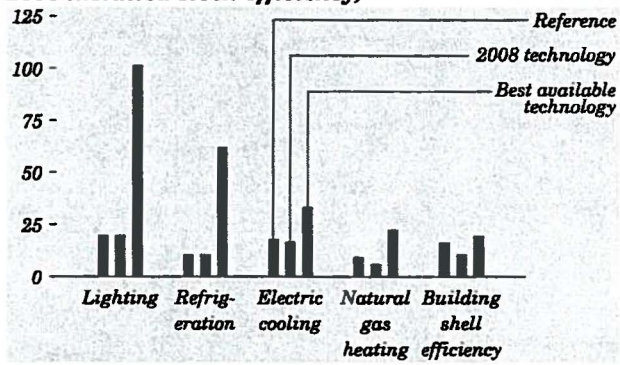


In the *AEO2008* projections, growth in disposable income leads to increased demand for services from hotels, restaurants, stores, theaters, galleries, arenas, and other commercial establishments, which in turn are increasingly dependent on computers and other electronic office equipment both for basic services and for business services and customer transactions. In addition, the growing share of the population over age 65 increases demand for health care and assisted-living facilities and for electricity to power medical and monitoring equipment at those facilities. The reference case projects increases in commercial electricity use averaging 1.7 percent per year from 2006 to 2030 (Figure 49). The high technology and 2008 technology cases provide low and high ranges for the average annual growth rate of commercial electricity consumption from 2006 to 2030, at 1.4 percent and 2.0 percent, respectively.

Use of natural gas and liquids for heating shows limited growth, as commercial activity reflects the U.S. population shift to the South and West and the efficiency of building and equipment stocks improves. Commercial natural gas use grows by 1.1 percent per year on average from 2006 to 2030 in the reference case, including more use of CHP in the later years. While there is little change in liquid fuel consumption, the projections for natural gas use in 2030 range from 3.8 quadrillion Btu in the reference case to 4.0 quadrillion Btu in the high growth case and 3.5 in the low growth case. The high and low oil price cases show the widest range for liquid fuels use, varying from 7 percent below to 12 percent above the reference case projection of 0.7 quadrillion Btu in 2030.

Technology Provides Potential Energy Savings in the Commercial Sector

Figure 50. Efficiency gains for selected commercial equipment, 2030 (percent change from 2006 installed stock efficiency)



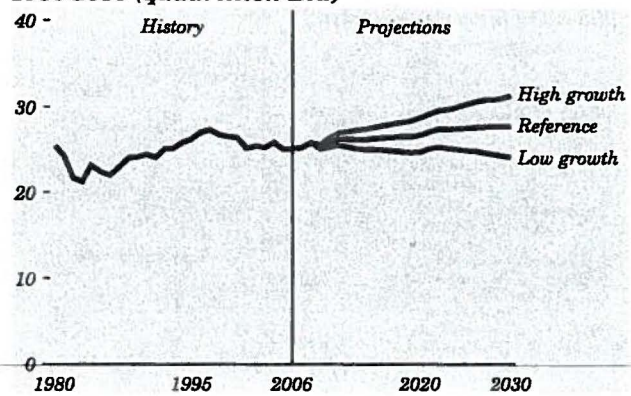
The stock efficiency of energy-using equipment in the commercial sector increases in the *AEO2008* reference case. Adoption of more energy-efficient equipment moderates the growth in demand, in part because of existing building codes for new construction and minimum efficiency standards, including those in EPACT2005 and EISA2007; however, the long service lives of many kinds of energy-using equipment limit the pace of efficiency improvements.

The most rapid increase in overall energy efficiency for the commercial sector occurs in the best available technology case, which assumes that only the most efficient technologies are chosen, regardless of cost, and that new building shells in 2030 are 19 percent more efficient than the commercial buildings stock in 2006. With the adoption of improved heat exchangers for space heating and cooling equipment, solid-state lighting, and more efficient compressors for commercial refrigeration, commercial delivered energy consumption in 2030 in the best technology case is 12 percent less than in the reference case and 16 percent less than in the 2008 technology case.

In the 2008 technology case, which assumes equipment and building shell efficiencies limited to those available in 2008, energy efficiency in the commercial sector still improves from 2006 to 2030 (Figure 50), because the technologies available in 2008 can provide savings relative to equipment currently in place. When businesses consider equipment purchases, however, the additional capital investment needed to buy the most efficient technologies often carries more weight than do future energy savings.

Economic Growth Cases Show Range for Projected Industrial Energy Use

Figure 51. Industrial delivered energy consumption, 1980-2030 (quadrillion Btu)

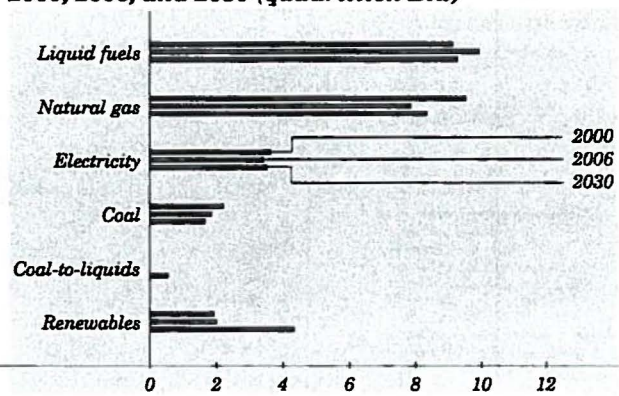


In the *AEO2008* reference case, industrial value of shipments grows at an annual rate of 1.3 percent from 2006 to 2030. Industrial delivered energy consumption increases by just 0.4 percent per year, from 25.1 quadrillion Btu in 2006 to 27.7 quadrillion Btu in 2030, as increased efficiency and changes in the composition of output partially offset growth. In the low economic growth case, industrial value of shipments grows by 0.5 percent per year, and delivered energy consumption falls to 24.2 quadrillion Btu in 2030. In the high growth case, industrial value of shipments grows by 2.0 percent per year, and energy consumption rises to 31.7 quadrillion Btu in 2030, 14 percent higher than in the reference case (Figure 51). The variation in industrial output growth among the three cases is well within the typical range over the past 16 years, when output grew by 1.7 percent per year on average from 1990 to 2007, and annual growth rates ranged from 5.7 percent to a decline of 4.7 percent.

The construction and chemical industries were particularly affected by the recent economic slowdown, and their future growth is expected to be modest (averaging 0.5 percent per year for the construction industry from 2006 to 2030 in the reference case). As a result, energy consumption in the construction sector declines from 2.4 quadrillion Btu in 2006 to 2.2 quadrillion Btu in 2030, with about 70 percent of the decrease attributed to reduced use of asphalt. The bulk chemical industry shows little growth from 2006 to 2030, and its fuel consumption for energy and feedstock totals only 5.6 quadrillion Btu in 2030, as compared with an estimated 6.8 quadrillion Btu in 2006.

Industrial Fuel Choices Vary Over Time

Figure 52. Industrial energy consumption by fuel, 2000, 2006, and 2030 (quadrillion Btu)

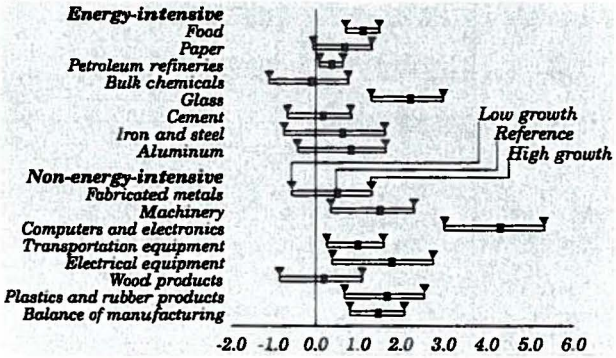


Industries adjust their fuel and product mixes over time to respond to changing markets, as indicated by the falling share of industrial coal use for process steam and the rapid increase in coal use for production of liquid fuels in the *AEO2008* reference case (Figure 52). Traditional coal use falls slightly as the use of metallurgical coal in steelmaking declines, reflecting the difficulty of building additional coke ovens in the United States. Industrial demand for steam coal as a boiler fuel also declines, as industrial processes become more efficient and use less steam, and as the growth of energy- and steam-intensive industries slows. As a result, consumption of steam coal in the industrial sector declines by 0.3 percent per year in the reference case projection.

Natural gas consumption, excluding lease and plant use, increases from 6.7 quadrillion Btu in 2006 to 7.1 quadrillion Btu in 2030—only slightly less than in 1990 (7.2 quadrillion Btu). Consumption of liquid fuels falls slightly, from 9.9 quadrillion Btu in 2006 to 9.3 quadrillion Btu in 2030, but remains the largest category of industrial energy consumption. About three-quarters of industrial liquids consumption is for nonfuel uses or as a byproduct in the refining industry. Industrial consumption of purchased electricity grows by just 0.1 percent per year. The only industrial fuels for which significant increases are projected are coal used in CTL plants and biofuel for ethanol production. From no commercial production in 2006, coal use for CTL grows to 0.6 quadrillion Btu in 2030 in the reference case, and biofuel use for ethanol production increases eightfold, to 2.3 quadrillion Btu in 2030.

Energy-Intensive Industries Grow Less Rapidly Than Industrial Average

Figure 53. Average growth in value of shipments for the manufacturing subsectors, 2006-2030 (percent per year)



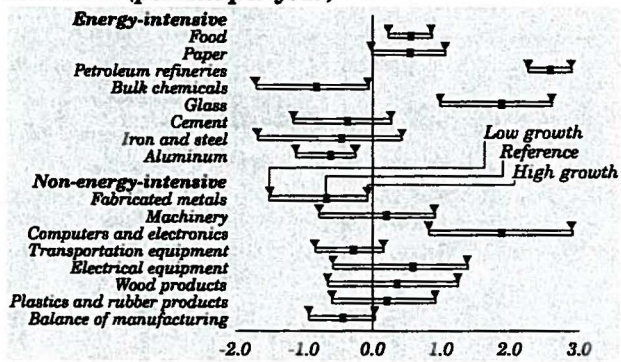
In the *AEO2008* reference case, average annual growth in value of shipments for the manufacturing sectors ranges from a decline of 0.1 percent per year (bulk chemicals) to an increase of 4.3 percent per year (computers). The pattern is similar in the economic growth cases (Figure 53).

For the bulk chemical industry, value of shipments grows slowly for several years and then falls slightly over the last decade of the projection, as export demand falls and other countries increase production. The annual rate of growth in the energy-intensive manufacturing group (0.7 percent) is lower than in the non-energy-intensive group (1.9 percent). Glass is the only energy-intensive subsector with a growth rate above 2 percent per year in the reference case. The growth rate for the industrial sector as a whole in the final 10 years of the projection is slightly lower than in the earlier years (1.2 percent compared with 1.4 percent). Growth rates for the individual subsectors vary considerably, with about one-quarter of them growing more rapidly in the final decade.

The projected growth rates for value of shipments in the industrial subsectors in the high and low economic growth cases generally are symmetrical around the reference case. Industries with the most rapid projected growth in the reference case also have relatively more rapid growth in the high and low economic growth cases. The range across economic growth cases and subsectors is substantial, from a decline of 1.1 percent per year for bulk chemicals in the low economic growth case to an increase of 5.3 percent per year for computer manufacturing in the high economic growth case.

Energy Consumption Growth Varies Widely Across Industry Sectors

Figure 54. Average growth of delivered energy consumption in the manufacturing subsectors, 2006-2030 (percent per year)

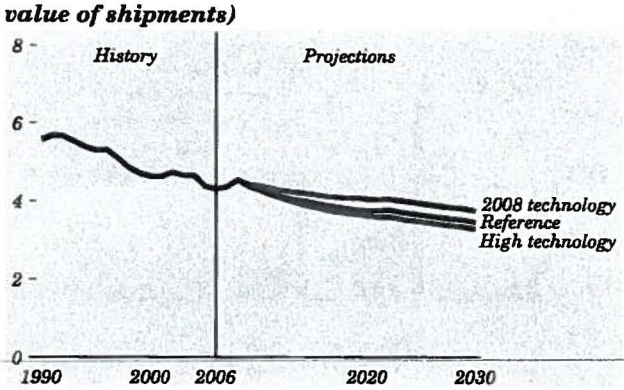


The range of projections for industrial energy consumption in *AEO2008* largely reflects uncertainty about the rate of economic growth. Average annual growth in total delivered energy consumption in the industrial sector from 2006 to 2030 ranges from a decline of 0.1 percent in the low economic growth case to an increase of 1.0 percent in the high economic growth case. In 2030, consumption is 3.5 quadrillion Btu lower in the low economic growth case and 4.0 quadrillion Btu higher in the high economic growth case when compared with the reference case. Thus, across the cases, the range for industrial energy consumption in 2030 is 7.5 quadrillion Btu.

In the reference case, energy consumption growth varies substantially among industry subsectors (Figure 54). Delivered energy consumption falls over the projection period for one-half of the energy-intensive industries (bulk chemicals, cement, iron and steel, and aluminum) as a result of relatively slow output growth rates, combined with expected changes in production technology over the projection period. The declines are reinforced by modest increases in energy prices after 2020. In general, the subsectors with the highest growth rates in energy consumption are those with the highest growth rates in value of shipments (computers and glass). The petroleum refining sector is an exception. As refineries shift to alternative feedstocks for liquids production (biofuels, coal, heavier crude oil), more energy is required per unit of output than is used for traditional petroleum-based refining. Energy consumption at refineries increases from 3.9 quadrillion Btu in 2006 to 7.3 quadrillion Btu in 2030—more than the total growth in industrial sector energy consumption.

Energy Intensity in the Industrial Sector Continues To Decline

Figure 55. Industrial delivered energy intensity, 1990-2030 (thousand Btu per 2000 dollar value of shipments)



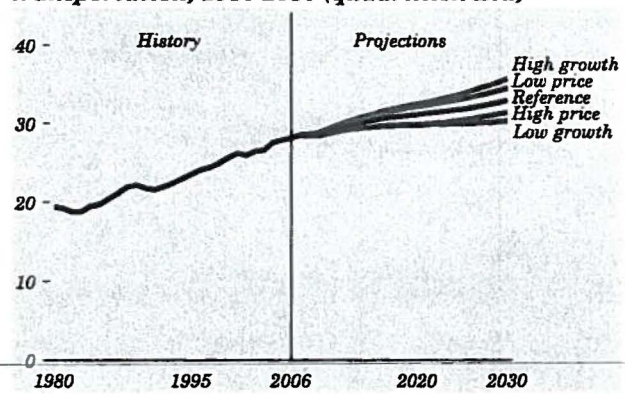
From 1990 to 2006, energy consumption in the industrial sector increased by only 0.5 quadrillion Btu (3 percent), while the value of shipments increased by 33 percent. Thus, industrial delivered energy use per dollar of industrial value of shipments declined by an average of 1.6 percent per year from 1990 to 2006 (Figure 55). Factors contributing to the drop in energy intensity include continued restructuring that reduced the industrial sector share of the most energy-intensive industries; higher petroleum and natural gas prices since 1998, which stimulated greater improvements in energy efficiency; and hurricane-related shutdowns in 2005.

The energy-intensive industries' share of industrial output fell from 23 percent in 1990 to 21 percent in 2006; and in 2030 their share is projected to be 18 percent. Consequently, even if no specific industry showed a reduction in energy intensity, the aggregate energy intensity of the industrial sector would decline. The shift in output share to less energy-intensive industries accounts for 84 percent of the projected change in industrial energy intensity in the reference case [*80*].

The technology cases represent alternative views of the evolution and adoption of energy-saving technologies in the industrial sector. In the high technology case, industrial energy intensity falls by 1.1 percent per year, compared with 0.9 percent per year in the reference case. In the 2008 technology case, energy intensity improves by only 0.5 percent per year. Across the technology cases, industrial energy consumption in 2030 varies over a range from 26.5 to 30.3 quadrillion Btu.

Growth in Transportation Energy Use Is Expected To Slow

Figure 56. Delivered energy consumption for transportation, 1980-2030 (quadrillion Btu)



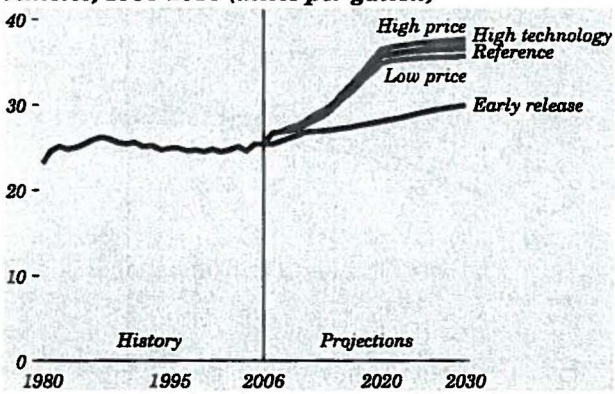
Delivered energy consumption in the transportation sector grows at an average annual rate of 0.7 percent in the *AEO2008* reference case, from 28.2 quadrillion Btu in 2006 to 33.0 quadrillion Btu in 2030 (Figure 56). That rate is less than the historical rate of 1.4 percent per year from 1980 to 2006, because the new EISA2007 fuel economy standards, slower economic growth, and higher fuel prices lead to efficiency improvements and slower growth in travel demand.

Transportation energy consumption is influenced by a variety of factors, including economic growth, population growth, fuel prices, and vehicle fuel efficiency. *AEO2008* includes cases that examine the impacts of those factors on delivered energy consumption. In 2030, transportation sector energy consumption is about 8 percent higher in the high economic growth case and 8 percent lower in the low economic growth case than in the reference case, and it is about 5 percent lower in the high price case and 5 percent higher in the low price case than in the reference case.

By mode, the largest share of total transportation energy consumption is for travel by LDVs (cars, pickup trucks, sport utility vehicles, and vans). The modes with the largest increases in energy demand are heavy trucks (medium and large—classes 3 through 8—freight trucks and buses) and aircraft. Heavy vehicles, which accounted for 18 percent of the sector's total energy use in 2006, account for 20 percent in 2030 in the reference case. With expected strong growth in demand for air travel and more investment in infrastructure, air travel also accounts for a growing portion of total energy consumption (13 percent in 2030, up from 9 percent in 2006).

EISA2007 Improves Fuel Economy of Light-Duty Vehicles

Figure 57. Average fuel economy of new light-duty vehicles, 1980-2030 (miles per gallon)



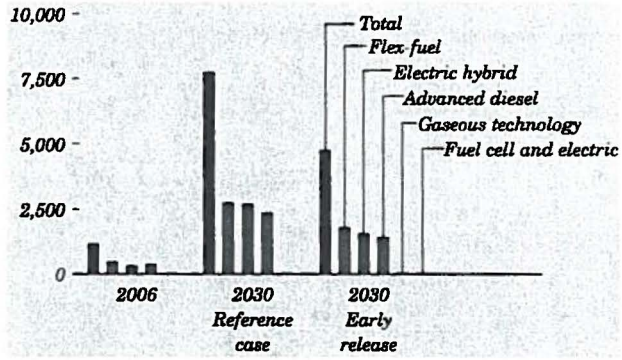
Light trucks have made up a steadily growing share of U.S. LDV sales in recent years, accounting for more than 50 percent of all new LDVs in 2006, compared with 21 percent in 1980 [*81*]. Consequently, despite fuel economy improvements, the average fuel economy of new LDVs declined from a 1987 peak of 26.2 mpg to a low of 25.4 mpg in 2005 and remained at roughly that level in 2006 (Figure 57).

EISA2007, enacted in December 2007, sets a new CAFE standard of 35 mpg for LDVs in 2020. Without EISA2007 (in the early release case), some advanced vehicle technologies are adopted, and the average fuel economy for new LDVs increases to 30.0 mpg in 2030. In the *AEO2008* reference case, with the EISA2007 provisions included, the fuel economy of new LDVs increases to 36.6 mpg in 2030.

The economics of fuel-saving technologies improve further in the high technology and high price cases, and consumers buy more fuel-efficient cars and trucks. In both cases, however, average fuel economy improves only modestly from the reference case level, because meeting the CAFE standards in EISA2007 already requires significant penetration of advanced technologies, pushing fuel economy improvements to the limit of current economic feasibility. In the low price case there is little or no economic incentive for consumers to purchase more fuel-efficient vehicles, and LDV fuel economy in 2030 is slightly lower than in the reference case.

Unconventional Vehicle Technologies Exceed 25 Percent of Sales in 2030

Figure 58. Sales of unconventional light-duty vehicles by fuel type, 2006 and 2030 (thousand vehicles sold)



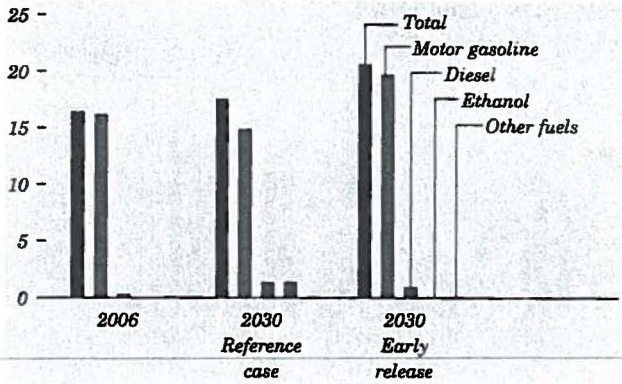
Concerns about oil supply, fuel prices, and emissions have driven the development and market penetration of unconventional vehicles (which can use alternative fuels, electric motors and advanced electricity storage, advanced engine controls, or other new technologies). Unconventional technologies are expected to play an even greater role in meeting the LDV CAFE standards in EISA2007. In the reference case (with EISA2007), unconventional vehicle sales total 7.7 million units (42 percent of new LDV sales) in 2030. Without EISA2007, only 4.7 million units are sold in 2030, making up 25 percent of total new LDV sales (Figure 58).

Sales of hybrid vehicles grow to 2.7 million units in 2030 in the reference case, compared with 1.6 million units without EISA2007. Light-duty diesel engines with advanced direct injection, which can significantly reduce exhaust emissions and improve efficiency, capture 13 percent of the market for new LDVs in 2030. The availability of ultra-low-sulfur diesel (ULSD) and biodiesel fuels, along with advances in emission control technologies that reduce criteria pollutants, increase the sales of unconventional diesel vehicles.

Currently, manufacturers have an incentive to sell flex-fuel vehicles (FFVs), because they receive fuel economy credits that count toward CAFE compliance. Although the credits are phased out by 2020 under EISA2007, FFV sales increase from 454,600 units in 2006 to 2.7 million units in 2030 in the reference case as a result of the growing use of E85 that is needed to satisfy the EISA2007 RFS.

EISA2007 Reduces Light-Duty Vehicle Fuel Use by 3 Quadrillion Btu in 2030

Figure 59. Energy use for light-duty vehicles by fuel type, 2006 and 2030 (quadrillion Btu)



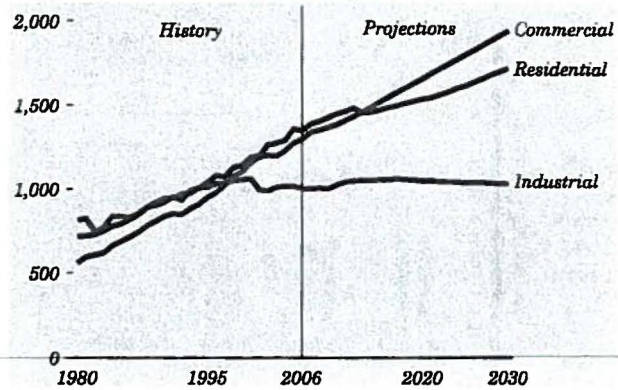
In the reference case, EISA2007 reduces energy consumption for LDVs by more than 3 quadrillion Btu in 2030, from 20.6 quadrillion Btu without EISA2007 to 17.5 quadrillion Btu with the bill (Figure 59). Although total vehicle sales are approximately the same in 2030 with and without EISA2007, higher CAFE standards lead to the savings in energy consumption.

With EISA2007, LDV motor gasoline consumption drops by 4.9 quadrillion Btu in 2030, from 19.7 quadrillion Btu to 14.8 quadrillion Btu. Much of the decline results from switching to unconventional technologies. Diesel fuel consumption in 2030, including biodiesel and BTL diesel, is 1.3 quadrillion Btu, 0.4 quadrillion Btu higher than without EISA2007; and E85 consumption is 1.3 quadrillion Btu in 2030, up from almost zero without EISA2007. The amount of ethanol used in blending is about the same in both cases because of EPA restrictions on ethanol fuel blending.

As a result of EISA2007, the motor gasoline share of fuel use for new LDVs in 2030 declines, and the shares of diesel and ethanol increase. In the reference case, motor gasoline accounts for 84.7 percent of the total, down from 95.4 percent without EISA2007. The diesel fuel share increases to 7.5 percent of total consumption, and the ethanol share increases to 7.7 percent [*82*].

Residential and Commercial Sectors Dominate Electricity Demand Growth

Figure 60. Annual electricity sales by sector, 1980-2030 (billion kilowatthours)

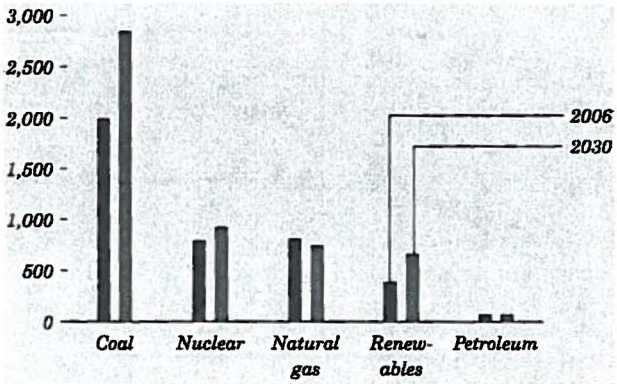


Total electricity sales increase by 29 percent in the *AEO2008* reference case, from 3,659 billion kilowatthours in 2006 to 4,705 billion in 2030, at an average rate of 1.1 percent per year. The relatively slow growth follows the historical trend, with the growth rate slowing in each succeeding decade. Electricity sales, which are strongly affected by economic growth, increase by 39 percent in the high growth case, to 5,089 billion kilowatthours in 2030, but by only 18 percent in the low growth case, to 4,319 billion kilowatthours in 2030. In the reference case, the largest increase is in the commercial sector, at 49 percent from 2006 to 2030 (Figure 60), as service industries continue to drive growth. Electricity demand grows by 27 percent in the residential sector and by only 3 percent in the industrial sector. Growth in population and disposable income leads to increased demand for products, services, and floorspace. Population shifts to warmer regions also increase the need for cooling.

Efficiency gains offset growth in electricity demand, as higher energy prices encourage investment in energy-efficient equipment. In both the residential and commercial sectors, continuing efficiency gains in electric heat pumps, air conditioners, refrigerators, lighting (notably LED lighting), cooking appliances, and computer screens slow the growth of electricity demand. The new standards set in EISA2007 for lighting and other appliances (such as boilers, dehumidifiers, dishwashers, and clothes washers) further dampen electricity demand throughout the projection. Slow growth in industrial production, particularly in the energy-intensive industries, limits electricity demand growth in the industrial sector.

Coal-Fired Power Plants Provide Largest Share of Electricity Supply

Figure 61. Electricity generation by fuel, 2006 and 2030 (billion kilowatthours)



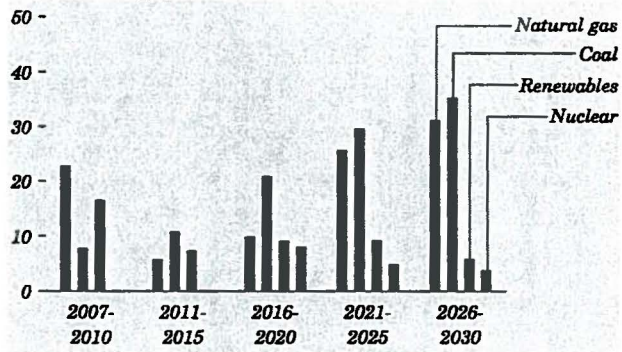
Coal-fired power plants (including utilities, independent power producers, and end-use CHP) continue to be the dominant source of electricity generation through 2030 (Figure 61). Although natural-gas-fired plants with lower capital costs make up most of the capacity additions over the next 10 years, more coal-fired plants are built in the later years as natural gas fuel costs increase. The natural gas share of generation falls from 20 percent in 2006 to 14 percent in 2030, while the coal share increases from 49 percent to 54 percent.

Federal tax incentives, State renewable energy programs, and rising fossil fuel prices lead to increases in renewable and nuclear capacity and generation, as new plants are built. The generation share from renewable capacity increases by 32 percent from 2006 to 2030 and represents 13 percent of total electricity supply in 2030. With capacity additions and improvements in performance at existing nuclear facilities, nuclear generation also increases; however, the nuclear share of total generation falls slightly, from 19 percent in 2006 to 18 percent in 2030.

Technology choices for new plants and utilization of existing capacity are affected by relative fuel costs and changes in environmental policies. For example, natural-gas-fired plants are projected to supply 21 percent of total electricity supply in 2030 in the low price case but only 10 percent in the high price case, but coal-fired plants supply 49 percent of the total in the low price case and 57 percent in the high price case. Changes in environmental policies could also have a significant effect on the fuel shares of total generation.

Early Capacity Additions Use Natural Gas, Coal Plants Are Added Later

Figure 62. Electricity generation capacity additions by fuel type, including combined heat and power, 2007-2030 (gigawatts)



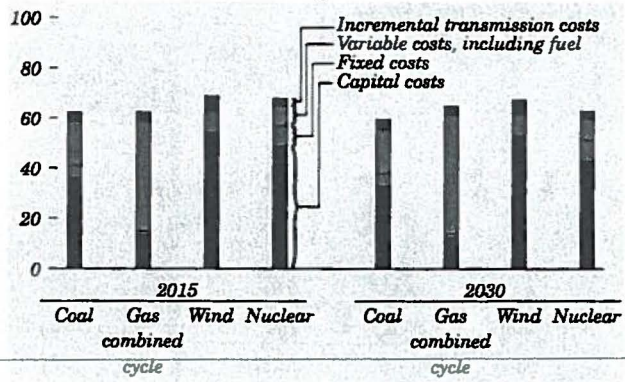
Decisions to add capacity and the choice of fuel type depend on electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for some technologies. With growing electricity demand and the retirement of 45 gigawatts of capacity, 263 gigawatts of new generating capacity (including end-use CHP) will be needed by 2030.

Natural-gas-fired plants generally have lower capacity costs but higher fuel costs than coal-fired plants. As a result, coal-fired plants typically are more economical, and they account for 40 percent of total capacity additions from 2006 to 2030, compared with a 36-percent share for natural gas (Figure 62). Renewable and nuclear plants tend to have high investment costs and relatively low operating costs. EPACT2005 and State RPS programs are expected to stimulate generation from renewable and nuclear plants, which represent 18 percent and 6 percent of total additions, respectively.

The quantity and mix of capacity additions can also be affected by different fuel price paths or growth rates for electricity demand. Because fuel costs are a larger share of total expenditures for new natural-gas-fired capacity, the higher fuel costs in the high price case lead to more coal-fired additions. In the economic growth cases, capacity additions range from 182 gigawatts in the low growth case to 349 gigawatts in the high growth case, although the generation shares for different technologies are similar in the two cases.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 63. Levelized electricity costs for new plants, 2015 and 2030 (2006 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 63) [*83*]. The *AEO2008* reference case assumes a capital recovery period of 20 years, with the cost of capital based on competitive market rates.

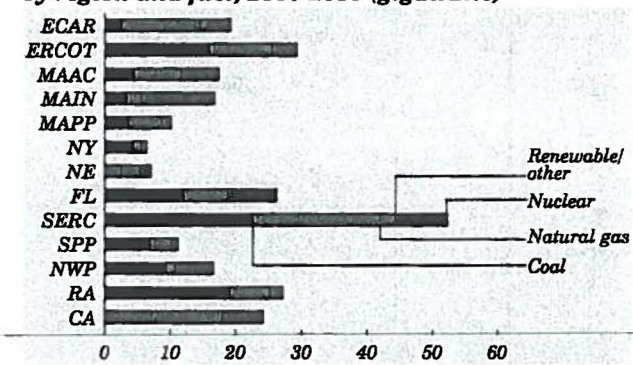
Real capital costs decline over time (Table 6) at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a progressively slower rate as more units are built. The efficiency of new plants is also assumed to improve through 2025, with heat rates for advanced combined cycle and coal gasification units declining from 6,752 and 8,765 Btu per kilowatthour in 2006 to 6,333 and 7,450 Btu per kilowatthour, respectively, in 2025.

Table 6. Costs of producing electricity from new plants, 2015 and 2030

Costs	2015		2030	
	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	2006 mills per kilowatthour			
Capital	35.83	13.44	32.91	12.50
Fixed	5.05	1.49	5.05	1.49
Variable	17.93	43.87	17.94	47.41
Incremental transmission	3.50	3.62	3.54	3.54
Total	**62.31**	**62.42**	**59.44**	**64.94**

Largest Capacity Additions Expected in the Southeast and the West

Figure 64. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2007-2030 (gigawatts)



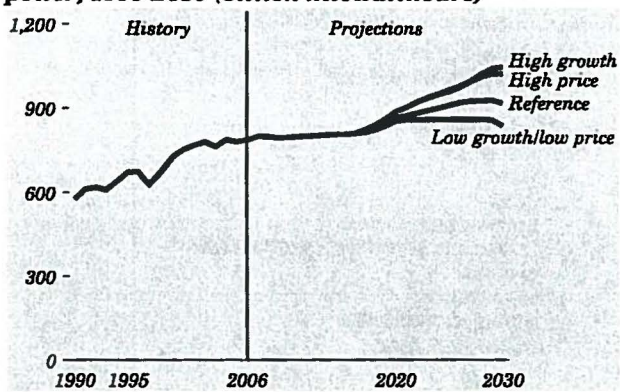
Most areas of the United States currently have excess generation capacity, but all electricity demand regions (see Appendix F for definitions) are expected to need additional, currently unplanned, capacity by 2030. The largest amount of new capacity is expected in the Southeast (FL and SERC), which represents a relatively large and growing share of total U.S. electricity sales and thus requires more capacity than other regions (Figure 64). The growth in demand for electricity in the Southeast is well above the national average.

With natural gas prices rising in the reference case, coal-fired plants account for the largest share of capacity additions through 2030, given the assumption that current environmental policies are maintained indefinitely. The largest concentration of new coal-fired capacity is in the Southeast, where new coal-fired plants are built to accommodate growth in the electricity market and the corresponding need for additional capacity.

Natural gas, renewable, and nuclear plants represent the remaining capacity additions. Natural-gas-fired plants are built to maintain a diverse capacity mix, to serve as reserve capacity, or to meet environmental regulations. About three-fourths of the additions are located in the Southeast, the West (NWP, RA, and CA), and the Midwest (ECAR, MAIN, and MAPP). Renewable capacity is also needed because of State and Federal renewable energy policies, and the Midwest accounts for the largest share of renewable capacity additions. Most nuclear additions are expected in the Southeast, where suppliers have expressed interest in building new nuclear plants.

EPACT2005 Tax Credits Are Expected To Stimulate New Nuclear Builds

Figure 65. Electricity generation from nuclear power, 1990-2030 (billion kilowatthours)

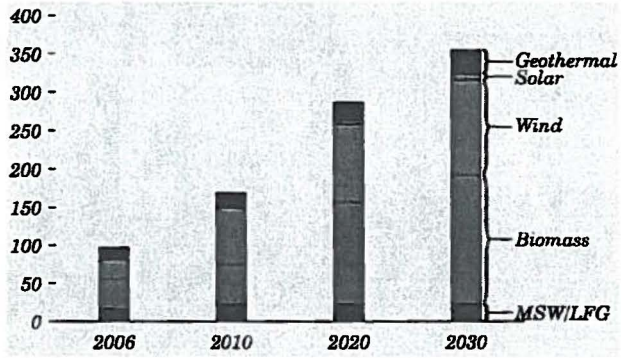


In the *AEO2008* reference case, nuclear capacity grows from 100.2 gigawatts in 2006 to 114.9 gigawatts in 2030, including 2.7 gigawatts of expansion at existing plants, 16.6 gigawatts of new capacity, and 4.5 gigawatts of retirements. EPACT2005 provides an 8-year PTC of 1.8 cents per kilowatthour for up to 6 gigawatts of new nuclear capacity built before 2021. The credit also can be shared for additional capacity but at a lower credit value. The reference case projects 8.0 gigawatts of new nuclear capacity (which will receive the tax credits) by 2020. Early builds are expected to bring down the cost of nuclear capacity and, when combined with rising fossil fuel costs, to result in additional nuclear builds after 2020. All uprates approved, pending, or expected by the NRC at existing units are assumed to be carried out. Most existing nuclear units are expected to continue operating through 2030, based on the assumption that they will apply for and receive license renewals. Seven units, totaling 4.5 gigawatts, are projected to be retired after 2028, when the end date of their original licenses plus a 20-year renewal is reached.

Projected nuclear capacity additions vary, depending on overall demand for electricity and the prices of other fuels. In the five main *AEO2008* cases, nuclear generation grows from 787 billion kilowatthours in 2006 to between 837 and 1,047 billion kilowatthours in 2030 (Figure 65). In the low price case, the delivered price of natural gas in 2030 is 15 percent lower than in the reference case, and new nuclear plants become less economical. In the high price and high growth cases, respectively, 30 and 33 gigawatts of new nuclear capacity are projected, because more capacity is needed and the cost of alternatives is higher.

Biomass and Wind Lead Projected Growth in Renewable Generation

Figure 66. Nonhydroelectric renewable electricity generation by energy source, 2006-2030 (billion kilowatthours)

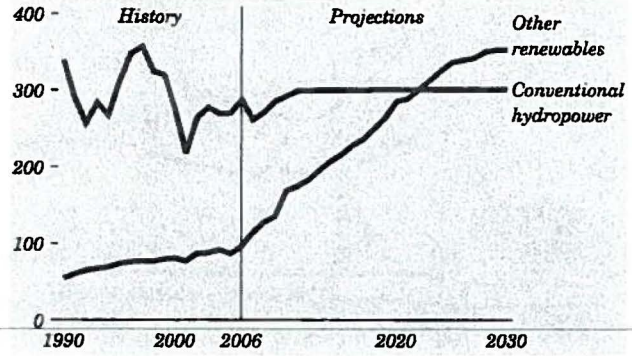


There is considerable uncertainty about the growth potential of wind power, which depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of the Federal PTC, which is expected to expire at the end of 2008. In the *AEO2008* reference case, generation from wind power increases from 0.6 percent of total generation in 2006 to 2.4 percent in 2030 (Figure 66). Biomass, both dedicated and co-firing, grows from 39 billion kilowatthours in 2006 (1.0 percent of the total) to 170 billion kilowatthours (3.2 percent). Generation from geothermal facilities also grows, but at a slower rate, increasing from 0.4 percent of total generation in 2006 to 0.6 percent in 2030. Current assessments show limited potential for expansion at conventional geothermal sites.

For consistency in reporting, nonbiogenic municipal solid waste (MSW) is separated from renewable generation. Nonrenewable materials, such as plastics, have made up an increasing proportion of MSW, and 44 percent of the energy value of MSW in 2005 was from nonbiogenic sources; in the *AEO2008* reference case, that share is held constant over the projection period. (All growth in generation from MSW and landfill gas facilities is attributed to landfill gas only.) Solar technologies in general remain too costly for grid-connected applications, but demonstration programs and State policies support some growth in central-station solar PV, and small-scale customer-sited PV applications grow rapidly [*84*].

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 67. Grid-connected electricity generation from renewable energy sources, 1990-2030 (billion kilowatthours)

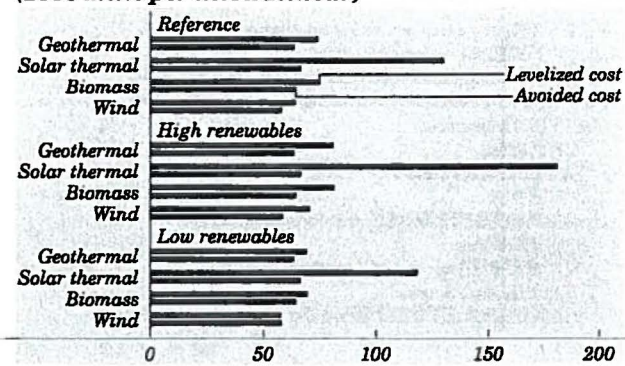


With State RPS programs included in the reference case, renewable electricity generation grows by more than 270 billion kilowatthours. In 2030, total renewable generation is 656 billion kilowatthours or 12.5 percent of total domestic power production. Although conventional hydropower remains the largest source of renewable generation through 2030 (Figure 67), environmental concerns and the scarcity of untapped large-scale sites limit its growth, and its share of total generation falls from 7.1 percent in 2006 to 5.8 percent in 2030. Electricity generation from nonhydroelectric alternative fuels increases, bolstered by legislatively mandated State RPS programs, technology advances and State and Federal supports, although the Federal PTC is assumed to expire at the end of 2008 per existing law. The share of nonhydropower renewable generation increases from 2.4 percent of total generation in 2006 to 6.8 percent in 2030.

Wind is the largest source of renewable generation among the nonhydropower renewable fuels, with 124 billion kilowatthours of generation in 2030, up from 26 billion kilowatthours in 2006. Initially helped by the Federal PTC, its growth continues as States meet their RPS requirements. Biomass also grows strongly, as generation from both dedicated facilities and co-firing applications increases to 83 billion kilowatthours in 2030, with an additional 87 billion kilowatthours generated in end-use systems. In the near term, market penetration by the unproven biomass gasification technology is slow, while co-firing expands more rapidly. The strong growth in end-use generation is led by the renewable fuels mandate. Facilities producing BTL fuels also use the feedstocks for electricity production.

Renewables Are Expected To Become More Competitive Over Time

Figure 68. Levelized and avoided costs for new renewable plants in the Northwest, 2030 (2006 mills per kilowatthour)

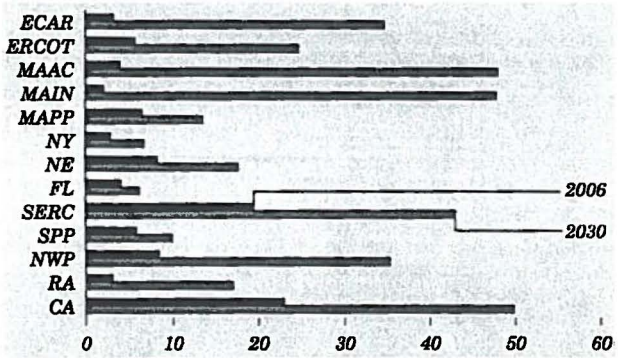


The projected cost of renewable generation in *AEO2008* is significantly higher than projected in previous *AEO*s, primarily as a result of increases in the installation cost of new generating capacity observed throughout the electric power industry. Broad indexes of utility construction costs suggest increases of approximately 15 percent over previous EIA estimates. Available data for specific renewable capacity markets, such as wind power, confirm both the direction and general magnitude of the cost increases when applied more narrowly to renewable generation. For *AEO2008*, the cost increases are applied to all power-sector installations, and they are expected to be persistent rather than short-term cost spikes. In general, renewable generation is expected to remain more expensive than the generation it would displace, that is, its avoided cost (Figure 68).

In addition to the increase in capital costs, EIA reassessed the cost and performance of dedicated biomass generation technology. According to an independent expert review, previous EIA estimates for biomass gasification technology understated its cost even before the industry-wide increase in capital costs. Although higher installation costs make biomass more expensive, significant growth in dedicated biomass capacity is expected in regions with stringent RPS requirements and limited supplies of lower cost resources, such as wind. In the near term, growth in renewable generation in those regions is met largely by biomass co-firing in existing coal plants—an option with relatively low capital costs. The higher efficiency of dedicated plants makes them increasingly attractive, however, as biomass fuels with higher energy value are used to meet RPS mandates.

State Portfolio Standards Increase Generation from Renewable Fuels

Figure 69. Regional growth in nonhydroelectric renewable electricity generation, 2006-2030 (billion kilowatthours)

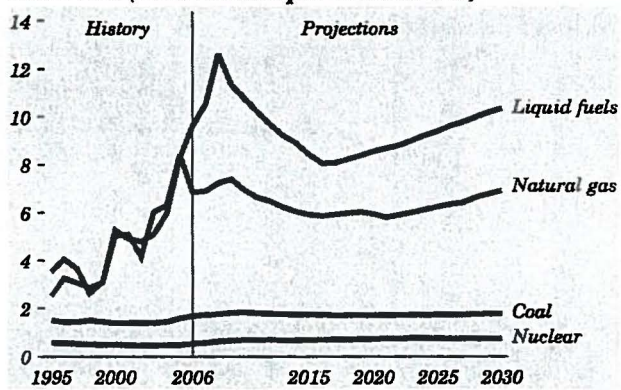


In October 2007, 25 States and the District of Columbia had legislatively mandated RPS programs. The mandatory programs were modeled in the *AEO2008* reference case [*85*], but States with voluntary goals were assumed not to have any impact on the national energy mix. Because NEMS does not provide projections at the State level, the reference case assumes that all States will reach their goals within each program's legislative framework, and the results are aggregated at the regional level. In some States, however, compliance could be limited by authorized funding levels for the programs. For example, California is not expected to meet its renewable energy targets because of limits to authorized funding for its RPS program.

In the reference case, wind capacity grows much more rapidly than projected in previous *AEO*s, to 40 gigawatts in 2030 [*86*]. Much of the qualifying capacity in the Midwest, Northeast, Southwest, and Pacific Northwest is expected to consist of wind farms. In one midwestern region (MAIN), 11 gigawatts of wind turbine capacity is projected to be on line in 2030, as compared with 220 megawatts in 2006. In the Mid-Atlantic region, State RPS programs are the driving force behind additional dedicated biomass gasification plants. Approximately 3 gigawatts of new capacity, along with co-firing, provides 37 billion kilowatthours of generation annually. Most of the new biomass capacity is projected to come on line in the Mid-Atlantic region from 2006 to 2030 (Figure 69). While the growth in wind capacity is the most dramatic, biomass co-firing and geothermal power plants also contribute to the baseload generation needed to satisfy State RPS requirements.

Fuel Costs Drop from Recent Highs, Then Increase Gradually

Figure 70. Fuel prices to electricity generators, 1995-2030 (2006 dollars per million Btu)



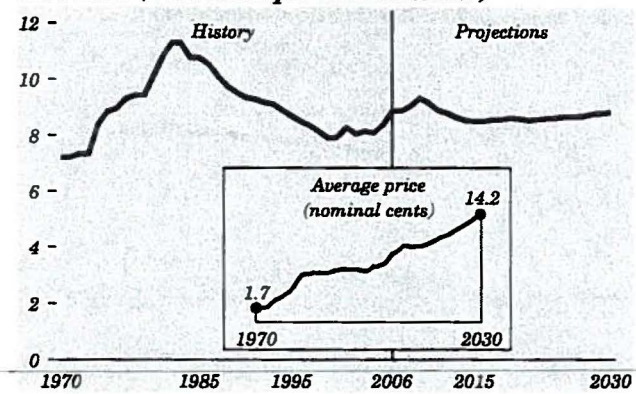
Fuel costs account for about two-thirds of the generating costs of new natural-gas-fired plants, less than one-third for new coal-fired plants, and less than one-tenth for new nuclear power plants in 2030. For many renewable fuels, such as wind and solar, fuel is free. Capital and operations and maintenance expenses make up the balance of the costs. As a result, natural-gas-fired generation tends to be the most sensitive—and wind and solar the least sensitive—to changes in fuel costs.

In the reference case, prices for fossil fuels delivered to electricity generators peak between 2005 and 2010, as the result of a boom in U.S. and foreign demand, combined with constraints on supply growth and political instability in oil- and gas-producing nations. Fossil fuel prices fall in the middle years of the projection, however, as new supplies come on line to meet growing demand. Prices then increase steadily as demand once again starts to outpace supply (Figure 70). Nuclear and biomass fuel prices rise gradually throughout the projection, as a result of worldwide growth in the demand for nuclear fuel and depletion of local biomass stocks.

Electricity generation from relatively low-cost, low-polluting, natural-gas-fired plants increased significantly in the early years of this decade. More recently, higher costs and increasing volatility of supply and prices have characterized natural gas markets. Consequently, in the reference case, the natural gas share of total electricity generation drops after 2016, and both coal-fired and renewable generation increase.

Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 71. Average U.S. retail electricity prices, 1970-2030 (2006 cents per kilowatthour)



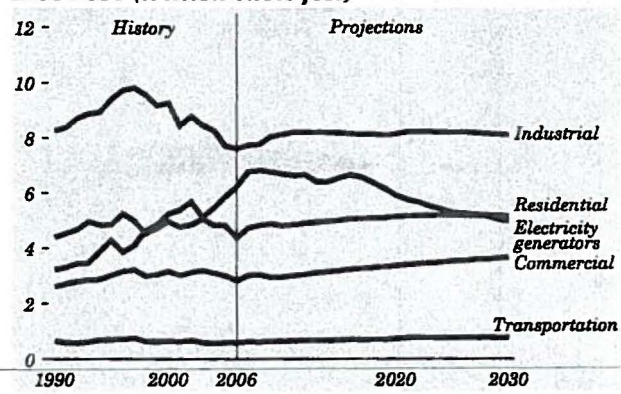
In the *AEO2008* reference case, continuing high fuel prices and escalating capital costs for new generating capacity lead to a jump in real electricity prices, peaking in 2009 at an annual average of 9.3 cents per kilowatthour (2006 dollars). Electricity prices fall to 8.5 cents per kilowatthour in 2015, as new sources of natural gas and coal are brought on line. From 2016 on, generally rising prices for natural gas and petroleum (in addition to the impact of State renewable fuel mandates) encourage power producers to increase their use of less expensive coal and renewable fuels. Retail electricity prices rise gradually after 2016, to 8.8 cents per kilowatthour in 2030 (Figure 71).

Customers in States with competitive retail markets for electricity experience the effects of changes in natural gas prices more rapidly than customers in States with regulated markets, because competitive prices are determined by the marginal cost of energy, and natural-gas-fired plants, with their higher operating costs, often set hourly marginal prices. After 2016, as other plant types set hourly prices more often, the price of natural gas has less influence on competitive retail markets. In the low and high oil and natural gas price cases, electricity prices range from 8.5 to 9.1 cents per kilowatthour in 2030.

Electricity distribution costs decline by 5 percent from 2006 to 2030, as technology improvements and a growing customer base lower the cost of the distribution infrastructure. Transmission costs increase by 30 percent, as additional investments are made in the grid to alleviate current constraints, facilitate competitive markets, and meet growing consumer demand for electricity.

Fastest Increase in Natural Gas Use Is Expected for the Buildings Sectors

Figure 72. Natural gas consumption by sector, 1990-2030 (trillion cubic feet)



In the reference case, total natural gas consumption increases from 21.7 trillion cubic feet in 2006 to a peak value of 23.8 trillion cubic feet in 2016, followed by a decline to 22.7 trillion cubic feet in 2030. The natural gas share of total energy consumption drops from 22 percent in 2006 to 20 percent in 2030.

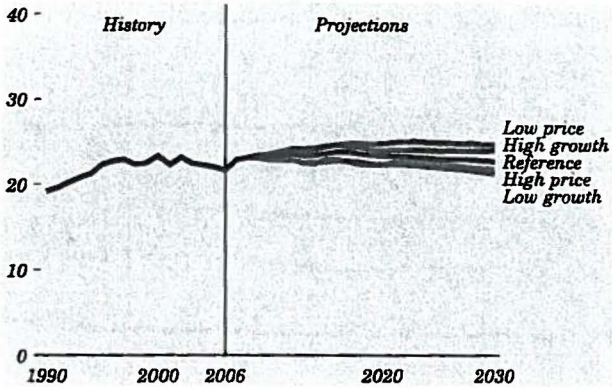
The projected path of total natural gas consumption depends almost entirely on the amount consumed in the electric power sector. Natural gas consumption for electricity generation in the power sector declines from current levels to 5.0 trillion cubic feet in 2030 in the reference case (Figure 72), as a result of a projected increase in natural gas prices that begins after 2016.

Natural gas consumption in the electric power sector is highly responsive to price changes, because electricity producers can choose among different fuels on an ongoing basis. In contrast, consumption of natural gas in the residential, commercial, and industrial sectors is influenced not only by fuel prices but also by economic trends. In those sectors, natural gas consumption increases steadily from 2006 through 2030.

In the industrial sector, natural gas consumption is projected to grow from 7.6 trillion cubic feet in 2006 to 8.1 trillion cubic feet in 2030. In the residential and commercial sectors (the buildings sectors), consumption increases from a combined total of 7.2 trillion cubic feet in 2006 to 8.8 trillion cubic feet in 2030. As a result, the buildings sectors show the greatest overall increase in natural gas consumption, in both percentage and absolute terms.

Natural Gas Consumption Varies With Fuel Prices and Economic Growth

Figure 73. Total natural gas consumption, 1990-2030 (trillion cubic feet)



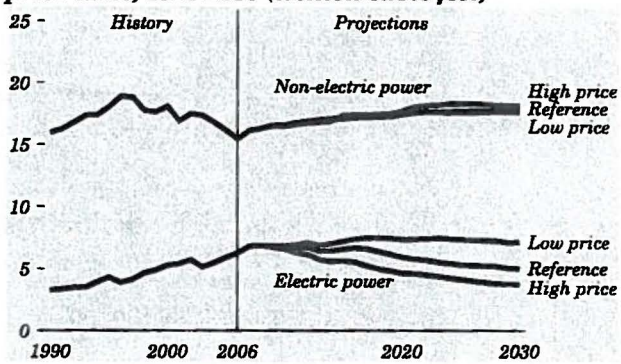
In the *AEO2008* projections, natural gas consumption varies with natural gas prices and economic growth rates. Higher natural gas prices reduce demand, and higher economic growth rates increase demand.

In the high and low price cases, natural gas consumption in 2030 ranges from 24.8 trillion cubic feet in the low case to 21.9 trillion cubic feet in the high case (Figure 73). High natural gas prices provide direct economic incentives for reducing natural gas consumption, whereas low prices encourage more consumption; however, the strength of the relationship depends on short- and long-term fuel substitution capabilities and equipment options within each consumption sector.

In the economic growth cases, consumption in 2030 varies from 24.0 trillion cubic feet in the high growth case to 21.3 trillion cubic feet in the low growth case. With faster economic growth, disposable income increases more rapidly, and consumers increase their energy purchases either by buying products that consume additional energy (such as larger homes), being less energy-efficient in using products they already own (for example, by setting thermostats higher in the winter and lower in the summer), or both.

Natural Gas Use in the Electric Power Sector Is Sensitive to Prices

Figure 74. Natural gas consumption in the electric power and non-electric power sectors in alternative price cases, 1990-2030 (trillion cubic feet)



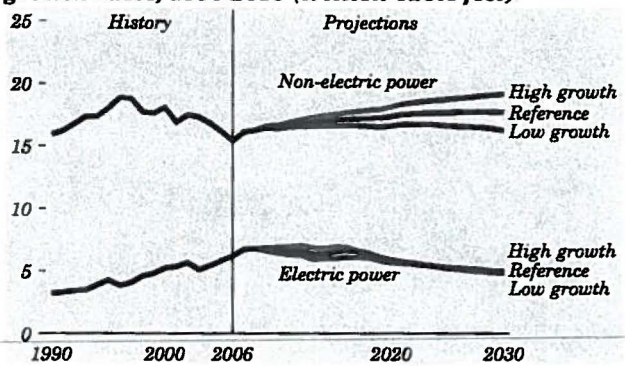
In the *AEO2008* projections, the largest variation in sectoral demand for natural gas in response to high and low price assumptions occurs in the electric power sector (Figure 74). Natural gas consumption by electricity producers in 2030, projected at 5.0 trillion cubic feet in the reference case, increases to 7.1 trillion cubic feet in the low price case but falls to 3.7 trillion cubic feet in the high price case.

Much of the variation in projected natural gas demand in the electric power sector between the low and high price cases is the result of different projections for the amount of natural-gas-fired generating capacity built—and consequently the amount of electricity generated from natural gas—from 2007 to 2030. In the high price case, a cumulative 65.4 gigawatts of new natural-gas-fired generating capacity is added in the electric power sector between 2007 and 2030. In the low price case, cumulative natural-gas-fired capacity additions in the electric power sector total 131.1 gigawatts over the same period.

When natural gas prices are high, electric power producers can quickly substitute generation from coal and other fuels for power generated from natural gas. In contrast, in the residential, commercial, industrial, and transportation sectors, fuel price assumptions have a considerably smaller effect on natural gas consumption, because fuel substitution options are limited and the stocks of equipment that use natural gas have relatively slow turnover rates. In 2030, total natural gas consumption in those sectors ranges from 18.1 trillion cubic feet in the high price case to 17.6 trillion cubic feet in the low price case.

Natural Gas Use in Other Sectors Is More Sensitive to Economic Growth

Figure 75. Natural gas consumption in the electric power and non-electric power sectors in alternative growth cases, 1990-2030 (trillion cubic feet)

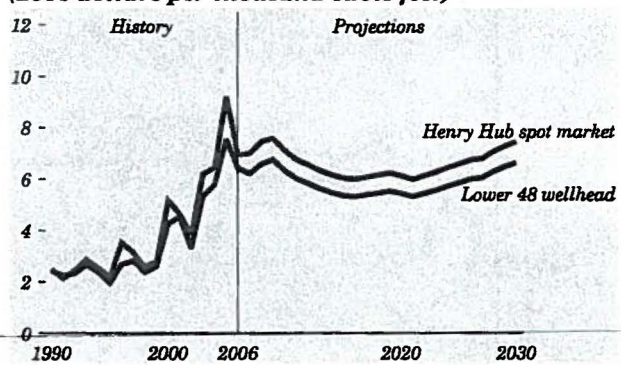


The largest variation in natural gas consumption in the residential, commercial, industrial, and transportation end-use sectors results from different assumptions about economic growth rates. In the high economic growth case, natural gas consumption in those end-use sectors is projected to total 19.2 trillion cubic feet in 2030. In the low growth case, the projected total in 2030 is 16.2 trillion cubic feet (Figure 75). Most of the difference between the projections in the two cases is attributable to the industrial sector, where growth in economic output has a greater impact on natural gas consumption than it does in the residential, commercial, and transportation sectors. In the industrial sector, projected natural gas consumption in 2030 varies from 7.2 trillion cubic feet in the low growth case to 9.0 trillion cubic feet in the high growth case.

Natural gas consumption in the electric power sector is sensitive to natural gas prices because other fuels, such as coal, can be substituted directly for natural gas in generating electricity. In the high and low economic growth cases, however, natural gas consumption in the electric power sector shows little variation from the reference case projection. Natural gas use for electricity generation in 2030 varies from 5.0 trillion cubic feet in the low growth case to 4.9 trillion cubic feet in the high growth case. In the high economic growth case, when natural gas consumption in the electric power sector begins to rise, natural gas prices increase significantly, and in response coal and nuclear power are substituted for natural gas.

Projected Natural Gas Prices Fall from Current Levels Before Rising

Figure 76. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2006 dollars per thousand cubic feet)



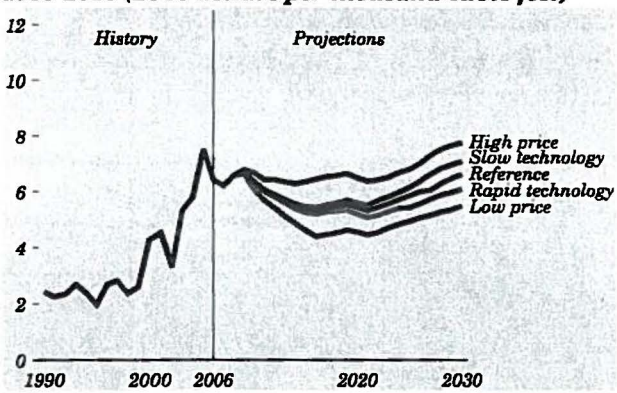
In the *AEO2008* reference case, lower 48 wellhead prices for natural gas are projected to decline from current levels to an average of $5.32 per thousand cubic feet (2006 dollars) in 2016, then rise to $6.63 per thousand cubic feet in 2030. Henry Hub spot market prices are projected to decline to $5.82 per million Btu ($5.99 per thousand cubic feet) in 2016 and then rise to $7.22 per million Btu ($7.43 per thousand cubic feet) in 2030 (Figure 76).

Current high natural gas prices are expected to stimulate the development of new gas supplies and constrain growth in natural gas consumption. Greater availability of natural gas supplies leads to a decline in prices through 2016. After 2016, wellhead natural gas prices increase largely as a result of the increased cost of developing the remaining U.S. natural gas resource base.

Natural gas prices in the reference case are determined largely by the cost of supplying natural gas from the remaining U.S. and Canadian resource base. In the future, however, the U.S. natural gas market is expected to become more integrated with natural gas markets worldwide, as a result of increased U.S. access to, and reliance on, LNG supplies from foreign sources. As a consequence, international market conditions will have a stronger influence on domestic natural gas prices in the United States, causing even greater uncertainty in future U.S. natural gas prices than would be the case if the United States relied exclusively on natural gas supplies from North America.

Prices Vary With Resource Size and Technology Progress Assumptions

Figure 77. Lower 48 wellhead natural gas prices, 1990-2030 (2006 dollars per thousand cubic feet)

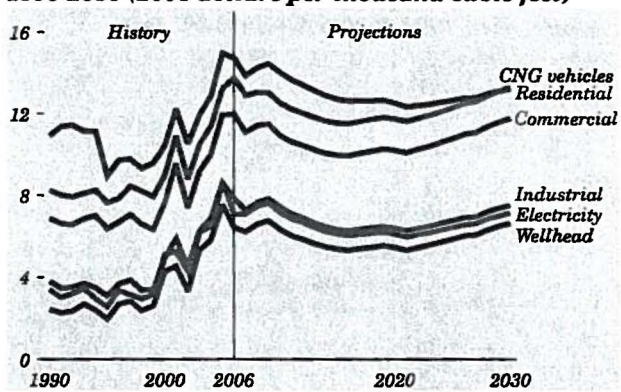


In the high price case, oil prices are assumed to be higher and the unproven natural gas resource base is assumed to be 15 percent smaller than the estimates used in the reference case. The low price case assumes lower oil prices and a 15-percent larger unproven resource base than in the reference case. A smaller domestic natural gas resource base increases exploration and production (E&P) costs, leading to higher natural gas prices. As a result, U.S. wellhead prices (and the price of LNG worldwide) are higher in the high price case and lower in the low price case than in the reference case (Figure 77). In 2030, domestic wellhead natural gas prices are projected to average $7.77 (2006 dollars) per thousand cubic feet in the high price case, compared with $5.49 per thousand cubic feet in the low price case.

Technological progress affects the future production of natural gas by reducing production costs and expanding the economically recoverable resource base. In the *AEO2008* reference case, the rate of improvement in natural gas production technology is based on the historical rate. The slow oil and natural gas technology case assumes an improvement rate 50 percent lower than in the reference case. As a result, future capital and operating costs are higher, causing the projected average wellhead price of natural gas to increase to $7.10 per thousand cubic feet in 2030. The rapid technology case assumes a rate of technology improvement 50 percent higher than in the reference case, reducing natural gas development and production costs. In the rapid technology case, wellhead natural gas prices are projected to average $6.11 per thousand cubic feet in 2030.

Delivered Natural Gas Prices Follow Trends in Wellhead Prices

Figure 78. Natural gas prices by end-use sector, 1990-2030 (2006 dollars per thousand cubic feet)



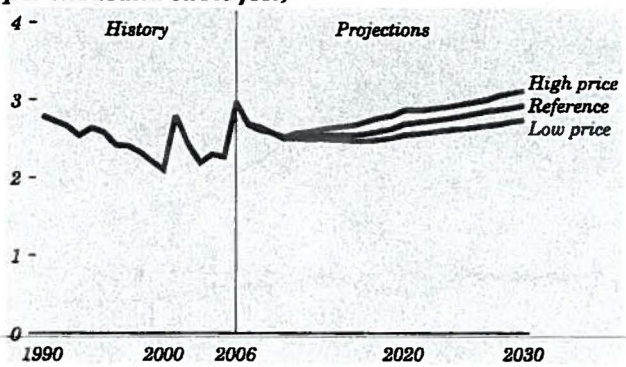
Trends in delivered natural gas prices largely reflect changes in projected wellhead prices. In the *AEO2008* reference case, prices for natural gas delivered to the end-use sectors decline through 2016 as wellhead natural gas prices decline, then increase along with wellhead prices over the rest of the projection period (Figure 78).

Natural gas transmission and distribution margins in the industrial and electric power sectors fall over time, because production facilities in those sectors typically are connected directly to transmission pipelines, and pipeline rates are projected to fall as their depreciation expenses decline more rapidly than their costs increase. In the residential and commercial sectors, in contrast, transmission and distribution rates for natural gas rise over time, because increases in building efficiency reduce natural gas consumption at each building site, and distribution expenses thus are spread over a lower total volume of system throughput. As a result, average U.S. transmission and distribution margins increase slowly from 2006 to 2030 in the reference case.

All the *AEO2008* cases assume that sufficient transmission and distribution capacity will be built to accommodate the projected growth in natural gas consumption. If public opposition were to prevent infrastructure expansion, however, delivered prices could be higher than projected.

Transmission and Distribution Margins Vary Inversely With Volumes

Figure 79. Average natural gas transmission and distribution margins, 1990-2030 (2006 dollars per thousand cubic feet)

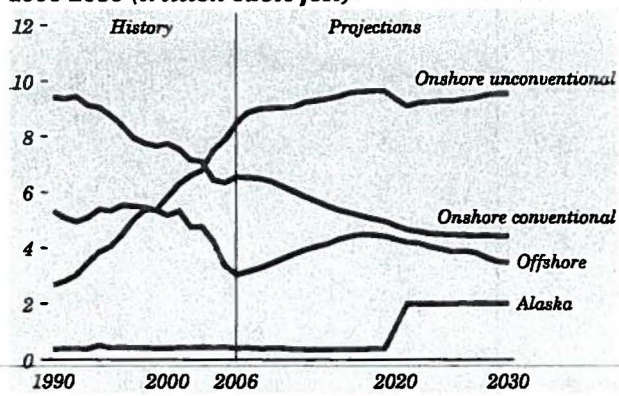


The transmission and distribution margin for natural gas delivered to end users is the difference between the average delivered price and the average source price, which is the quantity-weighted average of the lower 48 wellhead price and the average import price. It reflects both the capital and operating costs for pipelines and the volume of natural gas transported. Although operating costs vary with the level of pipeline utilization, capital costs are fixed for the most part. Variations in pipeline throughput result in higher or lower transmission and distribution costs per thousand cubic feet of natural gas transported. Thus, because the high and low price case projections show the greatest variation in total natural gas consumption, the greatest variation in transmission and distribution margins is also seen in those cases.

In the high price case, total natural gas consumption in 2030 is projected to be only 21.9 trillion cubic feet. As a result, the average transmission and distribution margin for delivered natural gas is projected to increase from $2.98 per thousand cubic feet in 2006 to $3.12 per thousand cubic feet in 2030 (2006 dollars). In the low price case, total natural gas consumption in 2030 grows to 24.8 trillion cubic feet, and the average transmission and distribution margin in 2030 drops to $2.74 per thousand cubic feet as the existing pipeline system is used at a higher capacity factor. In the reference case, with projected natural gas consumption of 22.7 trillion cubic feet in 2030, the projected average transmission and distribution margin in 2030 is $2.93 per thousand cubic feet (Figure 79).

Unconventional Production Is a Growing Source of U.S. Gas Supply

Figure 80. Natural gas production by source, 1990-2030 (trillion cubic feet)



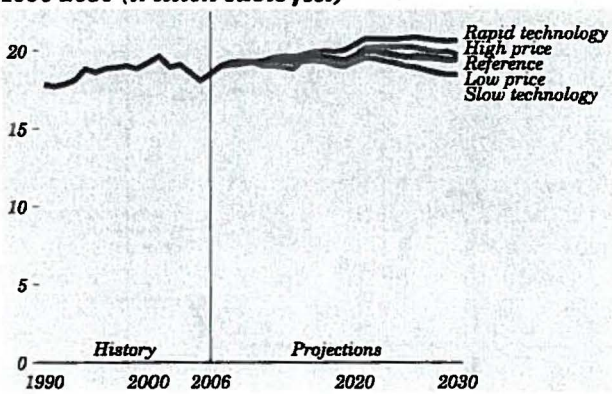
Total U.S. natural gas production grows modestly in the reference case, from 18.5 trillion cubic feet in 2006 to 19.4 trillion cubic feet in 2030, as depletion of the onshore lower 48 conventional resource base is offset by increased production from unconventional sources and from Alaska. Offshore production increases from 3.0 trillion cubic feet in 2006 to 4.5 trillion cubic feet in 2017, then declines to 3.5 trillion cubic feet in 2030. Production in shallow waters declines slowly through 2030. Production in deeper waters rises to 3.0 trillion cubic feet in 2019 and then declines through 2030.

A large proportion of the onshore lower 48 conventional natural gas resource base has been discovered. Discoveries of new conventional natural gas reservoirs are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Accordingly, total lower 48 onshore conventional natural gas production declines in the *AEO2008* reference case from 6.6 trillion cubic feet in 2006 to 4.4 trillion cubic feet in 2030 (Figure 80). Incremental production of lower 48 onshore natural gas comes primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. Lower 48 unconventional production increases in the reference case from 8.5 trillion cubic feet in 2006 to 9.5 trillion cubic feet in 2030.

The Alaska natural gas pipeline is expected to begin transporting natural gas to the lower 48 States in 2020. As a result, Alaska's natural gas production increases from 0.4 trillion cubic feet in 2006 to 2.0 trillion cubic feet in 2030 in the reference case.

Natural Gas Supply Projections Reflect Rates of Technology Progress

Figure 81. Total U.S. natural gas production, 1990-2030 (trillion cubic feet)



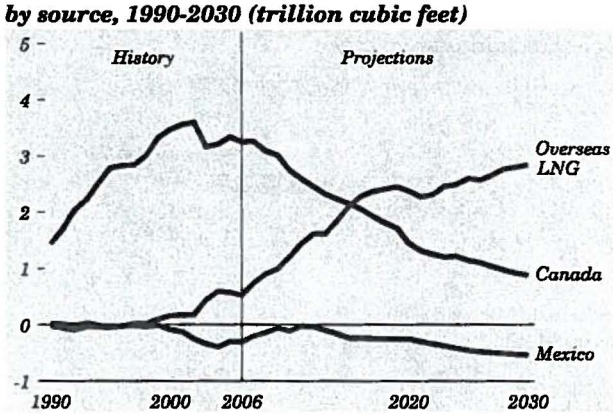
Exploration for and production of natural gas becomes more profitable when prices increase and when exploration and development costs decline. The rapid and slow technology cases show the effects of different assumed rates of technology improvement in the oil and natural gas industries, which directly affect exploration and development costs. The high and low price cases show the effects of different assumptions about oil price levels and the availability of unproved oil and natural gas resources.

Technological progress generally reduces the cost of natural gas production, leading to lower wellhead prices, more end-use consumption, and more production. More rapid progress works to increase domestic natural gas production and slower progress works to reduce production in the technology cases. U.S. natural gas production in 2030 is 6.4 percent higher in the rapid technology case and 4.8 percent lower in the slow technology case than in the reference case (Figure 81).

The high and low price cases show smaller effects on total production than do the technology cases. The high and low price cases include higher and lower oil prices and assume an unproven natural gas resource base that is 15 percent smaller (in the high price case) or 15 percent larger (in the low price case) than assumed in the reference case. In the high price case, the stimulative effect that higher natural gas prices normally would have on natural gas production is offset by an increase in E&P costs as a result of the smaller resource base.

Net Imports of Liquefied Natural Gas Grow in the Projection

Figure 82. Net U.S. imports of natural gas by source, 1990-2030 (trillion cubic feet)

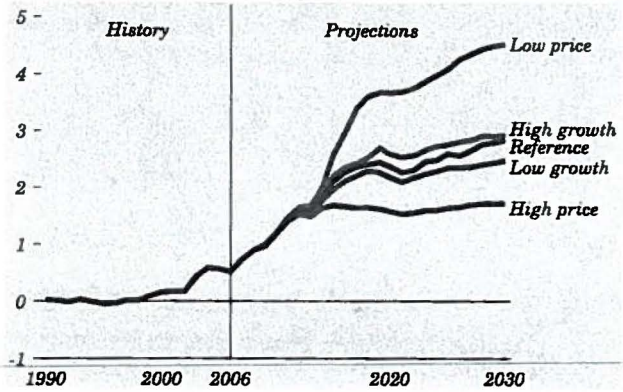


Net U.S. imports of natural gas from Canada are projected to decline, and net imports of LNG are projected to grow, from 2006 through 2030. Most of the expected growth in U.S. natural gas imports is in the form of LNG. The total capacity of U.S. LNG receiving terminals increases from 1.5 trillion cubic feet in 2006 to 5.2 trillion cubic feet in 2009 in the reference case (with no further increase through 2030), and net LNG imports grow from 0.5 trillion cubic feet in 2006 to 2.8 trillion cubic feet in 2030 (Figure 82). The U.S. market is expected to be tight throughout the projection because of competition for LNG supplies across the world. Although U.S. imports rise over time, they are expected to vary significantly from year to year, depending on domestic and worldwide natural gas prices. When international natural gas prices are higher than U.S. prices, LNG imports are expected to be lower, and vice versa. Thus, LNG imports in the *AEO2008* cases reflect the expected long-term trend rather than actual import levels in any particular year.

Over the past year, reported costs for development of the Mackenzie Delta natural gas pipeline, including development costs for the three anchor natural gas fields, have increased substantially [*87*]. Therefore, the pipeline is not expected to be built with natural gas prices at the levels projected in the *AEO2008* reference case. Canada still is expected to export natural gas to the United States in the reference case, however, with U.S. net imports from Canada declining from 3.2 trillion cubic feet in 2006 to 0.9 trillion cubic feet in 2030. Natural gas prices in the reference case are adequate to support that level of imports despite the absence of the Mackenzie Delta pipeline.

LNG Imports Are the Source of Supply Most Affected in the Price Cases

Figure 83. Net U.S. imports of liquefied natural gas, 1990-2030 (trillion cubic feet)



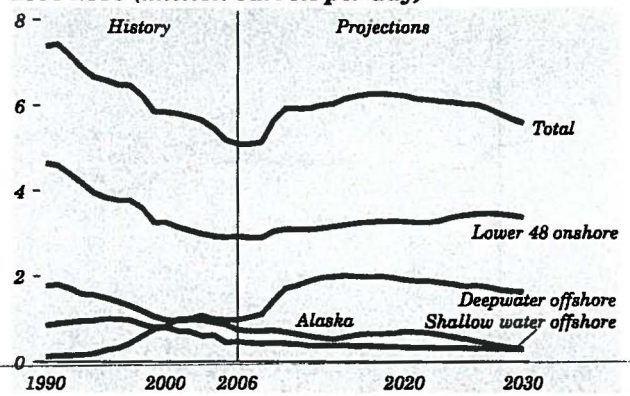
Net U.S. imports of LNG are expected to vary considerably from year to year, depending on both the level of U.S. natural gas prices and whether those prices are higher or lower than prices elsewhere in the world. Higher prices overseas are expected to reduce U.S. LNG imports, and lower prices overseas are expected to increase U.S. imports. U.S. LNG imports are much less sensitive to economic growth rates, which determine the level of domestic natural gas consumption. Given the uncertainty in future domestic and overseas natural gas prices, the level of future U.S. LNG imports is highly uncertain.

In the high price case, the higher world crude oil price is expected to result in increased natural gas consumption in overseas energy markets, exerting upward pressure on LNG prices. In addition, some LNG contract prices are tied directly to crude oil prices. Higher crude oil prices will also spur greater GTL production, placing additional pressure on world natural gas supplies. Collectively, these activities are expected to increase overseas wellhead natural gas prices and worldwide LNG prices, reducing both domestic natural gas consumption and LNG imports in the United States.

Net U.S. imports of LNG in 2030 are projected to total 2.8 trillion cubic feet in the reference case, 4.5 trillion cubic feet in the low price case, 1.7 trillion cubic feet in the high price case, 2.9 trillion cubic feet in the high economic growth case, and 2.5 trillion cubic feet in the low economic growth case (Figure 83).

U.S. Crude Oil Production Increases Slightly Through 2030

Figure 84. Domestic crude oil production by source, 1990-2030 (million barrels per day)

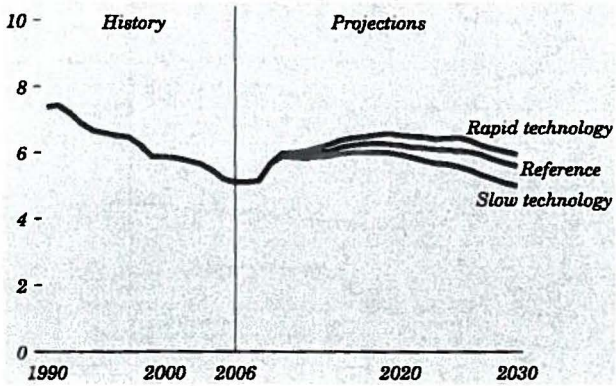


In the reference case, U.S. conventional oil production grows from 5.1 million barrels per day in 2006 to a peak of 6.3 million barrels per day in 2018, then declines to 5.6 million barrels per day in 2030 (Figure 84). The shape of the U.S. production profile is determined largely by lower 48 offshore oil production, which rises from 1.4 million barrels per day in 2006 to 2.4 million barrels per day in 2015 and then falls to 1.9 million barrels per day in 2030. Deepwater oil production in the Gulf of Mexico increases from 970,000 barrels per day in 2006 to a peak of 2.0 million barrels per day between 2013 through 2019, which is followed by a decline to 1.6 million barrels per day in 2030. Production in the shallower Gulf waters (at depths less than 1,000 feet) declines from 350,000 barrels per day in 2006 to 230,000 barrels per day in 2030. The decline in total offshore oil production during the later years of the reference case reflects depletion of the largest offshore oil fields and the fact that the remaining offshore oil resource base is composed of smaller and smaller fields.

Because a large portion of the U.S. onshore conventional oil resource base already has been produced, newly discovered oil reservoirs are expected to be smaller, more remote (e.g., Alaska), and more costly to exploit. Onshore oil production in the lower 48 States increases slightly, however, as higher crude oil prices stimulate production by EOR techniques using CO_2 injection, which increases from 350,000 barrels per day in 2006 to 1.3 million barrels per day in 2030. Excluding the increase in EOR production, lower 48 onshore oil production declines slowly, from 2.6 million barrels per day in 2006 to 2.1 million barrels per day in 2030.

More Rapid Technology Advances Could Raise U.S. Oil Production

Figure 85. Total U.S. crude oil production, 1990-2030 (million barrels per day)



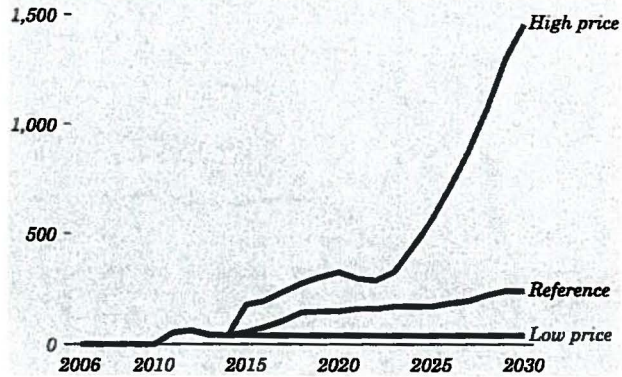
The rapid and slow oil and gas technology cases assume rates of technological progress in the petroleum industry that are 50 percent higher and 50 percent lower than in the reference case. The rate of technological progress determines the cost of developing and producing the remaining domestic oil resource base. Higher (or lower) rates of technological progress result in lower (or higher) oil development and production costs, which in turn allow more (or less) oil production. In 2030, domestic crude oil production is 5.6 million barrels per day in the reference case, 5.9 million barrels per day in the rapid technology case, and 5.0 million barrels per day in the slow technology case (Figure 85).

Domestic oil consumption, which is determined largely by oil prices and economic growth rates, does not vary significantly across the technology cases; however, imports of crude oil and petroleum products do vary, depending on domestic oil production levels. In 2030, net imports of crude oil and liquid fuels total 12.4 million barrels per day in the reference case, as compared with 12.0 million barrels per day in the rapid technology case and 13.0 million barrels per day in the slow technology case.

Higher rates of technological progress result in higher oil production rates and more rapid depletion of the domestic resource base. Cumulative U.S. crude oil production from 2006 through 2030 is 2.0 billion barrels (3.9 percent) higher in the rapid technology case and 2.6 billion barrels (4.9 percent) lower in the slow technology case than in the reference case.

Unconventional Liquids Production Increases With Higher Oil Prices

Figure 86. Total U.S. unconventional crude oil production, 2006-2030 (thousand barrels per day)

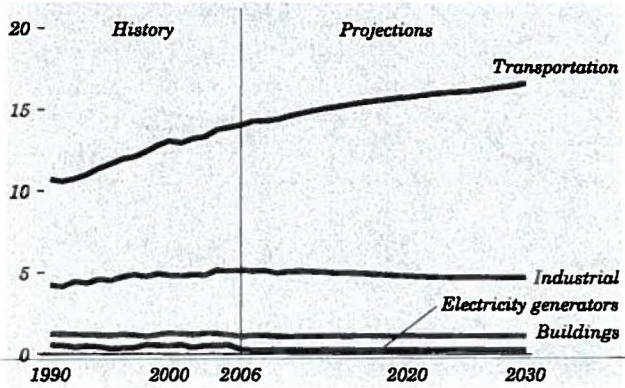


Crude oil prices are the primary determining factor for future levels of domestic unconventional oil production (such as oil shale, CTL, and GTL). In the *AEO2008* low price case, CTL production begins in 2011, using only U.S. facilities now under construction, and remains at 40,000 barrels per day through 2030. With the higher oil price in the reference case, CTL production starts in 2011 at about 50,000 barrels per day and increases to about 240,000 barrels per day in 2030 (Figure 86). In the high price case, both GTL and oil shale production become economical, and total domestic unconventional oil production increases to 1.5 million barrels per day in 2030—1.2 million barrels per day from CTL, 130,000 barrels per day from GTL, and 140,000 barrels per day from oil shale. In the high price case, both oil and natural gas prices are sufficiently high to encourage both the construction of an Alaska natural gas pipeline and GTL production on Alaska's North Slope.

There is considerable uncertainty surrounding the future of unconventional crude oil production in the United States. Environmental regulations could either preclude unconventional production or raise its cost significantly. If future U.S. laws limited and/or taxed greenhouse gas emissions, they could lead to substantial increases in the costs of unconventional production, which emits significant volumes of CO_2. Restrictions on access to water also could prove costly, especially in the arid West. In addition, environmental restrictions on land use could preclude unconventional oil production in some areas of the United States.

Transportation Uses Lead Growth in Liquid Fuels Consumption

Figure 87. Liquid fuels consumption by sector, 1990-2030 (million barrels per day)



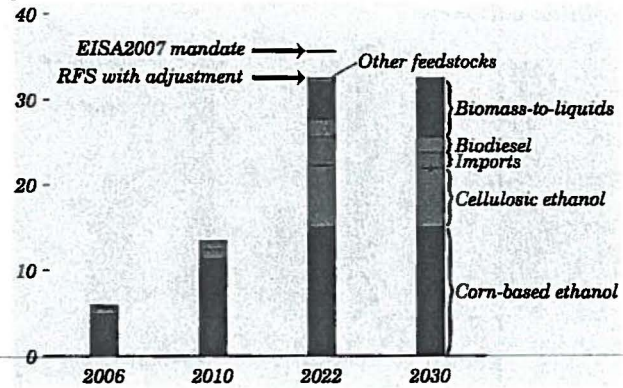
U.S. consumption of liquid fuels—including fuels from petroleum-based sources and, increasingly, those derived from nonpetroleum primary fuels such as coal, biomass, and natural gas—totals 22.8 million barrels per day in 2030 in the reference case, an increase of 2.1 million barrels per day over the 2006 total (Figure 87). All of the increase is in the transportation sector, which accounts for 73 percent of total liquid fuels consumption in 2030, up from 68 percent in 2006.

Gasoline, ULSD, and jet fuel are the main transportation fuels. The reference case includes the effects of technology improvements that are expected to increase the efficiency of motor vehicles and aircraft, but the projected growth in demand for each mode outpaces those improvements as the demand for transportation services grows in proportion to increases in population and GDP. With the new CAFE standards in EISA2007, transportation use of liquid fuels increases by 2.6 million barrels per day in the reference case, 3.9 million barrels per day in the high economic growth case, and 1.8 million barrels per day in the high price case from 2006 to 2030.

Consumption of liquid fuels from nonpetroleum sources increases substantially over the projection period. Ethanol, which made up 4 percent of the motor gasoline pool in 2006, increases to 15.8 percent of the total motor gasoline pool in 2030. Total production of liquid fuels from CTL and BTL plants, which are expected to commence operation in 2011, increases in the reference case to 540,000 barrels per day in 2030, equivalent to 9.7 percent of the total pool of distillate fuel.

RFS Is Defined by Multiple Biofuel Categories in EISA2007

Figure 88. EISA2007 RFS credits earned in selected years, 2006-2030 (billion credits)



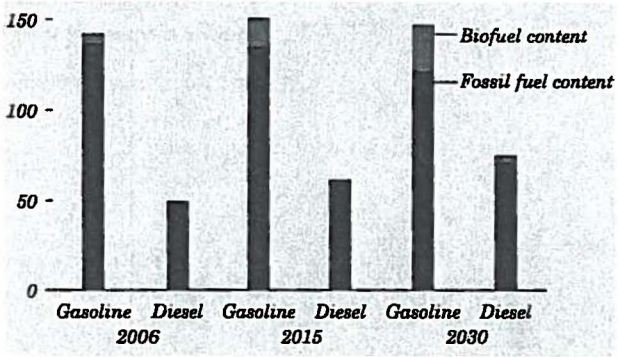
EISA2007 mandates a total RFS credit requirement of 36 billion gallons in 2022. Credits are equal to gallons produced, except for fatty acid methyl ester biodiesel and BTL diesel, which receive a 1.5-gallon credit for each gallon produced. The renewable fuels can be grouped into two categories: conventional biofuels (ethanol produced from corn starch) and advanced biofuels (including cellulosic ethanol, biodiesel, and BTL diesel). In total, 15 billion gallons of credits from conventional biofuels and 21 billion gallons from advanced biofuels are required in 2022.

In the *AEO2008* reference case, however, only 32.5 billion gallons of RFS credits are generated in 2022, because cellulosic biofuel production is not expected to increase rapidly enough to provide the credits that would be needed to meet the advanced biofuels requirement. If the available quantities of biofuels are inadequate to meet the initial targets, EISA2007 provides for both the application of waivers and modification of applicable credit volumes (Figure 88).

Corn ethanol is projected to make the largest contribution toward the RFS mandate, providing up to 15 billion credits. Cellulosic ethanol contributes 7.2 billion credits to the advanced and cellulosic biofuel requirement in 2022, and BTL diesel contributes 4.3 billion credits. BTL production continues to increase in the later years of the projection, to 6.8 billion gallons in 2030. The remainder of the credits for advanced biofuels in 2022 include credits for approximately 3 billion gallons of ethanol imports, 2 billion gallons of biodiesel, and 0.5 billion gallons of ethanol from wheat and other feedstocks.

EISA2007 Increases U.S. Supply of Renewable Transportation Fuels

Figure 89. Fossil fuel and biofuel content of U.S. motor fuel supply, 2006, 2015, and 2030 (billion gallons)

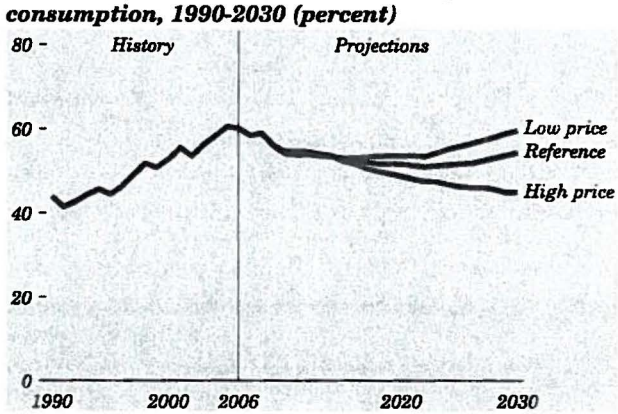


As a result of the EISA2007 RFS, the biofuel component of motor fuels in the transportation sector is projected to grow substantially, as the fossil fuel content of gasoline and diesel declines from 136 billion gallons (96 percent) in 2006 to 125 billion gallons (83 percent) in 2030 (Figure 89). The biofuel content of all gasoline and E85 consumed in the United States, which totaled about 5.6 billion gallons in 2006, increases to 25.8 billion gallons in 2030. In addition, a smaller increase in biofuel content is projected for diesel fuel, from 0.3 billion gallons in 2006 to 3.8 billion gallons in 2030.

Adding to the decline in U.S. consumption of fossil-fuel-based gasoline is a projected increase in diesel fuel use for passenger vehicles—a shift that is likely to require significant adjustments in the refining industry. Crude oil processing typically yields a sizable portion of product in the naphtha range, which frequently is used in motor gasoline. Historically, there has been a mutually beneficial relationship between U.S. and European refiners, with surplus diesel being shipped from the United States to Europe and surplus gasoline shipped from Europe to the United States. A significant increase in U.S. demand for diesel while the demand for gasoline is falling is likely to require significant investment by refiners in both the United States and Europe in order to maximize diesel yields.

Imports of Liquid Fuels Are Expected To Decline

Figure 90. Net import share of U.S. liquid fuels consumption, 1990-2030 (percent)



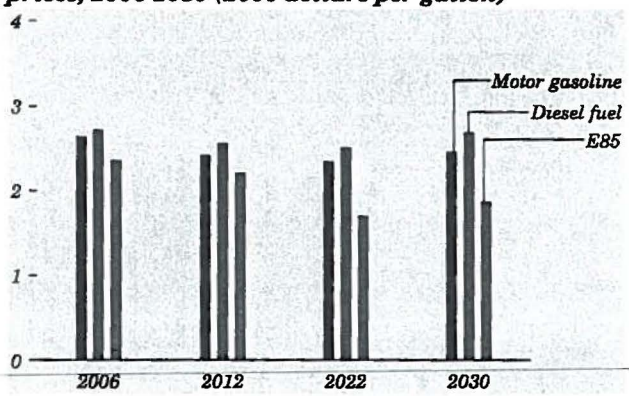
In 2006, net imports of liquid fuels, primarily petroleum, accounted for 60 percent of domestic consumption. In the reference case, U.S. dependence on liquid fuel imports declines to 51 percent in 2022, before climbing to 54 percent in 2030 (Figure 90). In the high price case, net imports as a share of domestic consumption of liquid fuels fall to 45 percent in 2030. In the low price case, dependence on petroleum imports remains roughly constant, with an import share of 59 percent in 2030.

In the reference case, demand for refined products continues to increase more rapidly than refining capacity. Historically, the availability of product imports has been limited by a lack of foreign refineries capable of meeting the stringent U.S. standards for liquids products. One example is provided by the U.S. ban on use of methyl tertiary butyl ether as an oxygenate in RFG. Since the ban took effect in January 2007, U.S. refiners have switched to using ethanol as the oxygenate in RFG, and the New York Mercantile Exchange (NYMEX) market has stopped offering imports of RFG and switched to imports of reformulated blendstock for oxygenate blending.

In recent years, however, liquids demand has grown rapidly in some countries of Eastern Europe and Asia, and those nations are moving to adopt the same fuel quality standards as the developed world. As a result, refineries throughout the world are becoming more sophisticated, and in the future more of them will be able to provide products suitable for the U.S. market, which they may do if it is profitable.

Ethanol Prices Compete on a Btu Basis To Meet the EISA2007 RFS

Figure 91. Motor gasoline, diesel fuel, and E85 prices, 2006-2030 (2006 dollars per gallon)

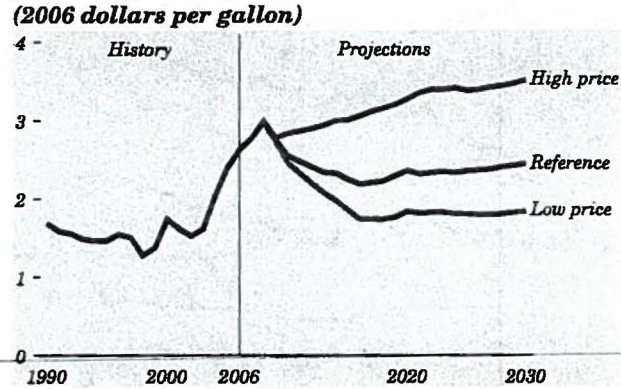


In the *AEO2008* reference case, with the EISA2007 renewable fuels mandate in effect, the U.S. market for E10 is saturated by 2014, after which the ethanol requirement is met by increased consumption of E85. To encourage the use of E85, its price is discounted to make it competitive with motor gasoline on an energy-equivalent basis. The E85 price discounts are funded by premiums placed on the petroleum content of other motor fuels. As E85 consumption increases, the price drops from $2.35 per gallon in 2006 to a low of $1.57 (2006 dollars) in 2017 before rising to $1.86 in 2030. In comparison, the price of motor gasoline is $2.63 per gallon in 2006 and $2.45 in 2030 (Figure 91).

In the low price case, E85 follows the same general price path, falling to $1.44 per gallon in 2030. In contrast, in the high price case, the price of E85 rises to $2.73 per gallon in 2030, although it is still discounted relative to motor gasoline, which increases to $3.52 per gallon in 2030. In the *AEO2008* early release, which excluded the impact of EISA2007, the price of E85 remained closer to the price of motor gasoline throughout the projection period, increasing to $2.29 per gallon in 2030, while the price of gasoline increased to $2.49 in 2030.

U.S. Motor Gasoline Prices Rise and Fall With Changes in World Oil Price

Figure 92. Average U.S. delivered prices for motor gasoline, 1990-2030 (2006 dollars per gallon)



Retail prices for petroleum products largely follow changes in crude oil prices. In the *AEO2008* reference case, the world oil price path reaches a low of $57 per barrel in 2016 and then increases to about $70 in 2030 (2006 dollars). The U.S. average motor gasoline price follows the same trend, falling to $2.19 per gallon in 2016 before rising to $2.45 in 2030.

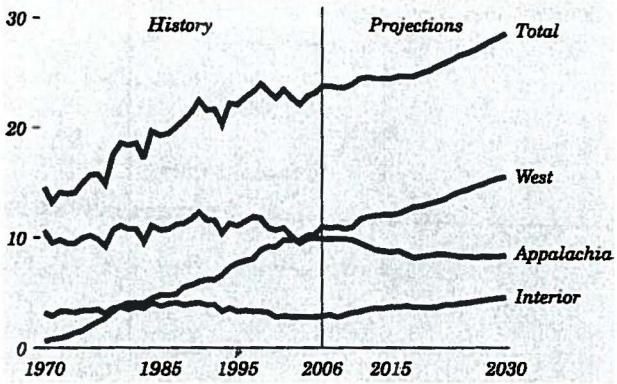
In the high price case, with the price of imported crude oil rising to $119 per barrel (2006 dollars) in 2030, the average price of U.S. motor gasoline increases rapidly, to $3.06 per gallon in 2016 and $3.52 per gallon in 2030. In the low price case, gasoline prices decline to a low of $1.74 per gallon in 2016, increase slowly through the early 2020s, and level off at about $1.84 per gallon through 2030 (Figure 92).

Because changes from the reference case assumptions for economic growth rates have less pronounced effects on motor gasoline prices than do changes in oil price assumptions, the average prices for U.S. motor gasoline in the high and low economic growth cases are close to those in the reference case. In the high growth case, the average gasoline price falls to a low of $2.24 per gallon in 2016 and then rises to $2.59 per gallon in 2030. In the low growth case, the average price reaches a low of $2.16 per gallon in 2017, followed by an increase to $2.32 per gallon in 2030.

In all the *AEO2008* cases, increases in motor gasoline prices as a result of the EISA2007 biofuel mandates are more than offset by erosion of the real dollar value of the Federal excise taxes. By assumption, the Federal gasoline tax is fixed at its 2007 nominal level of 18.4 cents per gallon.

Western Coal Production Continues To Increase Through 2030

Figure 93. Coal production by region, 1970-2030 (quadrillion Btu)



In the *AEO2008* reference case, increasing coal use for electricity generation at existing plants and construction of a few new coal-fired plants lead to annual production increases that average 0.3 percent per year from 2006 to 2015, when total production is 24.5 quadrillion Btu. In the absence of restrictions on CO_2 emissions, the growth in coal production is even stronger from 2015 to 2030, averaging 1.0 percent per year, as a substantial number of new coal-fired power plants and several CTL plants are brought on line.

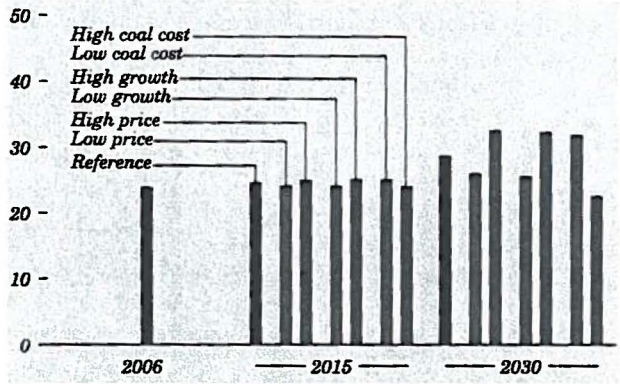
Western coal production, which has grown steadily since 1970, continues to increase through 2030 (Figure 93). Much of the projected growth is in output from the Powder River Basin, where producers are well positioned to increase production from the vast remaining surface-minable reserves.

Appalachian coal production declines slightly in the reference case. Although producers in Central Appalachia are well situated to supply coal to new generating capacity in the Southeast, that portion of the Appalachian basin has been mined extensively, and production costs have been increasing more rapidly than in other regions. The eastern portion of the Interior coal basin (Illinois, Indiana, and western Kentucky), with extensive reserves of mid- and high-sulfur bituminous coals, benefits from the new coal-fired generating capacity in the Southeast.

Production of low-Btu lignite in the Interior and Western supply regions also increases substantially, primarily to meet the energy and feedstock requirements of new coal-fired power plants and CTL plants in Texas, Montana, and North Dakota.

Long-Term Production Outlook Varies Considerably Across Cases

Figure 94. U.S. coal production, 2006, 2015, and 2030 (quadrillion Btu)

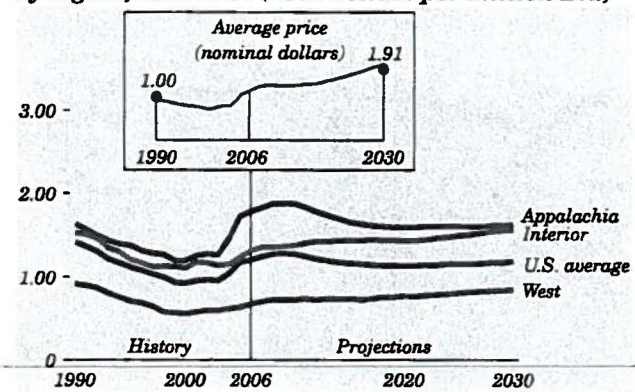


In most of the *AEO2008* cases, U.S. coal production is projected to increase from 2006 to 2030; however, different assumptions about economic growth (which mainly affect overall electricity demand) and about the costs of producing fossil fuels (which primarily determine the mix of supply sources for generation and petroleum products) lead to different results. The reference case projects a 20-percent increase from 2006 to 2030, whereas the alternative cases show changes that range from a decrease of 5 percent to an increase of 36 percent (Figure 94). Because the level of uncertainty is lower in the near term, the projected changes in coal production from 2006 to 2015 show significantly less variation, ranging from virtually no change to an increase of 5 percent.

Across the cases, regional coal production trends generally follow the national trend. As a result, the projected regional shares of total coal production in 2030 (from the Appalachian, Interior, and Western supply regions) do not vary by much among the reference, high and low price, and high and low economic growth cases. In the high coal cost case, however, the combination of higher mining and transportation costs and slow growth in total U.S. coal demand leads to a sizable drop in projected output from Wyoming's Powder River Basin, which is by far the most important coal-producing area in the West. As a result, the Western share of total U.S. coal production declines slightly in the high coal cost case, from 46 percent in 2006 to 45 percent in 2030. In the other cases, the West's share of total coal production in 2030 ranges from a low of 54 percent to a high of 60 percent.

Minemouth Coal Prices in the Western and Interior Regions Rise Steadily

Figure 95. Average minemouth price of coal by region, 1990-2030 (2006 dollars per million Btu)



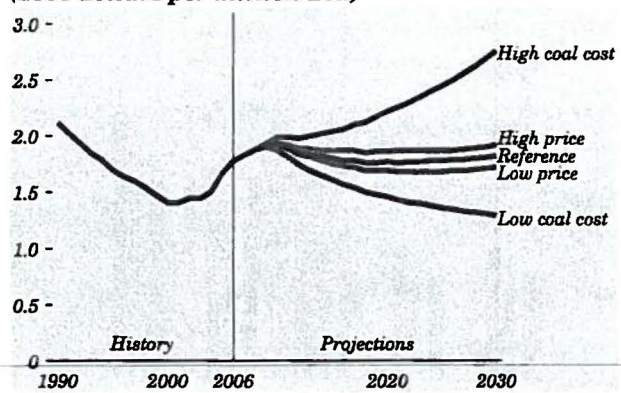
Strong growth in production in the Interior and Western supply regions, combined with limited improvement in coal mining productivity, results in minemouth price increases of 0.7 and 0.9 percent per year, respectively, for the two regions from 2006 through 2030. Average minemouth prices in Appalachia decline by 0.4 percent per year over the same period, as a result of falling output levels and a shift to lower cost production in the northern part of the basin.

The U.S. average minemouth price for coal drops slightly between 2006 and 2020, from $1.21 to $1.14 per million Btu (2006 dollars), as mine capacity utilization declines and production shifts away from the higher cost mines of Central Appalachia. After 2020, rising natural gas prices and requirements for additional generating capacity result in the construction of 65 gigawatts of new coal-fired generating capacity. The combination of new investment in mining capacity to meet the demand growth, a continued low rate of productivity improvement, and rising utilization of mining capacity leads to an increase in the average minemouth price, to $1.19 per million Btu in 2030.

From 1990 to 1999, the average minemouth price of coal declined by 4.5 percent per year (Figure 95). Increases in U.S. coal mining productivity of 6.3 percent per year helped to reduce mining costs and contributed to the price decline. Since 1999, U.S. coal mining productivity has declined by 0.8 percent per year, and the average minemouth coal price has increased by 3.7 percent per year. In the *AEO2008* reference case, coal mining productivity rises at an average rate of 0.6 percent per year from 2006 to 2030, more closely reflecting the trend of the past several years.

Higher Mining and Transportation Costs Raise Delivered Coal Prices

Figure 96. Average delivered coal prices, 1990-2030 (2006 dollars per million Btu)



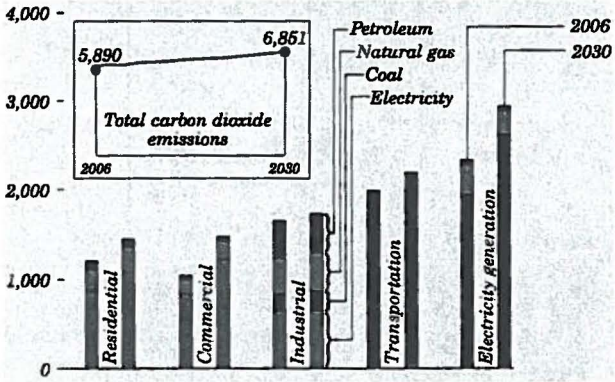
Alternative assumptions for coal mining and transportation costs affect delivered coal prices and demand. Two alternative coal cost cases developed for *AEO2008* examine the impacts on U.S. coal markets of alternative assumptions about mining productivity, labor costs, and mine equipment costs on the production side, and about railroad productivity and rail equipment costs on the transportation side.

In the high coal cost case, the average delivered coal price in 2006 dollars is $2.76 per million Btu in 2030—52 percent higher than in the reference case (Figure 96). As a result, U.S. coal consumption is 4.8 quadrillion Btu (16 percent) lower than in the reference case in 2030, reflecting both a switch from coal to natural gas, nuclear, and renewables in the electricity sector and reduced CTL production. In the low coal cost case, the average delivered price in 2030 is $1.29 per million Btu—29 percent lower than in the reference case—and total coal consumption is 2.1 quadrillion Btu (7 percent) higher than in the reference case.

Because the high and low economic growth cases and the high and low price cases use the reference case assumptions for coal mining and rail transportation productivity and equipment costs, they show smaller variations in average delivered coal prices than do the two coal cost cases. Different coal price projections in the high and low economic growth cases (with price paths very close to the reference case) and high and low price cases result mainly from higher and lower projected levels of demand for coal. In the price cases, higher and lower fuel costs for both coal producers and railroads contribute to the variations in projected coal prices.

Rising Energy Consumption Increases Carbon Dioxide Emissions

Figure 97. Carbon dioxide emissions by sector and fuel, 2006 and 2030 (million metric tons)

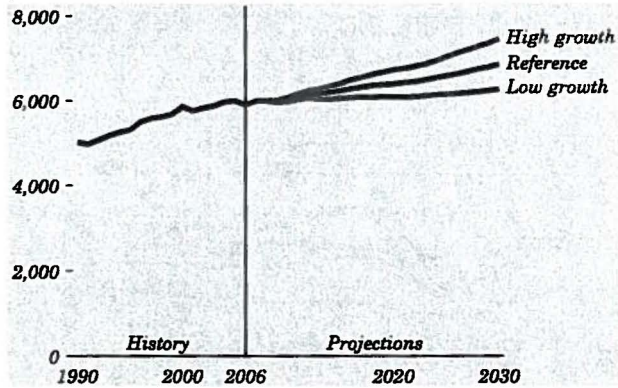


Without capture and sequestration, CO_2 emissions from the combustion of fossil fuels are proportional to the carbon content of the fuel. Coal has the highest carbon content and natural gas the lowest, with petroleum in between. In the *AEO2008* reference case, the shares of these fuels change slightly from 2006 to 2030, with more coal and less oil and natural gas. The combined share of renewable and nuclear energy grow from 15 percent in 2006 to 20 percent in 2030. As a result, CO_2 emissions increase by 16 percent over the period, as compared with a 19-percent increase in total energy use (Figure 97). At the same time, the economy becomes less carbon intensive: the percentage increase in CO_2 emissions is one-fifth the increase in GDP, and emissions per capita decline by 5 percent over the 24-year period.

The factors that influence growth in CO_2 emissions are the same as those that drive increases in fossil energy demand. Among the most significant are population and economic growth; increased penetration of computers, electronics, appliances, and office equipment; increases in commercial floorspace; increases in highway, rail, and air travel; and continued reliance on coal for electric power generation. The increases in demand for energy services are partially offset by efficiency improvements and shifts toward less energy-intensive industries. New CO_2 mitigation programs, more rapid improvements in technology, or more rapid adoption of voluntary CO_2 emissions reduction programs could result in lower CO_2 emissions levels than projected here.

Emissions Projections Change With Economic Growth Assumptions

Figure 98. Carbon dioxide emissions, 1990-2030 (million metric tons)



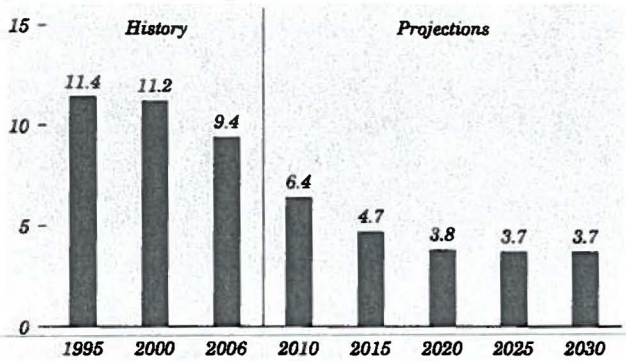
Higher growth in population, labor force, and productivity is assumed in the high growth case than in the reference case, leading to higher industrial output, higher disposable income, lower inflation, and lower interest rates. The low growth case assumes the reverse. In the high and low growth cases, GDP varies by about 14 percent and population by about 8 percent from the reference case projections for 2030.

Alternative projections for industrial output, commercial floorspace, housing, and transportation in the population and economic growth cases influence the demand for energy and result in variations in CO_2 emissions (Figure 98). Emissions in 2030 are 9 percent lower in the low growth case and 9 percent higher in the high growth case than in the reference case. The strength of the relationship between economic growth and emissions varies by end-use sector. It is strongest for the industrial sector and, to a lesser extent, the transportation sector, where economic activity strongly influences energy use and emissions, and where fuel choices are limited. It is weaker in the commercial and residential sectors, where population and building characteristics have large influences and vary less across the three cases.

Changes in electricity sales across the cases affect the amount of new, more efficient generating capacity required, reducing somewhat the sensitivity of energy use to GDP. However, the choice of coal for most new baseload capacity increases CO_2 intensity in the high growth case while decreasing it in the low growth case, offsetting the effects of changes in efficiency across the cases.

Clean Air Interstate Rule Reduces Sulfur Dioxide Emissions

Figure 99. Sulfur dioxide emissions from electricity generation, 1995-2030 (million short tons)



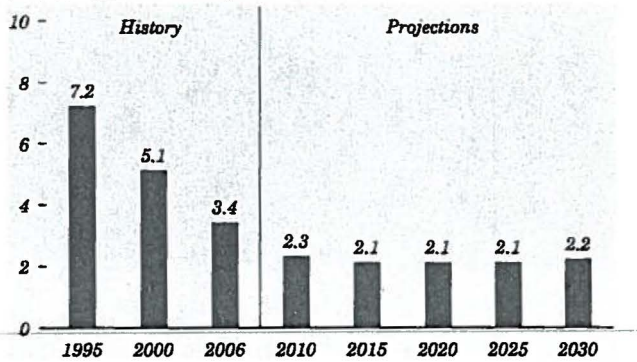
SO_2 emissions are expected to fall as CAIR takes effect [*88*]. States can achieve mandated emissions reductions in two ways: by requiring power plants to participate in the EPA's national cap and trade program or by requiring them to meet State-specific emissions milestones through more stringent measures chosen by the State.

In the *AEO2008* reference case, national SO_2 emissions from electricity generation fall from 9.4 million short tons in 2006 to 3.7 million short tons in 2030 (Figure 99). The reduction results from both the use of lower sulfur coal and the addition of flue gas desulfurization equipment on 125 gigawatts of existing capacity. SO_2 allowance prices rise steadily throughout the early years of the projection, to more than $1,000 per ton in 2020. After 2020, allowance prices slowly decline, settling below $500 in 2030.

SO_2 emissions are not greatly affected by economic growth, as shown in the *AEO2008* high economic growth case. Because many new coal-fired power plants are equipped to remove SO_2 before beginning operation, the allowance prices are no higher than in the reference case. Fuel price assumptions have a greater effect on SO_2 allowance prices. With more CTL plants expected to be constructed in the high price case, potential emissions from coal combustion increase; however, CTL plants are expected to have SO_2 capture equipment that is more efficient than the equipment on advanced pulverized coal plants. Thus, in the later years of the projection, SO_2 allowance prices are slightly lower in the high price case than in the reference case.

Nitrogen Oxide Emissions Also Fall As CAIR Takes Effect

Figure 100. Nitrogen oxide emissions from electricity generation, 1995-2030 (million short tons)



CAIR also mandates NO_x emission reductions in 28 States and the District of Columbia [*89*]. The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. As with the CAIR-mandated SO_2 reductions, each State can determine a preferred method for reducing NO_x emissions. *AEO2008* assumes that all the States covered by CAIR will participate in interstate trading of allowances.

In the *AEO2008* reference case, national NO_x emissions from the electric power sector fall from 3.4 million short tons in 2006 to 2.2 million short tons in 2030 (Figure 100). Because the CAIR caps are inflexible, different assumptions in the high and low economic growth and high and low price cases have little affect on cumulative NO_x emissions. The projections for cumulative NO_x emissions over the projection period are lowest in the low economic growth case—0.5 percent lower than in the reference case.

After mandatory compliance begins, NO_x allowance prices range between $2,500 and $3,400 per ton emitted in the reference case, tending to rise as the emission caps tighten. In 2030, selective catalytic reduction equipment is projected to have been added on an additional 98 gigawatts of coal-fired generating capacity in the reference case. In the high economic growth case, NO_x allowances are more costly. The construction of more coal-fired power plants to meet a higher level of demand for electricity, and the resulting need for additional retrofits, pushes allowance prices to approximately $3,800 in 2025, after which the price stabilizes.

Comparison With Other Projections

Comparison with Other Projections

Only Global Insights, Inc. (GII) produces a comprehensive energy projection with a time horizon similar to that of *AEO2008*. Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from GII, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2008* projections.

Economic Growth

Projections of the average annual GDP growth rate for the United States from 2006 through 2010 range from 2.4 percent to 2.8 percent (Table 7). GDP grows at an annual rate of 2.4 percent in the *AEO2008* reference case over the period, significantly lower than the projections made by the Office of Management and Budget (OMB), the Congressional Budget Office (CBO), the Interindustry Forecasting Project at the University of Maryland (INFORUM), the Social Security Administration (SSA), and Energy Ventures Analysis, Inc. (EVA). The *AEO2008* projection is slightly lower than the projections by the International Energy Agency (IEA) and GII. The consensus Blue Chip projection is for 2.5-percent average annual growth from 2006 to 2010.

The range of GDP growth rates is wider for the period from 2010 to 2015, with projections ranging from 2.3 to 2.9 percent per year. The average annual GDP growth of 2.7 percent in the *AEO2008* reference case from 2010 to 2015 is around the middle of the range. The Blue Chip consensus projection is 2.9 percent, CBO projects 2.8 percent, and EVA projects 2.7 percent for the annual rate of GDP growth from 2010 to 2015. The GII, INFORUM, SSA, and IEA projections all are below the *AEO2008* reference case projection.

Table 7. Projections of annual average economic growth rates, 2006-2030

	Average annual percentage growth rates			
Projection	2006-2010	2010-2015	2015-2020	2020-2030
AEO2007 (reference case)	2.9	2.8	3.0	2.8
AEO2008 (reference case)	2.4	2.7	2.4	2.4
GII	2.5	2.5	2.5	2.4
OMB	2.7	NA	NA	NA
CBO	2.6	2.8	NA	NA
Blue Chip	2.5	2.9	NA	NA
INFORUM	2.6	2.5	2.3	2.3
SSA	2.7	2.3	2.1	2.0
EVA	2.8	2.7	2.4	2.1
IEA	2.6	2.6	2.2	2.2

NA = not available.

There are few public or private projections of GDP growth rates for the United States that extend to 2030. The *AEO2008* reference case reflects a GDP growth rate after 2015 that is consistent with the trend in expected labor force and productivity growth.

World Oil Prices

Comparisons of the *AEO2008* cases with other oil price projections are shown in Table 8. In the *AEO2008* reference case, world oil prices fall from current levels through 2016 and then gradually rise to about $70 in real terms (2006 dollars). Given current prices, this pattern of falling and then rising oil prices is seen in all the long-term projections, with the exception of GII's, which consistently declines. The world oil price measures are, by and large, comparable across projections. EIA reports the price of imported low-sulfur, light crude oil, approximately the same as the West Texas Intermediate (WTI) prices that are widely cited as a proxy for world oil prices in the trade press. The only series that does not report projections in WTI terms is IEA's *World Energy Outlook 2007*, where prices are expressed as the IEA crude oil import price.

Recent volatility in crude oil prices demonstrates the uncertainty inherent in the projections. GII and Deutsche Bank AG (DB) define the range of crude oil price projections for 2030, from a low of about $46 per barrel (GII) to a high of $80 per barrel (DB). The *AEO2008* reference case projects a world oil price of about $70 per barrel in 2030.

Total Energy Consumption

The *AEO2008* reference case projects growth in end-use consumption of natural gas and coal, in contrast to the decline that occurred from 1980 to 2006 (Table 9). Natural gas consumption increases in the residential, commercial, and industrial sectors, despite relatively high prices. Natural gas is cleaner than other fuels, does not require on-site storage, and has tended to be priced competitively with oil for

Table 8. Projections of world oil prices, 2010-2030 (2006 dollars per barrel)

Projection	2010	2015	2020	2025	2030
AEO2007 (reference case)	59.21	51.37	53.61	58.07	60.91
AEO2008 (reference case)	74.03	59.85	59.70	64.49	70.45
GII	68.25	61.40	54.80	48.20	45.70
IEA (reference)	59.03	57.30	58.87	60.43	62.00
DB	56.65	60.00	66.00	72.00	80.00
SEER	69.41	58.85	60.83	62.88	65.00

heating. Coal consumption as a boiler fuel in the commercial and industrial sectors declines slightly, with potential use in new boilers limited by environmental restrictions; however, the projections for industrial coal consumption include its use in CTL plants, a technology that becomes competitive at the level of oil prices in the *AEO2008* reference case.

The projected growth in consumption of liquids, including ethanol blends and biodiesel, from 2006 to 2030 is about one-half the average from 1980 to 2006. Transportation is the only sector for which liquids consumption grows significantly, offsetting a moderate decline in the industrial sector. Continued growth in fuel use for transportation is expected despite high prices and newly tightened fuel economy standards. With economic growth, an increasing population, and rising per capita income, demand for personal and freight travel increases. Although the average fuel efficiency of vehicles and airplanes continues to improve, the changes under currently enacted laws and regulations are insufficient to offset the projected increase in transportation demand.

Growth in electricity use continues in the *AEO2008* reference case, but the pace slows to one-half the historical rate. Some rapidly growing applications, such as air conditioning and computers, slow as penetration approaches saturation levels. Electrical efficiency also continues to improve, due in large part to efficiency standards, and the impacts tend to accumulate with the gradual turnover of appliance stocks.

The *AEO2008* reference case includes higher growth in primary and delivered energy from 2006 to 2030 than is shown in the outlook from GII. GII projects little growth in end-use natural gas consumption, whereas the *AEO2008* reference case projects continued growth in the industrial and buildings sectors (see Table 11). GII's projected growth rates for liquids consumption are somewhat higher than those in the *AEO2008* reference case, which includes the impacts of EISA2007 on vehicle fuel economy (see Table 12). Differences between the *AEO2008* reference case and the GII projections for end-use coal consumption result from a projected increase in coal use for CTL in the *AEO2008* reference case (see Table 13).

Electricity

Table 10 provides a summary of the results from the *AEO2008* cases and compares them with other projections. Electricity sales in 2015 range from a low of 4,059 billion kilowatthours in the *AEO2008* reference case to a high of 4,319 billion kilowatthours in the EVA projection. EVA shows higher sales in the commercial and residential sectors and somewhat less growth in industrial sales than do the *AEO2008* reference case and GII. The projections for total electricity sales in 2030 are about the same (4,705 billion kilowatthours) in the *AEO2008* reference case and GII, which are the only projections available that include 2030. The annual rate of demand growth in both projections is about 1.1 percent per year from 2006 to 2030. In 2030, GII includes lower growth in the commercial sector and higher growth in the residential and industrial sectors compared with the *AEO2008* reference case.

The *AEO2008* reference case shows a decline in real electricity prices early in the projection period and then rising prices at the end of the period because of increases in the cost of fuels used for generation and increases in capital expenditures for construction of new capacity. The higher fossil fuel prices and capital expenditures in the *AEO2008* reference case result in an increase in the average electricity price, from 8.5 cents per kilowatthour in 2015 to 8.8 cents per kilowatthour in 2030. GII shows slightly declining prices over the projection period.

Total generation and imports of electricity in 2015 are similar in the *AEO2008* reference case, EVA, and GII. In contrast, the IEA projection for electricity generation in its *World Energy Outlook 2007* is higher than the other projections. Generation in the IEA projection for the United States (which exclude imports of electricity) are higher than in any of the *AEO2008* cases. Consistent with higher total electricity generation, the IEA projection includes higher

Table 9. Projections of average annual growth rates for energy consumption, 2006-2030 (percent)

Energy use	History 1980-2006	Projections	
		AEO2008	GII
*Delivered energy**			
*Petroleum liquids***	0.9	0.4	0.6
Natural gas	-0.1	0.6	0.3
Coal	-1.7	0.6	-0.1
Electricity	2.2	1.1	1.0
Total	0.7	0.7	0.6
Electricity losses	1.8	0.8	0.4
Primary energy	0.9	0.7	0.6

**Excludes consumption by electricity generators in the electric power sector; includes consumption for end-use combined heat and power generation.*

***Includes ethanol and biodiesel used as transportation fuels.*

Comparison with Other Projections

Table 10. Comparison of electricity projections, 2015 and 2030 (billion kilowatthours, except where noted)

Projection	2006	AEO2008 reference case	Other projections		
			GII	EVA	IEA
		2015			
Average end-use price (2006 cents per kilowatthour)	**8.9**	**8.5**	**8.8**	**NA**	**NA**
Residential	10.4	10.2	10.2	10.98	NA
Commercial	9.5	8.7	9.3	9.82	NA
Industrial	6.1	5.9	6.0	6.37	NA
Total generation plus imports	**4,069**	**4,496**	**4,531**	**4,547**	**4,959**
Coal	1,988	2,182	2,171	2,219	2,552
Oil	63	57	64	66	133
Natural gas [a]	811	909	920	936	858
Nuclear	787	807	827	825	849
Hydroelectric/other [b]	403	529	533	486	567
Net imports	18	11	17	15	NA
Electricity sales	**3,659**	**4,059**	**4,116**	**4,319**	**NA**
Residential	1,351	1,472	1,553	1,625	NA
Commercial/other [c]	1,306	1,529	1,489	1,683	NA
Industrial	1,002	1,058	1,074	1,011	NA
Capability, including CHP (gigawatts) [d]	**983**	**1,016**	**1,019**	**1,050**	**NA**
Coal	314	329	326	341	NA
Oil and natural gas	444	437	430	482	NA
Nuclear	100	102	104	104	NA
Hydroelectric/other	125	148	160	123	NA
		2030			
Average end-use price (2006 cents per kilowatthour)	**8.9**	**8.8**	**8.7**	**NA**	**NA**
Residential	10.4	10.5	10.1	NA	NA
Commercial	9.5	8.9	9.2	NA	NA
Industrial	6.1	6.0	5.8	NA	NA
Total generation plus imports	**4,069**	**5,258**	**5,180**	**NA**	**5,947**
Coal	1,988	2,836	2,557	NA	3,148
Oil	63	66	55	NA	102
Natural gas [a]	811	745	905	NA	896
Nuclear	787	917	888	NA	933
Hydroelectric/other [b]	403	670	761	NA	869
Net imports	18	23	14	NA	NA
Electricity sales	**3,659**	**4,705**	**4,706**	**NA**	**NA**
Residential	1,351	1,722	1,793	NA	NA
Commercial/other [c]	1,306	1,950	1,724	NA	NA
Industrial	1,002	1,033	1,189	NA	NA
Capability, including CHP (gigawatts) [d]	**983**	**1,204**	**1,086**	**NA**	**NA**
Coal	314	414	378	NA	NA
Oil and natural gas	444	504	375	NA	NA
Nuclear	100	115	115	NA	NA
Hydroelectric/other	125	172	218	NA	NA

[a]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas. [b]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies. [c]"Other" includes sales of electricity to government, railways, and street lighting authorities. [d]EIA capacity is net summer capability, including CHP plants. GII capacity is nameplate, excluding cogeneration plants.

CHP = combined heat and power. NA = not available.

Sources: ***2006 and AEO2008:*** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **GII:** Global Insight, Inc., *Global Petroleum Outlook, Fall 2007* (Lexington, MA, November 2007). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2007). **IEA:** International Energy Agency, *World Energy Outlook 2007* (Paris, France, November 2007).

levels of generation from fossil and renewable technologies in 2030 than do the *AEO2008* cases. The requirements for generating capacity are driven by growth in electricity sales and the need to replace existing units that are uneconomical or are being retired for other reasons. Consistent with its projections of electricity sales, EVA shows higher growth in fossil-based generating capacity through 2015 compared with the *AEO2008* reference case and GII; however, EVA projects considerably less renewable capacity in 2015 than do *AEO2008* and GII.

Renewable generating capacity in 2030 is higher in the GII projection than in the *AEO2008* reference case. Nuclear capacity in 2030 is 115 gigawatts in both *AEO2008* and GII, as a result of the incentives included in EPACT2005. The *AEO2008* reference case includes 2.7 gigawatts of uprates for nuclear capacity and 4.5 gigawatts of nuclear plant retirements by 2030 as their operating licenses expire. Environmental regulations are important determinants in the selection of the technologies used for electricity generation. In addition to existing environmental program requirements for electric utilities, EVA assumes that new, stricter national emissions limits will be adopted for emissions of SO_2 and NO_x by 2015. EVA also includes an escalating penalty on CO_2 emissions, starting at $6 per ton in 2013.

The *AEO2008* cases include the impact of the EPA's CAIR regulation [*90*]. Because *AEO2008* includes only current laws and regulations, however, it does not assume any tax on CO_2 emissions. Restrictions on CO_2 emissions could change the mix of technologies used to generate electricity.

Natural Gas

In the *AEO2008* reference case, total natural gas consumption increases through 2016 and then declines through 2030 as higher natural gas prices cause natural gas to lose market share to coal for electricity generation. With the exception of the Altos and Strategic Energy and Economic Research, Inc. (SEER) projections, all the other projections show total natural gas consumption increasing throughout the projection period (Table 11). Altos shows a slight decline in natural gas consumption after 2025, and SEER shows almost the same level of natural gas consumption in 2025 and 2030.

The *AEO2008* reference case projects the lowest level of natural gas consumption in 2030, followed by GII (about 1.0 trillion cubic feet more than in the *AEO2008* reference case). The Altos projection includes the highest growth rate for natural gas consumption, reaching 31.4 trillion cubic feet in 2030 (8.7 trillion cubic feet more than in the *AEO2008* reference case). The DB and SEER projections show natural gas consumption in 2030 exceeding the *AEO2008* reference case projection by 1.8 and 2.6 trillion cubic feet, respectively. Although GII projects lower natural gas consumption in 2030 in the residential and commercial sectors than is projected in the *AEO2008* reference case, natural gas consumption for electricity generation in the GII projection is much greater, resulting in higher aggregate natural gas demand than in the *AEO2008* reference case, highlighting a fundamental difference between the *AEO2008* reference case and GII projections. This difference can also be seen in a comparison of the *AEO2008* reference case with the Altos and SEER projections.

Natural gas consumption in the electricity generation sector grows from 2006 to 2015 in all the projections. (DB does not include projections by sector.) Growth in natural gas consumption in the electricity generation sector is projected to continue through 2025 in the EVA and Altos projections. The *AEO2008* reference case shows the lowest level of natural gas consumption for electric power in 2025, at 5.3 trillion cubic feet, followed by GII at 6.9 trillion cubic feet.

All the projections show a decline in natural gas consumption in the electric power sector between 2025 and 2030, with the largest decline in the Altos projection (0.8 trillion cubic feet). Despite the large decline in natural gas consumption in the power sector in the Altos projection, it remains the most optimistic, with 2030 consumption projected to be 13.6 trillion cubic feet—almost three times higher than that in the *AEO2008* reference case. The SEER and GII projections for natural gas consumption in the electric power sector in 2030 are higher than the *AEO2008* reference case projection by 2.0 trillion cubic feet and 1.8 trillion cubic feet, respectively.

Each of the projections—with the exception of GII, which expects a slight decline between 2015 and 2030—shows steady growth in natural gas consumption in the combined residential and commercial sectors. Altos projects the highest level of natural gas consumption in the residential and commercial sectors in 2030 (9.3 trillion cubic feet), followed by SEER (9.0 trillion cubic feet) and the *AEO2008* reference case (8.8 trillion cubic feet). Each of the projections

shows an increase in natural gas consumption in the industrial sector between 2006 and 2015. That growth is projected to continue through 2025 in each of the projections except for the *AEO2008* reference case. The *AEO2008* projection shows a decline in industrial sector natural gas consumption between 2025 and 2030, whereas the other projections show increases.

Domestic natural gas production increases through 2015 in each of the projections, with Altos showing the highest production level in 2015, at 21.9 trillion cubic feet. The *AEO2008* reference case and GII show domestic natural gas production continuing to increase through 2025, whereas DB, SEER, and Altos show production declines over the same period. For example, DB shows domestic natural gas production declining by 3.0 trillion cubic feet from 2015 to 2025. All the projections show a decline in production from 2025 to 2030, with DB projecting the lowest level of production in 2030 (3.0 trillion cubic feet lower than in the *AEO2008*

Table 11. Comparison of natural gas projections, 2015, 2025, and 2030 (trillion cubic feet, except where noted)

Projection	2006	AEO2008 reference case	Other projections				
			GII	EVA	DB	SEER	Altos
			2015				
Dry gas production [a]	18.51	19.52	18.66	NA	19.66	20.33	21.90
Net imports	3.46	4.03	4.55	7.81	NA	4.71	6.75
Pipeline	2.94	1.91	1.90	3.05	NA	1.68	2.03
LNG	0.52	2.12	2.65	4.75	3.04	3.03	4.72
Consumption	21.66	23.66	23.36	25.56	23.74	25.79	26.98
Residential	4.37	5.01	4.98	5.06	NA	5.08	5.05
Commercial	2.83	3.20	3.03	3.23	NA	3.12	3.44
Industrial [b]	6.49	7.00	6.65	7.09	NA	6.66	7.54 [c]
Electricity generators [d]	6.24	6.56	6.97	8.24	NA	9.03	10.95
Other [e]	1.73	1.88	1.73	1.94	NA	1.89	NA
Lower 48 wellhead price (2006 dollars per thousand cubic feet) [f]							
	6.42	5.36	6.54	5.49	7.75	6.89	6.07
End-use prices (2006 dollars per thousand cubic feet)							
Residential	13.80	11.54	11.98	NA	NA	11.45	NA
Commercial	11.85	9.97	10.69	NA	NA	9.97	NA
Industrial [g]	7.89	6.33	8.38	NA	NA	6.97	NA
Electricity generators	7.07	6.10	7.15	NA	NA	7.61	NA
			2025				
Dry gas production [a]	18.51	19.60	18.73	NA	16.68	19.43	19.60
Net imports	3.46	3.28	4.64	9.49	NA	5.48	13.86
Pipeline	2.94	0.68	1.28	2.44	NA	0.44	2.76
LNG	0.52	2.60	3.36	7.05	8.77	5.04	11.10
Consumption	21.66	22.99	23.52	28.21	24.26	25.27	31.70
Residential	4.37	5.19	4.98	5.09	NA	5.31	5.15
Commercial	2.83	3.53	2.98	3.51	NA	3.40	3.87
Industrial [b]	6.49	6.96	6.96	7.99	NA	7.08	8.29 [c]
Electricity generators [d]	6.24	5.30	6.90	9.45	NA	7.49	14.39
Other [e]	1.73	2.02	1.71	2.17	NA	2.00	NA
Lower 48 wellhead price (2006 dollars per thousand cubic feet) [f]							
	6.42	5.86	6.63	5.40	7.75	6.40	7.00
End-use prices (2006 dollars per thousand cubic feet)							
Residential	13.80	12.29	11.89	NA	NA	11.13	NA
Commercial	11.85	10.78	10.63	NA	NA	9.40	NA
Industrial [g]	7.89	6.76	8.42	NA	NA	6.47	NA
Electricity generators	7.07	6.44	7.20	NA	NA	7.03	NA

NA = not available. See notes and sources at end of table.

reference case). The *AEO2008* reference case shows domestic natural gas production of 19.4 trillion cubic feet in 2030—the highest of all the projections.

Net imports of natural gas are projected to increase between 2006 and 2015 in each of the projections. EVA projects the highest level of net imports at 7.8 trillion cubic feet, followed by Altos at 6.8 trillion cubic feet. The *AEO2008* reference case shows a drop in net imports between 2015 and 2030. Each of the other projections shows net imports increasing steadily from 2006 to 2030 (Altos expects an increase of 12.1 trillion cubic feet over the period). In addition, all the projections show the increases in net imports coming primarily from LNG. Altos projects LNG net import levels in 2030 that are more than four times higher than in the *AEO2008* reference case, at 12.6 trillion cubic feet. The projections have LNG imports accounting for between 13 and 40 percent of consumption in 2030.

Given that the average wellhead price for natural gas in 2006 was $6.42 per thousand cubic feet, each of the projections shows a decline in natural gas prices between 2006 and 2015, except GII, DB, and SEER. The *AEO2008* reference case projects the lowest average wellhead prices in 2015, at $5.36 per thousand cubic feet. EVA's natural gas price projection for 2025 is lower than that in the *AEO2008* reference case, by about $0.46 per thousand cubic feet. DB consistently projects relatively high average wellhead prices between 2006 and 2030. Among the other projections, only GII and SEER project an average natural gas wellhead price below that in the *AEO2008* reference case in 2030. In the GII and SEER projections, natural gas wellhead prices in 2030 are below the *AEO2008* reference case projection by $0.15 and $0.13 per thousand cubic feet, respectively, and wellhead prices in the DB and Altos projections exceed the *AEO2008* reference case projection by $1.12 and $0.82 per thousand cubic feet, respectively.

Table 11. Comparison of natural gas projections, 2015, 2025, and 2030 (continued)
(trillion cubic feet, except where noted)

Projection	2006	AEO2008 reference case	Other projections				
			GII	EVA	DB	SEER	Altos
		2030					
Dry gas production [a]	18.51	19.43	18.68	NA	16.44	18.63	18.90
Net imports	3.46	3.18	4.86	NA	NA	6.33	15.57
Pipeline	2.94	0.33	0.76	NA	NA	0.20	2.95
LNG	0.52	2.84	4.10	NA	9.84	6.13	12.62
Consumption	21.66	22.72	23.69	NA	24.53	25.29	31.42
Residential	4.37	5.17	4.94	NA	NA	5.44	5.17
Commercial	2.83	3.67	2.97	NA	NA	3.57	4.12
Industrial [b]	6.49	6.87	7.18	NA	NA	7.29	8.50 [c]
Electricity generators [d]	6.24	4.99	6.83	NA	NA	6.98	13.63
Other [e]	1.73	2.02	1.76	NA	NA	2.01	NA
Lower 48 wellhead price (2006 dollars per thousand cubic feet) [f]							
	6.42	6.63	6.48	NA	7.75	6.50	7.45
End-use prices (2006 dollars per thousand cubic feet)							
Residential	13.80	13.30	11.67	NA	NA	11.30	NA
Commercial	11.85	11.78	10.42	NA	NA	9.44	NA
Industrial [g]	7.89	7.50	8.26	NA	NA	6.53	NA
Electricity generators	7.07	7.13	7.05	NA	NA	6.28	NA

NA = not available.

[a]Does not include supplemental fuels. [b]Includes consumption for industrial CHP plants, a small number of electricity-only plants, and GTL plants for heat and power production; excludes consumption by nonutility generators. [c]Includes lease and plant fuel. [d]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators. [e]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. [f]2006 wellhead natural gas prices for GII, DB, and SEER are $6.41, $6.42, and $6.24 per thousand cubic feet, respectively. [g]The 2006 industrial natural gas price for GII is $8.89 per thousand cubic feet.

Sources: **2006 and *AEO2008*:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **GII:** Global Insight, Inc., *2007 U.S. Energy Outlook* (October 2007). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2007). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 18, 2007. **SEER:** Strategic Energy and Economic Research, Inc., *Natural Gas Scenarios* (March 2008). **Altos:** Altos World Gas Trade (September 2007).

The price margins for delivered natural gas can vary significantly from year to year. In 2006, margins in the residential, commercial, industrial, and transportation sectors were notably higher than the historical average, and margins in the electricity generation sector were somewhat lower than the historical average. Starting from a level more representative of the historical average, margins in the electricity generation and industrial sectors generally decline in the *AEO2008* reference case. In contrast, margins in the residential and commercial sectors increase, because the fixed costs are spread over lower per-customer volumes as consumption is reduced by efficiency improvements.

End-use prices in the GII and SEER projections imply declining margins in all sectors, with the exception of the residential and electricity generation sectors in the SEER projection, which increase from 2025 to 2030. As a result, the GII and SEER margins in the residential and commercial sectors are lower than those in the *AEO2008* reference case projection by between $1.20 and $2.20 per thousand cubic feet in 2030. The industrial margin in the GII projection remains appreciably higher throughout the projection period, whereas the industrial margin in the SEER projection is between $0.83 and $0.90 per thousand cubic feet lower than the margins in the *AEO2008* reference case projection from 2015 to 2030. In fact, the SEER industrial margins appear to be only a few pennies in all years.

Petroleum

In the DB projection, real crude oil prices increase from $57 per barrel in 2010 to $80 per barrel in 2030. In the *AEO2008* reference case, real prices decline from current levels to a low of $57 per barrel in 2016 before recovering to $70 per barrel in 2030 (Table 8).

Despite the higher crude oil prices in 2030, the import share of product supplied is much higher in the DB projection than in the *AEO2008* reference case (74 percent and 54 percent, respectively). Although this may seem counterintuitive given the relative price projections, it makes sense in terms of the projections for domestic crude oil production. In the DB projection, U.S. crude oil production declines sharply after 2015, to 4.8 million barrels per day in 2030 (as compared with 7.2 million barrels per day in 2030 in the *AEO2008* reference case) (Table 12). In fact, U.S. crude oil production is lower in all the other projections than in the *AEO2008* reference case.

It is clear that expectations about U.S. crude oil production potential are among the main factors accounting for the differences between the *AEO2008* reference case and the other projections. In addition, unlike the DB analysis, the *AEO2008* reference case incorporates the effects of the new RFS mandate under EISA2007, which was signed into law in December 2007. With the new RFS mandate, biofuel consumption is projected to increase significantly through 2022, with more than 23 billion gallons of ethanol and almost 4 billion gallons of biomass-based diesel consumed in 2030, which would displace a significant amount of fossil fuel use in the transportation sector and, thereby, further reduce imports.

GII's long-term projections for the crude oil price in 2025 ($48 per barrel) and 2030 ($46 per barrel) are much lower than those in the *AEO2008* reference case (see Table 8). The GII projection for import share of product supplied is therefore higher than the *AEO2008* reference case projection.

In contrast with crude oil production, projections for NGL production are similar (remaining relatively constant) in the EVA, GII, and *AEO2008* reference case projections through 2030. The exception is DB, which projects a 26-percent decrease in domestic NGL production from 2015 to 2030.

Based on expectations of continued economic growth, all the petroleum projections show continued growth in product demand; however, growth in demand for individual petroleum products varies considerably. In particular, motor gasoline demand, which in the DB projections increases to 11.2 million barrels per day in 2030, is much lower in the GII and *AEO2008* reference case projections. Motor gasoline demand declines over time in the GII and *AEO2008* reference case projections (although it increases slightly from 2025 to 2030 in the *AEO2008* reference case). The GII projection includes a substantial increase in ethanol use (not shown in the Table 12) stemming from new, unspecified motor fuel policies, with ethanol making up more than 30 percent of total U.S. motor gasoline sales in 2030. A 30-percent share is in excess of even the new RFS mandate incorporated in *AEO2008*.

Looking at other petroleum products, the GII projections for jet fuel and distillate demand are higher than those in the DB and *AEO2008* reference case projections. The most likely explanation is that, although long-term GDP growth rates are similar in

Table 12. Comparison of petroleum projections, 2015, 2025, and 2030 (million barrels per day, except where noted)

Projection	2006	AEO2008 reference case	Other projections			
			GII	EVA	DB	IEA
			2015			
Crude oil and NGL production	**6.84**	**7.86**	**6.37**	**7.40**	**6.47**	**6.70**
Crude oil	5.10	6.16	4.63	5.60	4.92	NA
Natural gas liquids	1.74	1.70	1.75	1.80	1.55	NA
Total net imports	**12.45**	**11.36**	**13.79**	**NA**	**14.00**	**NA**
Crude oil	10.09	9.89	12.02	NA	NA	NA
Petroleum products	2.36	1.47	1.77	NA	NA	NA
Petroleum demand	**20.65**	**21.68**	**22.36**	**NA**	**22.07**	**22.45**
Motor gasoline	9.25	9.73	9.83	NA	9.84	NA
Jet fuel	1.63	1.85	1.92	NA	1.71	NA
Distillate fuel	4.17	4.68	4.79	NA	4.63	NA
Residual fuel	0.69	0.69	0.68	NA	0.71	NA
Other	4.91	4.73	5.14	NA	5.18	NA
Import share of product supplied (percent)	**60**	**52**	**62**	**NA**	**63**	**NA**
			2025			
Crude oil and NGL production	**6.84**	**7.65**	**5.47**	**5.80**	**5.28**	**NA**
Crude oil	5.10	6.04	3.71	4.10	4.01	NA
Natural gas liquids	1.74	1.61	1.75	1.70	1.27	NA
Total net imports	**12.45**	**11.38**	**15.13**	**NA**	**17.25**	**NA**
Crude oil	10.09	10.11	13.70	NA	NA	NA
Petroleum products	2.36	1.27	1.43	NA	NA	NA
Petroleum demand	**20.65**	**22.25**	**23.54**	**NA**	**24.25**	**NA**
Motor gasoline	9.25	8.84	9.08	NA	10.77	NA
Jet fuel	1.63	2.16	2.36	NA	1.90	NA
Distillate fuel	4.17	5.19	5.98	NA	5.16	NA
Residual fuel	0.69	0.69	0.65	NA	0.75	NA
Other	4.91	5.37	5.47	NA	5.67	NA
Import share of product supplied (percent)	**60**	**51**	**64**	**NA**	**71**	**NA**
			2030			
Crude oil and NGL production	**6.84**	**7.16**	**5.05**	**NA**	**4.78**	**6.30**
Crude oil	5.10	5.59	3.30	NA	3.63	NA
Natural gas liquids	1.74	1.57	1.75	NA	1.15	NA
Total net imports	**12.45**	**12.29**	**15.63**	**NA**	**18.75**	**NA**
Crude oil	10.09	11.03	14.51	NA	NA	NA
Petroleum products	2.36	1.26	1.12	NA	NA	NA
Petroleum demand	**20.65**	**22.80**	**24.04**	**NA**	**25.30**	**23.87**
Motor gasoline	9.25	8.91	8.47	NA	11.20	NA
Jet fuel	1.63	2.31	2.61	NA	2.00	NA
Distillate fuel	4.17	5.53	6.69	NA	5.43	NA
Residual fuel	0.69	0.70	0.63	NA	0.77	NA
Other	4.91	5.35	3.35	NA	5.90	NA
Import share of product supplied (percent)	**60**	**54**	**65**	**NA**	**74**	**NA**

NA = Not available.

Sources: ***2006 and AEO2008:*** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **GII:** Global Insight, Inc., *2007 U.S. Energy Outlook* (October 2007). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2007). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 18, 2007. **IEA:** International Energy Agency, *World Energy Outlook 2007* (Paris, France, November 2007).

the GII and *AEO2008* projections, the long-term cost of crude oil, as noted above, is much lower in the GII projection, leading to cheaper refined products and therefore higher demand. Finally, among the outside projections, IEA projects the lowest level of U.S. petroleum demand in 2030—probably as a result of IEA's assumption of slower U.S. economic growth. Further, although IEA's projection for U.S. petroleum demand in 2030 (23.9 million barrels per day) is higher than in the *AEO2008* reference case (22.8 million barrels per day), it would in fact be about 1 million barrels per day *lower* if *AEO2008* had not included the EISA2007 RFS mandate.

Coal

Coal production, trade, and price projections vary considerably across the three projections shown in Table 13. The coal projection in the *AEO2008* reference case reflects existing environmental laws that regulate SO_2, NO_x, and mercury emissions. The *AEO2008* reference case projections for coal consumption, production, and imports are generally higher than the projections from other sources.

All the projections show increases in total coal consumption over their projection periods. In the *AEO2008* reference case, total coal consumption

Table 13. Comparison of coal projections, 2015, 2025, and 2030 (million short tons, except where noted)

Projection	2006	AEO2008 reference case	Other projections	
			GII	EVA
		2015		
Production	1,163	1,215	1,135	1,225
Consumption by sector				
Electric power	1,026	1,125	1,055	1,121
Coke plants	23	21	23	23
Coal-to-liquids	0	16	NA	NA
Other industrial/buildings	65	64	65	71
Total	1,114	1,225	1,143	1,216
Net coal exports	15.3	3.3	-8.0	13.2
Exports	49.6	45.3	31.8	45.9
Imports	34.3	42.0	39.7	32.7
Minemouth price				
(2006 dollars per short ton)	24.63	23.38	19.68	25.14
(2006 dollars per million Btu)	1.21	1.17	0.94 [a]	1.23
Average delivered price to electricity generators				
(2006 dollars per short ton)	33.85	34.24	31.92	NA
(2006 dollars per million Btu)	1.69	1.74	1.52 [a]	NA
		2025		
Production	1,163	1,363	1,140	1,311
Consumption by sector				
Electric power	1,026	1,303	1,058	1,224
Coke plants	23	20	22	21
Coal-to-liquids	0	46	NA	NA
Other industrial/buildings	65	62	66	67
Total	1,114	1,431	1,146	1,311
Net coal exports	15.3	-57.3	-5.9	-1.9
Exports	49.6	35.5	31.1	43.3
Imports	34.3	92.8	36.9	45.2
Minemouth price				
(2006 dollars per short ton)	24.63	22.75	18.75	26.49
(2006 dollars per million Btu)	1.21	1.16	0.89 [a]	1.31
Average delivered price to electricity generators				
(2006 dollars per short ton)	33.85	34.03	30.61	NA
(2006 dollars per million Btu)	1.69	1.74	1.46 [a]	NA

Btu = British thermal unit. NA = Not available. See notes and sources at end of table.

grows by an average of 1.1 percent annually from 2006 to 2015, to 1,225 million tons in 2015. Although the reference case projection is 82 million tons higher than the corresponding projection from GII, it is similar to the EVA projection for total coal consumption in 2015. For 2025, both EVA and GII project lower levels of total coal consumption than the *AEO2008* reference case (8 percent and 20 percent lower, respectively). For 2030, GII projects total coal consumption of 1,175 million tons, 370 million tons less than in the *AEO2008* reference case.

Coal use in the electricity sector accounts for a large percentage of total coal consumption in all years across all the projections. Relative to the *AEO2008* reference case, both EVA and GII project slower growth in coal consumption for the electric power sector over the entire projection period. EVA projects total coal consumption in the electricity sector of 1,224 million tons in 2025, 79 million tons less than in the *AEO2008* reference case. The GII projection for coal consumption in the electric power sector is 1,088 million tons in 2030, 313 million tons less than in the *AEO2008* reference case.

The *AEO2008* reference case includes the introduction of CTL production before 2015, with coal use at CTL plants increasing to 64 million tons (4 percent of total coal consumption) in 2030. Projections for CTL production from the other organizations are not available for comparison [*91*].

The *AEO2008* reference case, GII, and EVA projections show relatively constant coal consumption levels both at coke plants and in the other industrial/buildings sector. The EVA projections do not extend to 2030. GII shows 21 million tons of coal consumption at coke plants and 66 million tons in the other industrial/buildings sector in 2030, both somewhat higher than in the *AEO2008* reference case (18 and 62 million tons, respectively).

In the *AEO2008* reference case, minemouth coal prices are generally flat over the projection period. EVA projects an increase to $26.49 in 2025, the highest among the projections compared, whereas the *AEO2008* reference case projection for 2025 is $22.75 per ton. In GII's projection, the minemouth coal price falls to $18.42 per ton in 2030. GII also projects a decline in delivered coal prices to the electric power sector through 2030, from $31.92 per ton in 2015 to $30.42 per ton in 2030—$4.61 per ton less than in the *AEO2008* reference case.

Table 13. Comparison of coal projections, 2015, 2025, and 2030 (continued)
(million short tons, except where noted)

Projection	2006	AEO2008 reference case	Other projections	
			GII	EVA
		2030		
Production	1,163	1,455	1,168	NA
Consumption by sector				
Electric power	1,026	1,401	1,088	NA
Coke plants	23	18	21	NA
Coal-to-liquids	0	64	NA	NA
Other industrial/buildings	65	62	66	NA
Total	1,114	1,545	1,175	NA
Net coal exports	15.3	-77.7	-7.0	NA
Exports	49.6	34.6	30.8	NA
Imports	34.3	112.3	37.8	NA
Minemouth price				
(2006 dollars per short ton)	24.63	23.32	18.42	NA
(2006 dollars per million Btu)	1.21	1.19	0.88 [a]	NA
Average delivered price to electricity generators				
(2006 dollars per short ton)	33.85	35.03	30.42	NA
(2006 dollars per million Btu)	1.69	1.78	1.45 [a]	NA

Btu = British thermal unit. NA = Not available.
[a]Imputed using heat conversion factor implied by US steam coal consumption figures for the electricity sector.
Sources: ***2006 and AEO2008:*** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **GII:** Global Insight, Inc., *2007 U.S. Energy Outlook* (October 2007). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2007).

Comparison with Other Projections

In the *AEO2008* and EVA projections, domestic coal production increases to meet rising demand. Production grows most rapidly in the *AEO2008* reference case, averaging 0.9 percent per year from 2006 to 2030. The EVA projection through 2025 closely resembles that in the *AEO2008* reference case, and the GII projection is significantly lower. In the GII projection, coal production totals 1,168 million tons in 2030, 20 percent less than in the *AEO2008* reference case (1,455 million tons).

U.S. coal exports represent a small percentage of domestic coal production in all the projections. Coal exports decline to less than 35 million tons in 2030 in the *AEO2008* reference case and GII projections, and the United States is represented as a net importer of coal after 2015 in all the projections. In the EVA projection, U.S. coal imports increase to 45 million tons in 2025, and exports are 43 million tons in 2025. In the *AEO2008* reference case, U.S. coal imports in 2015, 2025, and 2030 are higher than in the other projections.

List of Acronyms

A.B.	Assembly Bill
ABT	Averaging, banking, and trading
ACP	Alternative compliance payment
AEO	*Annual Energy Outlook*
AEO2007	*Annual Energy Outlook 2007*
AEO2008	*Annual Energy Outlook 2008*
AMFA	Alternative Motor Fuels Act of 1988
ANWR	Arctic National Wildlife Refuge
BTL	Biomass-to-liquids
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CBO	Congressional Budget Office
CCS	Carbon capture and sequestration
CEPCI	Chemical Engineering Plant Cost Index
CEPS	Clean energy portfolio standard
CFL	Compact fluorescent light bulb
CHP	Combined heat and power
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DB	Deutsche Bank AG
DOE	U.S. Department of Energy
E&P	Exploration and production
E10	Gasoline containing up to 10 percent ethanol by volume
E85	Fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume
EIA	Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT1992	Energy Policy Act of 1992
EPACT2005	Energy Policy Act of 2005
EVA	Energy Ventures Analysis, Inc.
FFV	Flex-fuel vehicle
FY	Fiscal year
GDP	Gross domestic product
GHGs	Greenhouse gases
GII	Global Insights, Inc.
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
H.R.	House of Representatives
ICAP	International Carbon Action Partnership
IEA	International Energy Agency
IECC	International Energy Conservation Code
INFORUM	Interindustry Forecasting Project at the University of Maryland
JAS	Joint Association Survey of Drilling Costs
LDV	Light-duty vehicle
LED	Light-emitting diode
LNG	Liquefied natural gas
MMS	Minerals Management Service
mpg	Miles per gallon
MSAT2	Mobile Source Air Toxics Rule (February 2007)
MSW	Municipal solid waste
NEMA	National Electrical Manufacturers Association
NEMS	National Energy Modeling System (EIA)
NGL	Natural gas liquids
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
OECD	Organization for Economic Cooperation and Development
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
P.L.	Public Law
PTC	Production tax credit
PV	Solar photovoltaic
R&D	Research and development
REC	Renewable energy certificate
RFG	Reformulated gasoline
RFS	Renewable Fuels Standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SEER	Strategic Energy and Economic Research, Inc.
S.B.	Senate Bill
SO_2	Sulfur dioxide
SSA	Social Security Administration
STEO	*Short-Term Energy Outlook* (EIA)
ULSD	Ultra-low-sulfur diesel
USGS	U.S. Geological Survey
VEETC	Volumetric Ethanol Excise Tax Credit
WCI	Western Climate Initiative
WTI	West Texas Intermediate (crude oil)

Text Notes

Overview

1. Some possible policy changes—notably, the adoption of policies to limit or reduce greenhouse gas emissions—could change the reference case projections significantly. EIA has examined many of the proposed greenhouse gas policies at the request of Congress; the reports are available on EIA's web site (see "Responses to Congressional and Other Requests," web site www.eia.doe.gov/oiaf/service_rpts.htm).
2. The comparison of production levels was adjusted for the entry of Angola into OPEC in late 2007.
3. See Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007), "Impact of Rising Construction and Equipment Costs on Energy Industries," pp. 36-41.
4. Vehicles that can use alternative fuels or employ electric motors and advanced electricity storage, advanced engine controls, or other new technologies.
5. Biodiesel is defined as the monoalkyl esters of fatty acids derived from plant or animal matter and suitable for use in a diesel engine.
6. BTL is defined as diesel fuel and other liquid hydrocarbons produced by a Fischer-Tropsch process using cellulosic biomass as feedstock.

Legislation and Regulations

7. U.S. Environmental Protection Agency, 40 CFR Parts 59, 80, 85 and 86 [EPA-HQ-OAR-2005-0036; FRL-8278-4], RIN 2060-AK70, "Control of Hazardous Air Pollutants from Mobile Sources; Final Rule," *Federal Register*, Vol. 72, No. 37 (February 26, 2007), web site http://edocket.access.gpo.gov/2007/pdf/E7-2667.pdf. Most of the data cited here were taken from this source.
8. For the complete text of the Energy Independence and Security Act of 2007, see web site http:// frwebgate.acess.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_public_laws&docid=f:publ140.110.pdf.
9. See, for example, web site http://energy.senate.gov/public/_files/HR6EnergyBillSummary.pdf.
10. Footprint is the product of track width and wheelbase, measured in square feet.
11. Energy Policy Act of 2005, Section 1501.
12. "DuPont and BP Reveal Biobutanol Test Results" *Ethanol & Biodiesel News* (April 23, 2007).
13. DuPont, "Alternative Fuels and Potential Material Compatibility Issues," DuPont Automobile Annual Fuel Luncheon (April 16, 2008).
14. Energy Information Administration, *Annual Energy Outlook 2007*, DOE-EIA-0383(2007) (Washington, DC, February 2007), "Legislation and Regulations: Excise Taxes on Highway Fuels," p. 25, web site www.eia.doe.gov/oiaf/archive/aeo07.
15. U.S. Department of the Treasury, Internal Revenue Service, *Excise Taxes for 2007*, Publication 510 (1/2007) (Washington, DC, Revised January 2007), web site www.irs.gov/publications/p510.
16. Defense Energy Support Center, "Compilation of United States Fuel Taxes, Inspection Fees, and Environmental Taxes and Fees" (June 29, 2007).
17. U.S. Department of Energy, Energy Efficiency and Renewable Energy, Alternative Fuels & Advanced Vehicles Data Center, "Volumetric Ethanol Excise Tax Credit (VEETC)," web site www.eere.energy.gov/afdc/progs/view_ind_fed.php/afdc/399/0.
18. E85 is a fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume.
19. VEETC was established by the American Jobs Creation Act of 2004, Section 301. Before VEETC, gasoline blended with 5.7 percent, 7.7 percent, or 10 percent ethanol received an excise tax reduction equivalent to 51 cents per gallon of ethanol; however, the applicable excise tax reduction for blends with any other ethanol percentage was equivalent to less than 51 cents per gallon of ethanol. This was an especially serious impediment to blenders of E85.
20. VEETC provided biodiesel tax credits for 2005 and 2006. EPACT2005, Section 1344, extended the biodiesel tax credits through 2007 and 2008.
21. The Food, Conservation, and Energy Act of 2008 (Public Law 110-234), which was enacted in May 2008, contains several tax provisions related to biofuels. The bill reduces the ethanol blending tax credit from 51 cents to 45 cents per gallon once annual ethanol production or import volumes reach 7.5 billion gallons; extends the ethanol import tariff through 2010; and establishes a tax credit for cellulosic biofuels of up to $1.01 per gallon produced. The *AEO2008* reference case projects ethanol production of 8.5 billion gallons in 2008, which would trigger the blending tax credit reduction in 2009. *AEO2008* does not include consideration of the Food, Conservation, and Energy Act of 2008, which was enacted too late for inclusion.
22. EPACT2005, Section 1347, increased the production volume for small producers from 30 million to 60 million gallons, starting in 2006.
23. Most of the data cited in this section are taken from U.S. Environmental Protection Agency, 40 CFR Parts 59, 80, 85, and 86, "Control of Hazardous Air Pollutants From Mobile Sources; Final Rule," *Federal Register*, Vol. 72, No. 37 (February 26, 2007), pp. 8428-8570, web site http://edocket.access.gpo.gov/2007/pdf/E7-2667.pdf.
24. The subsidy cost—essentially the expected cost of the program, excluding administrative expenditures—generally equals the amount of the loan multiplied by the probability of default. The actual computation of the "subsidy cost" and whether it represents the true cost of the program are complex issues far beyond the scope of this section of *AEO2008*. For more details on government loan guarantee programs, see Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 2007*, SR/CNEAF/2008-01 (Washington, DC, April 2008), web site www.eia.doe.gov/oiaf/servicerpt/subsidy2/index.html.
25. Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007), "Loan Guarantees and the Economics of Electricity Generating Technologies," pp. 48-49,

web site www.eia.doe.gov/oiaf/archive/aeo07/pdf/issues.pdf.

26. U.S. House of Representatives, 110th Congress, "Energy and Water Development Appropriations Bill, 2008" (House Report 110-185, June 11, 2007); and U.S. Senate, 110th Congress, "Energy and Water Appropriations Bill, 2008" (Senate Report 110-127, July 9, 2007), web site www.access.gpo.gov/congress/legislation/08appro.html.
27. See, for example, testimony of Christopher Crane, Senior Vice President, Exelon Corporation, and President and Chief Nuclear Officer, Exelon Nuclear, before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, U.S. House of Representatives (April 24, 2007), web site http://energycommerce.house.gov/cmte_mtgs/110-eaq-hrg.042407.Crane-testimony.pdf.
28. U.S. Department of Energy, Loan Guarantee Program, "DOE Releases Information on Loan Guarantee Pre-Applications" (March 6, 2007), web site www.lgprogram.energy.gov/press/030607.html.
29. Energy Information Administration, *Annual Energy Outlook 2005*, DOE/EIA-0383(2005) (Washington, DC, February 2005), "State Renewable Energy Requirements and Goals: Status Through 2003," pp. 20-22, web site www.eia.doe.gov/oiaf/archive/aeo05/leg_reg.html.
30. Energy Information Administration, *Annual Energy Outlook 2006*, DOE/EIA-0383(2006) (Washington, DC, February 2006), "State Renewable Energy Requirements and Goals: Update Through 2005," pp. 24-27, web site www.eia.doe.gov/oiaf/archive/aeo06/leg_reg.html.
31. Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007), "State Renewable Energy Requirements and Goals: Update Through 2006," pp. 28-30, web site www.eia.doe.gov/oiaf/archive/aeo07/leg_reg.html.
32. State of New Hampshire, H.B. 873, web site www.gencourt.state.nh.us/legislation/2007/HB0873.html.
33. General Assembly of North Carolina, S.B. 3, web site www.ncleg.net/Sessions/2007/Bills/Senate/PDF/S3v6.pdf.
34. Oregon Legislative Assembly, S.B. 838, signed into law by Governor Theodore R. Kulongoski on June 6, 2007, defines a large supplier as any generator that provides at least 3 percent of the State's electric load, a medium-sized supplier as one that provides between 1.5 and 3 percent of the State's load, and a small supplier as one that provides less than 1.5 percent of the State's load. See web site www.oregon.gov/ENERGY/RENEW/docs/sb0838.en.pdf.
35. Revised Code of Washington, Chapter 19.285, web site http://apps.leg.wa.gov/RCW/default.aspx?cite=19.285.
36. State of Delaware, S.B. 19, web site http://depsc.delaware.gov/electric/delrps.shtml.
37. An alternative compliance payment is a payment to the State for not meeting their renewable energy goal. In some instances, there are different compliance payments (or penalties) for unique generation technologies.
38. State of Colorado, H.B. 07-1281, web site www.leg.state.co.us/clics/clics2007a/csl.nsf/fsbillcont3/C9B0B62160D242CA87257251007C4F7A?open&file=1281_enr.pdf.
39. State of Connecticut, House Bill 7432, Public Act 07-242, web site www.cga.ct.gov/2007/ACT/PA/2007PA-00242-R00HB-07432-PA.htm.
40. State of Illinois, Public Act 095-0481, web site www.ilga.gov/legislation/publicacts/95/PDF/095-0481.pdf.
41. "Minnesota - Renewable Portfolio Standard," web site www.dsireusa.org/library/includes/tabsrch.cfm?state=MN0type=RPS&CurrentPageID=7&EE=1&RE=1.
42. U.S. Environmental Protection Agency, "Clean Air Interstate Rule," web site www.epa.gov/cair.
43. U.S. Environmental Protection Agency, "Clean Air Mercury Rule," web site www.epa.gov/camr.
44. *AEO2007* included a summary of the RGGI provisions in the original model rule. See Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007), "State Regulations on Airborne Emissions: Update Through 2006," pp. 30-32, web site www.eia.doe.gov/oiaf/archive/aeo07/leg_reg.html.
45. State of California, "Senate Bill 1368," web site www.energy.ca.gov/ghgstandards/documents/sb_1368_bill_20060929_chaptered.pdf.
46. California Environmental Protection Agency, Air Resources Board, "Proposed Regulations to Control Greenhouse Gas Emissions from Motor Vehicles," web site www.arb.ca.gov/regact/grnhsgas/grnhsgas.htm (September 19, 2005).
47. State of California, "Assembly Bill No. 1493," web site www.calcleancars.org/ab1493.pdf.
48. U.S. Environmental Protection Agency, "California Greenhouse-Gas Waiver Request," web site www.epa.gov/otaq/ca-waiver.htm.
49. Office of the New York State Attorney General Andrew M. Cuomo, "Cuomo Leads Coalition of 15 States Against EPA in Battle for States' Right To Fight Global Warming" (January 2, 2008), web site www.oag.state.ny.us/press/2008/jan/jan02a_08.html.
50. State of Washington, "Mitigating the impacts of climate change," SB 6001 – 2007-08, web site http://apps.leg.wa.gov/billinfo/summary.aspx?bill=6001.
51. State of Montana, House Bill No. 25, web site http://data.opi.mt.gov/bills/2007/billpdf/HB0025.pdf.
52. State of Florida, Executive Order 07-126, "Leadership by Example: Immediate Actions to Reduce Greenhouse Gas Emissions from Florida State Government"; Executive Order 07-127, "Immediate Actions to Reduce Greenhouse Gas Emissions within Florida"; and Executive Order 07-128, "Florida Governor's Action Team on Energy and Climate Change"; web site www.dep.state.fl.us/climatechange/eo.htm.

Issues in Focus

53. M.L. Wald, "Costs Surge for Building Power Plants," *New York Times* (July 10, 2007), web site www.nytimes.com/2007/07/10/business/worldbusiness/10energy.html.
54. Imperial Oil Resources Ventures, Ltd., "Mackenzie Gas Project: Supplemental Information Project Update," National Energy Board Submission IPRCC. PR.07.08 (Calgary, Alberta, Canada, May 2007).
55. Rising oil prices do not necessarily lead to rising oil production from existing fields. Reservoir characteristics and the properties of the oil in the reservoirs primarily determine the maximum efficient recovery rate for a particular oil reservoir. Aggregate incremental rates of improvement in oil recovery diminish rapidly as oil prices rise. For example, a recent analysis of Alaska's North Slope oil fields indicates that very little incremental recovery is achievable once oil prices exceed $60 per barrel. See National Energy Technology Laboratory, Arctic Energy Office, *Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline? Summary Report*, DOE/NETL-2007/1280 (Fairbanks, AK, August 2007), web site www.netl.doe.gov/technologies/oil-gas/publications/EPreports/ANSSummaryReportFinalAugust2007.pdf. Technological progress is more likely to affect the ultimate oil recovery rate than oil prices or drilling costs.
56. Production began in 2000 at the Alpine Field, which has an estimated ultimate recoverable reserve of about 540 million barrels. Source: National Energy Technology Laboratory, *Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline? Summary Report*, DOE/NETL-2007/1280.
57. A higher or lower level of future U.S. oil industry activity primarily affects the rate at which future U.S. oil production declines. High levels of activity can stabilize oil production for an extended period of time, especially through the application of EOR techniques, but eventually the depletion of the resource base causes production to decline. Lower levels of activity accelerate the rate of decline in future oil production.
58. Oil production in the shallow waters of the Gulf of Mexico declines slowly in all the cases.
59. The reference case assumes that pipelines from Canada and Alaska will be connected to natural gas markets in the lower 48 States. If no Arctic pipelines were built, however, there would be no pipeline to move natural gas from Alaska's North Slope to southern Alaska, where it would otherwise be converted to LNG and shipped to foreign and domestic customers. As an alternative, natural gas from the North Slope could be converted to petroleum liquids and transported through the existing Alyeska oil pipelines (also known as the TransAlaska Pipeline System).
60. Net LNG imports are slightly lower than gross LNG imports before 2011, because LNG exports to Japan from Alaska are expected to continue through 2011, at about 65 billion cubic feet per year.
61. U.S. Geological Survey, "USGS National Assessment of Oil and Gas Resources Update (December, 2006)," web site http://certmapper.cr.usgs.gov/data/noga00/natl/tabular/total.xls. The estimates cited in this discussion are rough approximations. The actual probability spread of the estimates is considerably larger.
62. If LNG imports into Canada and Mexico were constrained to the same degree as assumed for the lower 48 States, natural gas prices would be even higher, causing both a larger decrease in domestic natural gas consumption and a larger increase in lower 48 production.
63. CERA Advisory Service, "Monthly Natural Gas Briefing" (April 20, 2007).
64. NOAA Webcast, "Improving Climate Normals" (September 26, 2007).
65. A small amount of the difference is due to the use of dynamic population weights in *AEO2008*.
66. James T. Jensen of Jensen Associates in Weston, MA, stated in a presentation on "Increasing Global LNG Investments" to the LNG North America Summit 2007 in Houston, TX, June 20, 2007, that, "At the turn of the decade, LNG plant construction costs were approaching $200/ton of capacity but current costs are a multiple of that level and there have been several 'problem trains' that have been quoted at $1,200/ton and above."
67. Zeus Development Corporation of Houston, TX, has reported that costs for the Gros Cacouna terminal on the St. Lawrence River have nearly doubled from initial estimates and that the terminal is being put on hold while cost-cutting options to reduce costs to under $1 billion are studied. See "Spiraling Costs Impact Petro-Canada's LNG Terminal, Delay Decision," *LNG Express* (August 1, 2007), web site www.lngexpress.com (subscription site).
68. According to Keith Bainbridge of London-based LNG Shipping Solutions, the price of a standard sized ship, estimated at around $155 million in late 2003, has risen to between $215 and $230 million in 2007.
69. Wood Mackenzie Research and Consulting, "Global LNG Online," web site www.woodmacresearch.com/cgi-bin/wmprod/portal/energy/productMicrosite.jsp?productOID=664070 (available to subscribers only).
70. Energy Information Administration, *International Energy Outlook 2007*, DOE/EIA-0484(2007) (Washington, DC, May 2007), web site www.eia.doe.gov/oiaf/ieo.
71. Japan, South Korea, Spain, United States, France, Turkey, Belgium, United Kingdom, Italy, Mexico, Portugal, and Greece.
72. Taiwan, India, China, Puerto Rico, and Dominican Republic.
73. Indonesia, Malaysia, Qatar, Algeria, Trinidad and Tobago, Nigeria, Oman, Brunei, United Arab Emirates, Egypt, and Libya.
74. Embassy of the United States, Jakarta, Indonesia, *Country Commercial Guide – Indonesia Fiscal Year 2003*, Chapter 7, "Investment Climate Statement," p. 61, web site www.usembassyjakarta.org/ccg/ccg.html.
75. Government of Western Australia, Department of the Premier and Cabinet, *WA Government Policy on Securing Domestic Gas Supplies* (October 2006), web site www.doir.wa.gov.au/documents/DomGas_Policy(1).pdf.
76. Gas Infrastructure Europe's "Storage Investment Database" for November 2007 listed new storage projects

in Europe with a total of 1.47 trillion cubic feet of working capacity—including 0.96 trillion cubic feet in OECD countries—that had planned operational dates before 2016 and were designated as either aquifer or depleted reservoir types (commonly used for seasonal storage). The database included projects placed in operation after June 2007, under construction, committed (evaluated by the company with detailed studies and possibly undergoing planning and permitting stages), or planned (at an early evaluation stage). Four types of capacity were included: aquifer, LNG peak shaving, reservoir, and salt cavity. See Gas Infrastructure Europe, "Storage Investment Database," web site www.gie.eu.com/maps_data/database.html.

77. BG Group, "BG Group Finalises Agreement To Meet Natural Gas Demand in Chile," Press Release (June 4, 2007), web site www.bg-group.com/MediaCentre/PressArchive/2007/Pages/060407-sx.aspx.

Market Trends

78. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.
79. This change in methodology is discussed in the Issues In Focus section, pages 44-46.
80. A Divisia index is used for this calculation. A discussion of the index can be found in G. Boyd, J.F. McDonald, M. Ross, and D.A. Hansont, "Separating the Changing Composition of U.S. Manufacturing Production from Energy Efficiency Improvements: A Divisia Index Approach," *Energy Journal*, Vol. 8, No. 2 (1987).
81. S.C. Davis and S.W. Diegel, *Transportation Energy Data Book: Edition 25*, ORNL-6974 (Oak Ridge, TN, May 2006), Chapter 4, "Light Vehicles and Characteristics," web site http://cta.ornl.gov/data/chapter4.shtml.
82. The fuel shares are calculated in terms of energy content. Because of the differences in energy content per gallon of gasoline, diesel, and ethanol, the percentage share would be different on a volumetric basis. For example, it takes about 1.3 gallons of E85 to replace the energy in 1 gallon of gasoline.
83. Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and CHP capacity. Costs reflect the average of regional costs, except for wind, which uses a representative region.
84. Does not include off-grid PV. Based on annual PV shipments from 1989 through 2005, EIA estimates that as much as 192 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2005, plus an additional 481 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 10.8 (annual PV shipments, 1989-2005). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
85. Previous *AEOs* did not consider State RPS requirements.
86. Wind capacity is more than double the 2030 level projected in *AEO2007*.
87. Imperial Oil Resources Ventures, Ltd., "Mackenzie Gas Project: Supplemental Information Project Update," National Energy Board Submission IPRCC. PR.07.08 (Calgary, Alberta, Canada, May 2007).
88. CAIR mandates SO_2 emissions caps in 28 eastern and midwestern States and the District of Columbia. The first compliance period begins in 2010, and a second, more stringent cap takes effect in 2015.
89. The first milestone for reducing NO_x emissions from electric power generation becomes effective in 2009. A lower limit is mandated for 2015.

Comparison with Other Projections

90. *AEO2008* also includes the CAMR regulations. On February 8, 2008, the U.S. Court of Appeals found CAMR to be unlawful and voided it, ruling that the EPA had not proved that mercury was a pollutant eligible for regulation under a less stringent portion of the Clean Air Act; however, EIA did not have time to revise *AEO2008* before publication to remove the impact of CAMR.
91. Although neither EVA nor GII provided projections for coal consumption at CTL plants, the lack of growth in coal consumption in non-electricity sectors indicates that this technology is either not represented explicitly by the models or, alternatively, that very little CTL capacity is projected to come on line.

Table Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and D of this report.

Table 1. Total energy supply and disposition in the *AEO2008* and *AEO2007* reference cases, 2006-2030: ***AEO2007*:** AEO2007 National Energy Modeling System, run AEO2007.D112106A. ***AEO2008*:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **Notes:** Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity.

Table 2. Representative efficiency standards for enclosed motors: National Electrical Manufacturers Association, *NEMA Summary and Analysis of Energy Independence and Securrity Act of 2007*, Appendix II, Section 313—Electrical Motor Efficiency, web site www.nema.org/gov/energy/upload/NEMA-Summary-and-Analysis-of-the-Energy-Independence-and-Security-Act-of-2007.pdf.

Table 3. Summary of DOE's August 2006 loan guarantee solicitation: U.S. Department of Energy, *DOE Releases Information on Loan Guarantee Pre-Applications*

(March 6, 2007), web site www.lgprogram.energy.gov/press/030607.html.

Table 4. State renewable portfolio standards: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 5. Key analyses from "Issues in Focus" in recent *AEOs*: Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007); Energy Information Administration, *Annual Energy Outlook 2006*, DOE/EIA-0383(2006) (Washington, DC, February 2006); Energy Information Administration, *Annual Energy Outlook 2005*, DOE/EIA-0383 (2005) (Washington, DC, February 2005).

Table 6. Costs of producing electricity from new plants, 2015 and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and D of this report.

Figure 1. Energy prices, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A1.

Figure 2. Delivered energy consumption by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A2.

Figure 3. Energy consumption by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Tables A1 and A17.

Figure 4. Energy use per capita and per dollar of gross domestic product, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections: Energy use per capita:** Calculated from data in Table A2. **Energy use per dollar of GDP:** Table A19.

Figure 5. Total energy production and consumption, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A1.

Figure 6. Energy production by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Tables A1 and A17.

Figure 7. Electricity generation by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A8.

Figure 8. U.S. carbon dioxide emissions by sector and fuel, 1990-2030: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** Table A18.

Figure 9. Changes in construction commodity costs, 1973-2007: U.S. Department of Labor, Bureau of Labor Statistics, Producer Price Index for WPU112 (construction), WPU101 (iron and steel), WPU133 (concrete), and WPU1322 (cement).

Figure 10. Changes in construction commodity costs and electric utility construction costs, 1973-2007: *Handy-Whitman Bulletin*, No. 165, "Cost Trends of Electric Utility Construction"; and U.S. Department of Labor, Bureau of Labor Statistics, Producer Price Index, Series ID WPU112.

Figure 11. Additions to U.S. electricity generation capacity by fuel in three cases, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LC2008.D030308A, and HC2008.D030308A.

Figure 12. U.S. natural gas supply by source in three cases, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LC2008.D030308A, and HC2008.D030308A.

Figure 13. U.S. natural gas consumption by sector in three cases, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LC2008.D030308A, and HC2008.D030308A.

Figure 14. U.S. natural gas prices in three cases, 2000-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LC2008.D030308A, and HC2008.D030308A.

Figure 15. Electricity generation by fuel in four cases, 2006 and 2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 16. New generating capacity additions in four cases, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 17. Natural gas consumption by sector in four cases, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 18. Natural gas supply by source in four cases, 2006 and 2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 19. Lower 48 wellhead natural gas prices in four cases, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 20. U.S. average electricity prices in four cases, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F,

HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 21. Annual heating and cooling degree-days, 1993-2007: Energy Information Administration, Short-Term Energy Outlook On-Line Table Browser (February 26, 2007).

Figure 22. Heating and cooling degree-days in the *AEO2008* reference case, 2010-2030: National Energy Modeling System runs AEO2008.D030208F and WEATHER.D030408A, based on weather data from NOAA and State population projections from the Census Bureau.

Figure 23. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on energy use for heating and cooling in buildings by fuel type, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F and WEATHER.D030408A.

Figure 24. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on peak seasonal electricity demand load, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F and WEATHER.D030408A.

Figure 25. U.S. imports of liquefied natural gas, 2001-2007: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007).

Figure 26. OECD Europe natural gas supply by source, 2000-2007: International Energy Agency, Monthly Gas Data Service.

Figure 27. Gross U.S. imports of liquefied natural gas in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LOLNG08.D030508A, and HILNG08.D030508A.

Figure 28. U.S. natural gas supply in three cases, 2006-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LOLNG08.D030508A, and HILNG08.D030508A.

Figure 29. Lower 48 wellhead natural gas prices in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LOLNG08.D030508A, and HILNG08.D030508A.

Figure 30. World oil price in six cases, 2000-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LP2008.D031608A, HP2008.D031808A, AEO2007.D112106A, LP2007.D112106A, and HP2008.D112106A.

Figure 31. World liquids consumption in the *AEO2008* reference case, 2006-2030: Table A20.

Figure 32. Average annual growth rates of real GDP, labor force, and productivity, 2006-2030: Table B4.

Figure 33. Average annual inflation, interest, and unemployment rates, 2006-2030: Table B4.

Figure 34. Sectoral composition of industrial output growth rates, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 35. Energy expenditures in the U.S. economy, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 36. Energy expenditures as share of gross domestic product, 1970-2030: History: U.S. Department of Commerce, Bureau of Economic Analysis; and Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 37. World oil prices, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table C1.

Figure 38. Unconventional resources as a share of the world liquids market, 1990-2030: History: Derived from Energy Information Administration, *International Energy Annual 2005* (June-October 2007), Table G.4, web site www.eia.doe.gov/iea. **Projections:** Table A20. **Note:** Data from Table G.4 are used as a proxy for historical unconventional oil production, because international data are limited. In addition, estimates of historical production from Canadian oil sands and Venezuelan ultra-heavy oil were added to Table G.4. Assumptions about future unconventional oil production are based on current investment reports, published production targets, resource availabilities, and marketplace competition.

Figure 39. World liquids production shares by region, 2006 and 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, and LP2008.D031608A.

Figure 40. Energy use per capita and per dollar of gross domestic product, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections: Energy use per capita:** Calculated from data in Table A2. **Energy use per dollar of GDP:** Table A19.

Figure 41. Primary energy use by fuel, 2006-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Tables A1 and A17.

Figure 42. Delivered energy use by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A2.

Figure 43. Primary energy consumption by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A2.

Figure 44. Residential delivered energy consumption per capita, 1990-2030: History: Energy Information Administration, "State Energy Consumption, Price, and Expenditure Estimates (SEDS)," (Washington, DC, October 2007), web site www.eia.doe.gov/emeu/states/_seds.html, and *Annual Energy Review 2006*, DOE/EIA-0384

(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, BLDFRZN.D030408A, and BLDHIGH.D030408A.

Figure 45. Residential delivered energy consumption by fuel, 2006, 2015, and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 46. Efficiency gains for selected residential appliances, 2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004); and AEO2008 National Energy Modeling System, runs AEO2008.D030208F, BLDFRZN.D030408A, and BLDBEST.D030408A.

Figure 47. Electricity consumption for residential lighting, 2006-2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004); and AEO2008 National Energy Modeling System, runs AEO2008.D030208F and AEO2008.D112607A.

Figure 48. Commercial delivered energy consumption per capita, 1980-2030: History: Energy Information Administration, "State Energy Consumption, Price, and Expenditure Estimates (SEDS)" (Washington, DC, October 2007), web site www.eia.doe.gov/emeu/states/_seds.html, and *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, BLDFRZN.D030408A, and BLDHIGH.D030408A.

Figure 49. Commercial delivered energy consumption by fuel, 2006, 2015, and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 50. Efficiency gains for selected commercial equipment, 2006 and 2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004); and AEO2008 National Energy Modeling System, runs AEO2008.D030208F, BLDFRZN.D030408A, and BLDBEST.D030408A.

Figure 51. Industrial delivered energy consumption, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 52. Industrial energy consumption by fuel, 2000, 2006, and 2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 53. Average growth in value of shipments for the manufacturing subsectors, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 54. Average growth of delivered energy consumption in the manufacturing subsectors, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 55. Industrial delivered energy intensity, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007); and Global Insight, Inc., *2007 U.S. Energy Outlook* (November 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, INDFRZN.D030608A, and INDHIGH.D032208A.

Figure 56. Delivered energy consumption for transportation, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** Tables B2 and C2.

Figure 57. Average fuel economy of new light-duty vehicles, 1980-2030: History: U.S. Department of Transportation, National Highway Traffic Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2006), web site www.nhtsa.dot.gov/staticfiles/DOT/NHTSA/Vehicle%20Safety/Articles/Associated%20Files/SummaryFuelEconomyPerformance-2006.pdf. **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, AEO2008.D112607A, TRNHIGH.D031408A, HP2008.D031808A, and LP2008.D031608A.

Figure 58. Sales of unconventional light-duty vehicles by fuel type, 2006 and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 59. Energy use for light-duty vehicles by fuel type, 2006 and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 60. Annual electricity sales by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A8.

Figure 61. Electricity generation by fuel, 2006 and 2030: Table A8.

Figure 62. Electricity generation capacity additions by fuel type, including combined heat and power, 2007-2030: Table A9.

Figure 63. Levelized electricity costs for new plants, 2015 and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 64. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2007-2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 65. Electricity generation from nuclear power, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, LM2008.D031608A, HP2008.D031808A, and LP2008.D031608A.

Figure 66. Nonhydroelectric renewable electricity generation by energy source, 2006-2030: Table A16.

Figure 67. Grid-connected electricity generation from renewable energy sources, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A16.

Figure 68. Levelized and avoided costs for new renewable plants in the Northwest, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIRENCST08.D030408A, and LORENCST08.D030408A.

Figure 69. Regional growth in nonhydroelectic renewable electricity generation, 2006-2030: AEO2008 National Energy Modeling System, run AEO2008. D030208F.

Figure 70. Fuel prices to electricity generators, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 71. Average U.S. retail electricity prices, 1970-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A8.

Figure 72. Natural gas consumption by sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2004) (Washington, DC, June 2007). **Projections:** Table A13.

Figure 73. Total natural gas consumption, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, LP2008.D031608A, HM2008. D031608A, and LM2008.D031608A.

Figure 74. Natural gas consumption in the electric power and non-electric power sectors in alternative price cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, and LP2008. D031608A.

Figure 75. Natural gas consumption in the electric power and non-electric power sectors in alternative growth cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008. D031608A.

Figure 76. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030: History: For lower 48 wellhead prices: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). For Henry Hub natural gas prices: Energy Information Administration, *Short-Term Energy Outlook* Query System, Monthly Natural Gas Data, Variable NGHHMCF. **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 77. Lower 48 wellhead natural gas prices, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, LP2008.D031608A, OGHTEC08. D030508A, and OGLTEC08.D030508A.

Figure 78. Natural gas prices by end-use sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A13.

Figure 79. Average natural gas transmission and distribution margins, 1990-2030: History: Calculated as the difference between natural gas end-use prices and lower 48 wellhead natural gas prices; Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008. D030208F, HP2008.D031808A, and LP2008.D031608A.

Figure 80. Natural gas production by source, 1990-2030: History: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** Table A14.

Figure 81. Total U.S. natural gas production, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, LP2008.D031608A, OGHTEC08. D030508A, and OGLTEC08.D030508A.

Figure 82. Net U.S. imports of natural gas by source, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 83. Net U.S. imports of liquefied natural gas, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, LP2008.D031608A, HM2008. D031608A, and LM2008.D031608A.

Figure 84. Domestic crude oil production by source, 1990-2030: History: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 85. Total U.S. crude oil production, 1990-2030: History: Energy Information Administration, Annual Energy Review 2006, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, OGHTEC08.D030508A, and OGLTEC08.D030508A.

Figure 86. Total U.S. unconventional crude oil production, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, and LP2008.D031608A.

Figure 87. Liquid fuels consumption by sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A11.

Figure 88. EISA2007 RFS credits earned in selected years, 2006-2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 89. Fossil fuel and biofuel content of U.S. motor fuel supply, 2006, 2015, and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 90. Net import share of U.S. liquid fuels consumption, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384

(2006) (Washington, DC, June 2007). **Projections:** Table C4.

Figure 91. Motor gasoline, diesel fuel, and E85 prices, 2006-2030: Table A12.

Figure 92. Average U.S. delivered prices for motor gasoline, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** Table C5.

Figure 93. Coal production by region, 1970-2030: History (short tons): 1970-1990: Energy Information Administration (EIA), *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** EIA, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2006:** EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, October 2007), and previous issues. **History: Conversion to quadrillion Btu), 1970-2006:** Estimation Procedure: EIA, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year are based on coal quality data for 2006, collected in various energy surveys (see sources), and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Annual Energy Review*. **Sources:** EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **Note:** For 1989-2030, coal production includes waste coal.

Figure 94. U.S. coal production, 2006, 2015, and 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LP2008.D031608A, HP2008.D031808A, LM2008.D031608A, HM2008.D031608A, LCCST08.D030508A, and HCCST08.D030508A. **Note:** Coal production includes waste coal.

Figure 95. Average minemouth price of coal by region, 1990-2030: History: Dollars per short ton: 1990-2000: Energy Information Administration (EIA), *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2006:** EIA, *Annual Coal Report 2006*, DOE/EIA-0584 (2006) (Washington, DC, October 2007), and previous issues. **Conversion to dollars per million Btu): 1990-2006:** Estimation Procedure: EIA, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year are based on coal quality data for 2006, collected in various energy surveys (see sources), and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Annual Energy Review*. **Sources:** EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **Note:** Includes reported prices for both open market and captive mines.

Figure 96. Average delivered coal prices, 1990-2030: History: Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121 (2006/4Q) (Washington, DC, March 2007), and previous issues; EIA, *Electric Power Monthly*, October 2007, DOE/EIA-0226(2007/10) (Washington, DC, October 2007); and EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LP2008.D031608A, HP2008.D031808A, LCCST08.D030508A, and HCCST08.D030508A. **Note:** Historical prices are weighted by consumption but exclude residential/commercial prices and export free-alongside-ship (f.a.s.) prices.

Figure 97. Carbon dioxide emissions by sector and fuel, 2006 and 2030: 2006: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **2030:** Table A18.

Figure 98. Carbon dioxide emissions, 1990-2030: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** Table B2.

Figure 99. Sulfur dioxide emissions from electricity generation, 1995-2030: History: 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000). **2000:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2006 and Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 100. Nitrogen oxide emissions from electricity generation, 1995-2030: History: 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000). **2000:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2006 and Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Appendixes

Table A1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Production								
Crude Oil and Lease Condensate	10.99	10.80	12.76	13.25	13.40	12.99	12.04	0.5%
Natural Gas Plant Liquids	2.33	2.36	2.27	2.29	2.31	2.17	2.11	-0.5%
Dry Natural Gas	18.60	19.04	19.85	20.08	20.24	20.17	20.00	0.2%
Coal[1]	23.19	23.79	23.97	24.48	25.20	26.85	28.63	0.8%
Nuclear Power	8.16	8.21	8.31	8.41	9.05	9.50	9.57	0.6%
Hydropower	2.70	2.89	2.92	2.99	3.00	3.00	3.00	0.2%
Biomass[2]	2.79	2.94	4.05	5.12	6.42	8.00	8.12	4.3%
Other Renewable Energy[3]	0.67	0.88	1.51	1.75	2.00	2.25	2.45	4.4%
Other[4]	0.36	0.50	0.54	0.58	0.58	0.61	0.64	1.1%
Total	**69.80**	**71.41**	**76.17**	**78.96**	**82.21**	**85.53**	**86.56**	**0.8%**
Imports								
Crude Oil	22.09	22.08	21.14	21.80	21.58	22.38	24.41	0.4%
Liquid Fuels and Other Petroleum[5]	7.23	7.21	5.61	5.34	5.43	5.28	5.44	-1.2%
Natural Gas	4.45	4.29	4.80	5.12	4.68	4.63	4.64	0.3%
Other Imports[6]	0.85	0.98	0.95	1.04	1.93	2.23	2.74	4.4%
Total	**34.62**	**34.57**	**32.49**	**33.31**	**33.62**	**34.52**	**37.22**	**0.3%**
Exports								
Petroleum[7]	2.32	2.60	2.82	2.91	2.98	3.17	3.33	1.0%
Natural Gas	0.74	0.73	0.84	0.97	1.02	1.25	1.36	2.6%
Coal	1.27	1.26	1.79	1.14	0.87	0.90	0.88	-1.5%
Total	**4.32**	**4.59**	**5.45**	**5.03**	**4.87**	**5.32**	**5.56**	**0.8%**
Discrepancy[8]	**0.01**	**1.87**	**-0.13**	**-0.01**	**0.12**	**0.19**	**0.21**	**--**
Consumption								
Liquid Fuels and Other Petroleum[9]	40.47	40.06	40.46	41.80	42.24	42.78	43.99	0.4%
Natural Gas	22.65	22.30	23.93	24.35	24.01	23.66	23.39	0.2%
Coal[10]	22.78	22.50	23.03	24.19	25.87	27.75	29.90	1.2%
Nuclear Power	8.16	8.21	8.31	8.41	9.05	9.50	9.57	0.6%
Hydropower	2.70	2.89	2.92	2.99	3.00	3.00	3.00	0.2%
Biomass[11]	2.45	2.50	3.01	3.60	4.50	5.42	5.51	3.3%
Other Renewable Energy[3]	0.67	0.88	1.51	1.75	2.00	2.25	2.45	4.4%
Other[12]	0.21	0.19	0.18	0.17	0.17	0.18	0.20	0.3%
Total	**100.08**	**99.52**	**103.34**	**107.26**	**110.85**	**114.54**	**118.01**	**0.7%**

Table A1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Prices (2006 dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price	58.28	66.02	74.03	59.85	59.70	64.49	70.45	0.3%
Imported Crude Oil Price[13]	50.40	59.05	65.18	52.03	51.55	55.68	58.66	-0.0%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	8.93	6.73	6.90	5.87	5.95	6.39	7.22	0.3%
Wellhead Price[14]	7.62	6.24	6.16	5.21	5.29	5.69	6.45	0.1%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	7.85	6.42	6.33	5.36	5.44	5.86	6.63	0.1%
Coal (dollars per ton)								
Minemouth Price[15]	24.08	24.63	26.16	23.38	22.51	22.75	23.32	-0.2%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.18	1.21	1.28	1.17	1.14	1.16	1.19	-0.1%
Average Delivered Price[16]	1.67	1.78	1.93	1.80	1.77	1.78	1.82	0.1%
Average Electricity Price (cents per kilowatthour)	8.4	8.9	9.2	8.5	8.6	8.7	8.8	-0.0%

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol, biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 natural gas wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2005 and 2006 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values and 2005 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). Other 2005 petroleum supply values: EIA, *Petroleum Supply Annual 2005*, DOE/EIA-0340(2005)/1 (Washington, DC, October 2006). 2005 and 2006 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2005 and 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2005 and 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Energy Consumption								
Residential								
Liquefied Petroleum Gases	0.50	0.47	0.48	0.50	0.52	0.54	0.55	0.7%
Kerosene	0.09	0.07	0.08	0.08	0.08	0.08	0.08	0.5%
Distillate Fuel Oil	0.85	0.70	0.75	0.75	0.73	0.69	0.65	-0.3%
Liquid Fuels and Other Petroleum Subtotal	1.45	1.25	1.31	1.33	1.33	1.31	1.29	0.1%
Natural Gas	4.97	4.50	4.95	5.16	5.30	5.35	5.32	0.7%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.4%
Renewable Energy[1]	0.45	0.41	0.44	0.42	0.40	0.39	0.38	-0.3%
Electricity	4.64	4.61	4.95	5.02	5.25	5.53	5.88	1.0%
Delivered Energy	**11.52**	**10.77**	**11.66**	**11.95**	**12.30**	**12.58**	**12.88**	**0.7%**
Electricity Related Losses	10.12	10.04	10.59	10.61	11.08	11.57	12.14	0.8%
Total	**21.64**	**20.82**	**22.25**	**22.56**	**23.39**	**24.15**	**25.01**	**0.8%**
Commercial								
Liquefied Petroleum Gases	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.6%
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.4%
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.2%
Distillate Fuel Oil	0.45	0.42	0.38	0.41	0.41	0.42	0.41	-0.0%
Residual Fuel Oil	0.12	0.11	0.10	0.10	0.10	0.10	0.10	-0.4%
Liquid Fuels and Other Petroleum Subtotal	0.72	0.68	0.63	0.67	0.68	0.68	0.68	0.0%
Natural Gas	3.09	2.92	3.04	3.29	3.47	3.63	3.78	1.1%
Coal	0.09	0.08	0.08	0.08	0.08	0.08	0.08	-0.1%
Renewable Energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	--
Electricity	4.35	4.43	4.73	5.19	5.67	6.15	6.62	1.7%
Delivered Energy	**8.38**	**8.25**	**8.62**	**9.37**	**10.03**	**10.67**	**11.30**	**1.3%**
Electricity Related Losses	9.50	9.66	10.12	10.98	11.96	12.87	13.68	1.5%
Total	**17.87**	**17.91**	**18.74**	**20.34**	**21.98**	**23.54**	**24.98**	**1.4%**
Industrial[4]								
Liquefied Petroleum Gases	2.07	2.09	2.12	1.97	1.83	1.74	1.71	-0.8%
Motor Gasoline[2]	0.37	0.38	0.38	0.37	0.37	0.38	0.38	0.1%
Distillate Fuel Oil	1.26	1.28	1.29	1.25	1.23	1.22	1.23	-0.2%
Residual Fuel Oil	0.28	0.28	0.28	0.25	0.23	0.23	0.23	-0.9%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Other Petroleum[5]	4.39	4.48	4.25	4.30	4.22	4.25	4.41	-0.1%
Liquid Fuels and Other Petroleum Subtotal	9.79	9.92	9.67	9.60	9.27	9.15	9.25	-0.3%
Natural Gas	6.79	6.68	7.16	7.21	7.14	7.17	7.08	0.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Lease and Plant Fuel[6]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Natural Gas Subtotal	7.93	7.85	8.37	8.43	8.39	8.44	8.35	0.3%
Metallurgical Coal	0.62	0.60	0.60	0.54	0.54	0.52	0.48	-0.9%
Other Industrial Coal	1.28	1.26	1.31	1.22	1.20	1.19	1.18	-0.3%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	--
Net Coal Coke Imports	0.04	0.06	0.03	0.03	0.04	0.04	0.04	-1.8%
Coal Subtotal	1.94	1.92	1.93	1.92	2.11	2.14	2.26	0.7%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Renewable Energy[7]	1.64	1.69	1.66	1.75	1.83	1.93	2.02	0.7%
Electricity	3.48	3.42	3.50	3.61	3.59	3.55	3.52	0.1%
Delivered Energy	**25.03**	**25.10**	**25.82**	**26.31**	**26.70**	**27.50**	**27.70**	**0.4%**
Electricity Related Losses	7.59	7.45	7.50	7.63	7.57	7.43	7.28	-0.1%
Total	**32.62**	**32.55**	**33.32**	**33.93**	**34.27**	**34.93**	**34.98**	**0.3%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Transportation								
Liquefied Petroleum Gases	0.01	0.02	0.02	0.01	0.01	0.01	0.01	-1.0%
E85[8]	0.00	0.00	0.00	0.18	0.97	1.42	1.34	33.5%
Motor Gasoline[2]	17.02	17.20	17.25	17.46	16.56	15.83	15.97	-0.3%
Jet Fuel[9]	3.22	3.16	3.44	3.82	4.15	4.48	4.79	1.8%
Distillate Fuel Oil[10]	5.99	6.18	6.54	7.13	7.63	8.25	8.98	1.6%
Residual Fuel Oil	0.83	0.83	0.85	0.85	0.86	0.86	0.87	0.2%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.8%
Other Petroleum[11]	0.19	0.18	0.17	0.18	0.18	0.18	0.18	0.0%
Liquid Fuels and Other Petroleum Subtotal	27.26	27.57	28.29	29.63	30.37	31.03	32.15	0.6%
Pipeline Fuel Natural Gas	0.60	0.59	0.64	0.66	0.69	0.72	0.72	0.8%
Compressed Natural Gas	0.02	0.02	0.04	0.06	0.07	0.08	0.08	6.0%
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.03	1.3%
Delivered Energy	**27.90**	**28.20**	**28.98**	**30.37**	**31.15**	**31.86**	**32.98**	**0.7%**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.06	0.06	1.1%
Total	**27.95**	**28.25**	**29.03**	**30.42**	**31.21**	**31.92**	**33.04**	**0.7%**
Delivered Energy Consumption for All Sectors								
Liquefied Petroleum Gases	2.68	2.65	2.70	2.57	2.45	2.39	2.37	-0.5%
E85[8]	0.00	0.00	0.00	0.18	0.97	1.42	1.34	33.5%
Motor Gasoline[2]	17.44	17.62	17.68	17.89	16.99	16.26	16.40	-0.3%
Jet Fuel[9]	3.22	3.16	3.44	3.82	4.15	4.48	4.79	1.8%
Kerosene	0.14	0.11	0.12	0.12	0.13	0.13	0.13	0.4%
Distillate Fuel Oil	8.56	8.59	8.97	9.55	10.00	10.58	11.28	1.1%
Residual Fuel Oil	1.22	1.23	1.23	1.21	1.19	1.19	1.20	-0.1%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.8%
Other Petroleum[12]	4.55	4.64	4.40	4.45	4.38	4.41	4.56	-0.1%
Liquid Fuels and Other Petroleum Subtotal	39.23	39.41	39.90	41.23	41.65	42.17	43.37	0.4%
Natural Gas	14.86	14.12	15.19	15.72	15.98	16.22	16.27	0.6%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Lease and Plant Fuel[6]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Pipeline Natural Gas	0.60	0.59	0.64	0.66	0.69	0.72	0.72	0.8%
Natural Gas Subtotal	16.61	15.88	17.04	17.60	17.93	18.22	18.26	0.6%
Metallurgical Coal	0.62	0.60	0.60	0.54	0.54	0.52	0.48	-0.9%
Other Coal	1.38	1.35	1.40	1.31	1.29	1.28	1.27	-0.3%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	--
Net Coal Coke Imports	0.04	0.06	0.03	0.03	0.04	0.04	0.04	-1.8%
Coal Subtotal	2.04	2.01	2.03	2.01	2.21	2.23	2.35	0.6%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Renewable Energy[13]	2.22	2.23	2.23	2.29	2.37	2.45	2.52	0.5%
Electricity	12.49	12.49	13.20	13.85	14.54	15.26	16.05	1.1%
Delivered Energy	**72.82**	**72.32**	**75.08**	**77.99**	**80.18**	**82.61**	**84.86**	**0.7%**
Electricity Related Losses	27.26	27.19	28.26	29.27	30.67	31.93	33.16	0.8%
Total	**100.08**	**99.52**	**103.34**	**107.26**	**110.85**	**114.54**	**118.01**	**0.7%**
Electric Power[14]								
Distillate Fuel Oil	0.21	0.18	0.18	0.18	0.20	0.21	0.23	0.9%
Residual Fuel Oil	1.03	0.46	0.38	0.39	0.39	0.40	0.40	-0.6%
Liquid Fuels and Other Petroleum Subtotal	1.24	0.64	0.56	0.57	0.59	0.61	0.63	-0.1%
Natural Gas	6.04	6.42	6.89	6.75	6.09	5.45	5.13	-0.9%
Steam Coal	20.74	20.48	21.01	22.18	23.67	25.51	27.55	1.2%
Nuclear Power	8.16	8.21	8.31	8.41	9.05	9.50	9.57	0.6%
Renewable Energy[15]	3.49	3.74	4.53	5.05	5.64	5.94	6.13	2.1%
Electricity Imports	0.08	0.06	0.05	0.04	0.04	0.05	0.08	1.0%
Total[16]	**39.73**	**39.68**	**41.46**	**43.12**	**45.21**	**47.19**	**49.21**	**0.9%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Total Energy Consumption								
Liquefied Petroleum Gases	2.68	2.65	2.70	2.57	2.45	2.39	2.37	-0.5%
E85[8]	0.00	0.00	0.00	0.18	0.97	1.42	1.34	33.5%
Motor Gasoline[2]	17.44	17.62	17.68	17.89	16.99	16.26	16.40	-0.3%
Jet Fuel[9]	3.22	3.16	3.44	3.82	4.15	4.48	4.79	1.8%
Kerosene	0.14	0.11	0.12	0.12	0.13	0.13	0.13	0.4%
Distillate Fuel Oil	8.76	8.77	9.15	9.73	10.20	10.79	11.51	1.1%
Residual Fuel Oil	2.26	1.69	1.60	1.59	1.58	1.59	1.60	-0.2%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.8%
Other Petroleum[12]	4.55	4.64	4.40	4.45	4.38	4.41	4.56	-0.1%
Liquid Fuels and Other Petroleum Subtotal	40.47	40.06	40.46	41.80	42.24	42.78	43.99	0.4%
Natural Gas	20.90	20.54	22.08	22.47	22.07	21.67	21.40	0.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Lease and Plant Fuel[6]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Pipeline Natural Gas	0.60	0.59	0.64	0.66	0.69	0.72	0.72	0.8%
Natural Gas Subtotal	22.65	22.30	23.93	24.35	24.01	23.66	23.39	0.2%
Metallurgical Coal	0.62	0.60	0.60	0.54	0.54	0.52	0.48	-0.9%
Other Coal	22.12	21.83	22.41	23.49	24.96	26.79	28.82	1.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	--
Net Coal Coke Imports	0.04	0.06	0.03	0.03	0.04	0.04	0.04	-1.8%
Coal Subtotal	22.78	22.49	23.03	24.19	25.87	27.75	29.90	1.2%
Nuclear Power	8.16	8.21	8.31	8.41	9.05	9.50	9.57	0.6%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Renewable Energy[17]	5.71	5.97	6.76	7.34	8.01	8.39	8.66	1.6%
Electricity Imports	0.08	0.06	0.05	0.04	0.04	0.05	0.08	1.0%
Total	**100.08**	**99.52**	**103.34**	**107.26**	**110.85**	**114.54**	**118.01**	**0.7%**
Energy Use and Related Statistics								
Delivered Energy Use	72.82	72.32	75.08	77.99	80.18	82.61	84.86	0.7%
Total Energy Use	100.08	99.52	103.34	107.26	110.85	114.54	118.01	0.7%
Ethanol Consumed in Motor Gasoline and E85	0.34	0.47	1.05	1.34	1.82	2.06	2.01	6.2%
Population (millions)	297.34	300.13	310.85	324.29	337.74	351.41	365.59	0.8%
Gross Domestic Product (billion 2000 dollars)	11004	11319	12453	14199	15984	17951	20219	2.4%
Carbon Dioxide Emissions (million metric tons)	5981.5	5890.3	6010.6	6226.2	6384.1	6570.6	6851.0	0.6%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic and solar thermal sources. Includes petroleum coke used in the electric power sector. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
-- = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2005 and 2006 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 population and gross domestic product: Global Insight, Global Insight Industry and Employment models, July 2007. 2005 and 2006 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007).
Projections: EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A3. Energy Prices by Sector and Source
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Residential								
Liquefied Petroleum Gases	18.83	23.08	25.21	24.15	24.23	24.63	25.43	0.4%
Distillate Fuel Oil	16.98	17.94	17.21	14.27	14.27	15.14	16.27	-0.4%
Natural Gas	12.85	13.40	12.15	11.20	11.39	11.94	12.91	-0.2%
Electricity	28.52	30.52	31.37	30.04	30.20	30.33	30.63	0.0%
Commercial								
Distillate Fuel Oil	13.82	14.59	15.24	12.88	13.24	13.88	15.00	0.1%
Residual Fuel Oil	11.21	8.60	10.06	7.95	7.95	8.62	9.22	0.3%
Natural Gas	11.53	11.50	10.59	9.68	9.91	10.47	11.43	-0.0%
Electricity	26.12	27.75	27.89	25.52	25.64	25.71	26.17	-0.2%
Industrial[1]								
Liquefied Petroleum Gases	17.54	19.71	17.74	16.65	16.79	17.10	17.79	-0.4%
Distillate Fuel Oil	14.50	15.33	15.72	13.95	14.62	15.10	16.26	0.2%
Residual Fuel Oil	10.43	9.06	10.86	8.24	8.29	9.00	9.62	0.2%
Natural Gas[2]	8.37	7.66	7.21	6.15	6.21	6.56	7.29	-0.2%
Metallurgical Coal	3.29	3.54	4.07	3.53	3.42	3.51	3.60	0.1%
Other Industrial Coal	2.22	2.34	2.42	2.31	2.28	2.30	2.33	-0.0%
Coal for Liquids	--	--	--	0.96	1.09	1.17	1.30	--
Electricity	17.25	17.97	19.21	17.22	17.27	17.30	17.63	-0.1%
Transportation								
Liquefied Petroleum Gases[3]	20.49	21.72	26.03	24.93	24.94	25.28	26.03	0.8%
E85[4]	23.89	24.81	23.58	17.61	18.15	18.50	19.62	-1.0%
Motor Gasoline[5]	19.28	21.19	21.23	18.80	19.64	19.67	20.37	-0.2%
Jet Fuel[6]	13.30	14.83	15.77	13.16	13.27	14.15	15.37	0.1%
Diesel Fuel (distillate fuel oil)[7]	18.09	19.72	19.68	17.65	18.26	18.54	19.59	-0.0%
Residual Fuel Oil	8.68	7.89	10.53	8.56	8.69	9.50	10.39	1.2%
Natural Gas[8]	14.55	14.28	13.60	12.34	12.15	12.28	12.83	-0.4%
Electricity	30.79	29.73	30.95	28.95	29.05	28.95	29.65	-0.0%
Electric Power[9]								
Distillate Fuel Oil	12.62	13.35	13.62	10.67	10.69	11.59	12.71	-0.2%
Residual Fuel Oil	7.40	8.17	9.45	7.41	7.50	8.25	9.04	0.4%
Natural Gas	8.44	6.87	6.96	5.93	5.95	6.26	6.93	0.0%
Steam Coal	1.59	1.69	1.84	1.74	1.72	1.74	1.78	0.2%
Average Price to All Users[10]								
Liquefied Petroleum Gases	17.75	20.35	19.27	18.32	18.59	19.03	19.82	-0.1%
E85[4]	23.89	24.81	23.58	17.61	18.15	18.50	19.62	-1.0%
Motor Gasoline[5]	19.18	21.06	21.23	18.80	19.64	19.67	20.37	-0.1%
Jet Fuel	13.30	14.83	15.77	13.16	13.27	14.15	15.37	0.1%
Distillate Fuel Oil	17.11	18.56	18.48	16.57	17.20	17.62	18.74	0.0%
Residual Fuel Oil	8.44	8.21	10.31	8.19	8.29	9.06	9.87	0.8%
Natural Gas	9.93	9.22	8.72	7.78	7.98	8.49	9.36	0.1%
Metallurgical Coal	3.29	3.54	4.07	3.53	3.42	3.51	3.60	0.1%
Other Coal	1.63	1.73	1.88	1.77	1.75	1.77	1.81	0.2%
Coal for Liquids	--	--	--	0.96	1.09	1.17	1.30	--
Electricity	24.55	26.10	26.90	25.00	25.23	25.43	25.93	-0.0%

Table A3. Energy Prices by Sector and Source (Continued)
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Non-Renewable Energy Expenditures by Sector (billion 2006 dollars)								
Residential	221.30	225.38	241.71	232.60	243.22	256.33	274.70	0.8%
Commercial	159.35	166.54	174.38	173.76	189.37	206.24	227.37	1.3%
Industrial	203.06	205.11	224.65	197.41	193.16	194.97	203.93	-0.0%
Transportation	489.23	542.63	560.74	514.93	530.80	539.68	587.86	0.3%
Total Non-Renewable Expenditures	1072.94	1139.66	1201.48	1118.69	1156.54	1197.22	1293.86	0.5%
Transportation Renewable Expenditures	0.03	0.03	0.06	3.14	17.64	26.21	26.35	32.2%
Total Expenditures	**1072.96**	**1139.70**	**1201.54**	**1121.83**	**1174.18**	**1223.43**	**1320.22**	**0.6%**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2005 residential and commercial natural gas delivered prices: EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2006 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 and 2006 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and estimated state taxes, federal taxes, and dispensing costs or charges. 2006 transportation sector natural gas delivered prices are model results. 2005 and 2006 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2005 and 2006 coal prices based on: EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007) and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. 2005 and 2006 electricity prices: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Key Indicators								
Households (millions)								
Single-Family	79.65	80.81	83.48	88.66	93.38	97.49	101.28	0.9%
Multifamily	24.49	24.81	25.86	27.42	29.05	30.69	32.44	1.1%
Mobile Homes	6.94	6.89	6.67	6.65	6.73	6.78	6.86	-0.0%
Total	**111.09**	**112.51**	**116.00**	**122.73**	**129.15**	**134.96**	**140.58**	**0.9%**
Average House Square Footage	**1802**	**1815**	**1858**	**1916**	**1965**	**2008**	**2046**	**0.5%**
Energy Intensity								
(million Btu per household)								
Delivered Energy Consumption	103.7	95.8	100.5	97.3	95.3	93.2	91.6	-0.2%
Total Energy Consumption	194.8	185.0	191.8	183.8	181.1	179.0	177.9	-0.2%
(thousand Btu per square foot)								
Delivered Energy Consumption	57.5	52.8	54.1	50.8	48.5	46.4	44.8	-0.7%
Total Energy Consumption	108.1	101.9	103.2	95.9	92.1	89.1	87.0	-0.7%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.31	0.27	0.30	0.32	0.32	0.33	0.33	0.8%
Space Cooling	0.82	0.75	0.79	0.85	0.91	0.97	1.04	1.4%
Water Heating	0.38	0.38	0.38	0.40	0.42	0.43	0.43	0.5%
Refrigeration	0.39	0.39	0.37	0.36	0.37	0.38	0.39	0.0%
Cooking	0.10	0.10	0.11	0.12	0.12	0.13	0.14	1.2%
Clothes Dryers	0.25	0.25	0.25	0.26	0.27	0.28	0.30	0.6%
Freezers	0.08	0.08	0.08	0.08	0.09	0.10	0.11	1.3%
Lighting	0.73	0.74	0.72	0.55	0.51	0.47	0.49	-1.7%
Clothes Washers[1]	0.03	0.04	0.03	0.03	0.03	0.03	0.03	-1.1%
Dishwashers[1]	0.10	0.10	0.09	0.09	0.10	0.10	0.11	0.4%
Color Televisions and Set-Top Boxes	0.30	0.33	0.39	0.40	0.43	0.48	0.55	2.2%
Personal Computers	0.07	0.07	0.10	0.11	0.12	0.14	0.16	3.6%
Furnace Fans	0.06	0.05	0.06	0.07	0.07	0.08	0.08	1.6%
Other Uses[2]	1.01	1.05	1.26	1.37	1.49	1.61	1.73	2.1%
Delivered Energy	**4.64**	**4.61**	**4.95**	**5.02**	**5.25**	**5.53**	**5.88**	**1.0%**
Natural Gas								
Space Heating	3.59	3.13	3.57	3.73	3.83	3.87	3.88	0.9%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.1%
Water Heating	1.09	1.08	1.08	1.12	1.15	1.14	1.09	0.1%
Cooking	0.22	0.22	0.22	0.24	0.25	0.26	0.26	0.8%
Clothes Dryers	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.6%
Delivered Energy	**4.97**	**4.50**	**4.95**	**5.16**	**5.30**	**5.35**	**5.32**	**0.7%**
Distillate Fuel Oil								
Space Heating	0.75	0.60	0.66	0.66	0.65	0.62	0.59	-0.1%
Water Heating	0.11	0.10	0.09	0.09	0.08	0.08	0.07	-1.8%
Delivered Energy	**0.85**	**0.70**	**0.75**	**0.75**	**0.73**	**0.69**	**0.65**	**-0.3%**
Liquefied Petroleum Gases								
Space Heating	0.26	0.23	0.24	0.24	0.24	0.23	0.23	0.0%
Water Heating	0.06	0.06	0.05	0.05	0.05	0.04	0.04	-1.1%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.3%
Other Uses[3]	0.15	0.15	0.16	0.18	0.20	0.22	0.25	2.0%
Delivered Energy	**0.50**	**0.47**	**0.48**	**0.50**	**0.52**	**0.54**	**0.55**	**0.7%**
Marketed Renewables (wood)[4]	0.45	0.41	0.44	0.42	0.40	0.39	0.38	-0.3%
Other Fuels[5]	0.10	0.08	0.09	0.09	0.09	0.09	0.09	0.4%

Table A4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Delivered Energy Consumption by End Use								
Space Heating	5.46	4.72	5.30	5.46	5.53	5.53	5.50	0.6%
Space Cooling	0.82	0.75	0.79	0.85	0.91	0.97	1.04	1.4%
Water Heating	1.64	1.62	1.61	1.66	1.70	1.69	1.63	0.0%
Refrigeration	0.39	0.39	0.37	0.36	0.37	0.38	0.39	0.0%
Cooking	0.35	0.35	0.36	0.38	0.41	0.42	0.43	0.9%
Clothes Dryers	0.32	0.33	0.33	0.34	0.35	0.36	0.38	0.6%
Freezers	0.08	0.08	0.08	0.08	0.09	0.10	0.11	1.3%
Lighting	0.73	0.74	0.72	0.55	0.51	0.47	0.49	-1.7%
Clothes Washers	0.03	0.04	0.03	0.03	0.03	0.03	0.03	-1.1%
Dishwashers	0.10	0.10	0.09	0.09	0.10	0.10	0.11	0.4%
Color Televisions and Set-Top Boxes	0.30	0.33	0.39	0.40	0.43	0.48	0.55	2.2%
Personal Computers	0.07	0.07	0.10	0.11	0.12	0.14	0.16	3.6%
Furnace Fans	0.06	0.05	0.06	0.07	0.07	0.08	0.08	1.6%
Other Uses[5]	1.16	1.21	1.42	1.56	1.69	1.83	1.98	2.1%
Delivered Energy	**11.52**	**10.77**	**11.66**	**11.95**	**12.30**	**12.58**	**12.88**	**0.7%**
Electricity Related Losses	**10.12**	**10.04**	**10.59**	**10.61**	**11.08**	**11.57**	**12.14**	**0.8%**
Total Energy Consumption by End Use								
Space Heating	6.14	5.31	5.95	6.13	6.21	6.22	6.18	0.6%
Space Cooling	2.61	2.39	2.48	2.64	2.83	3.01	3.19	1.2%
Water Heating	2.47	2.44	2.43	2.51	2.59	2.59	2.52	0.1%
Refrigeration	1.26	1.24	1.15	1.12	1.14	1.16	1.20	-0.1%
Cooking	0.57	0.58	0.60	0.63	0.67	0.70	0.72	0.9%
Clothes Dryers	0.88	0.88	0.87	0.90	0.92	0.95	0.99	0.5%
Freezers	0.27	0.26	0.25	0.26	0.29	0.31	0.34	1.1%
Lighting	2.31	2.35	2.26	1.71	1.58	1.47	1.49	-1.9%
Clothes Washers	0.11	0.11	0.10	0.09	0.08	0.08	0.08	-1.2%
Dishwashers	0.31	0.30	0.29	0.29	0.30	0.31	0.33	0.3%
Color Televisions and Set-Top Boxes	0.95	1.05	1.23	1.26	1.33	1.49	1.69	2.0%
Personal Computers	0.21	0.21	0.30	0.34	0.38	0.43	0.48	3.5%
Furnace Fans	0.19	0.17	0.20	0.21	0.23	0.24	0.24	1.5%
Other Uses[6]	3.37	3.50	4.13	4.46	4.84	5.19	5.55	1.9%
Total	**21.64**	**20.82**	**22.25**	**22.56**	**23.39**	**24.15**	**25.01**	**0.8%**
Nonmarketed Renewables[7]								
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.01	0.01	6.1%
Solar Hot Water Heating	0.01	0.01	0.02	0.02	0.03	0.04	0.05	5.3%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.01	16.9%
Total	**0.01**	**0.02**	**0.02**	**0.03**	**0.04**	**0.05**	**0.07**	**5.9%**

[1]Does not include water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above.
[3]Includes such appliances as outdoor grills and mosquito traps.
[4]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2001.*
[5]Includes kerosene and coal.
[6]Includes all other uses listed above.
[7]Represents primary energy displaced.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Key Indicators								
Total Floorspace (billion square feet)								
Surviving	72.1	73.2	77.2	82.2	87.4	92.9	98.7	1.3%
New Additions	1.6	1.6	1.6	1.8	1.8	2.0	2.1	0.9%
Total	**73.8**	**74.8**	**78.8**	**83.9**	**89.3**	**94.8**	**100.8**	**1.2%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	113.5	110.3	109.3	111.6	112.3	112.6	112.2	0.1%
Electricity Related Losses	128.8	129.1	128.4	130.8	134.0	135.7	135.8	0.2%
Total Energy Consumption	242.3	239.4	237.8	242.4	246.3	248.3	247.9	0.1%
Delivered Energy Consumption by Fuel								
Purchased Electricity								
Space Heating[1]	0.14	0.13	0.14	0.14	0.14	0.15	0.15	0.5%
Space Cooling[1]	0.52	0.51	0.50	0.52	0.55	0.58	0.61	0.8%
Water Heating[1]	0.16	0.16	0.15	0.16	0.16	0.16	0.16	0.1%
Ventilation	0.19	0.19	0.19	0.20	0.21	0.22	0.23	0.9%
Cooking	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-0.4%
Lighting	1.16	1.15	1.12	1.17	1.22	1.28	1.34	0.7%
Refrigeration	0.23	0.23	0.23	0.24	0.25	0.27	0.28	0.8%
Office Equipment (PC)	0.17	0.21	0.25	0.28	0.30	0.33	0.35	2.1%
Office Equipment (non-PC)	0.39	0.42	0.55	0.68	0.79	0.87	0.92	3.3%
Other Uses[2]	1.34	1.39	1.55	1.77	2.01	2.26	2.54	2.5%
Delivered Energy	**4.35**	**4.43**	**4.73**	**5.19**	**5.67**	**6.15**	**6.62**	**1.7%**
Natural Gas								
Space Heating[1]	1.30	1.18	1.29	1.37	1.40	1.41	1.42	0.8%
Space Cooling[1]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.2%
Water Heating[1]	0.56	0.55	0.54	0.60	0.65	0.70	0.73	1.2%
Cooking	0.23	0.23	0.24	0.27	0.29	0.31	0.33	1.5%
Other Uses[3]	0.97	0.94	0.95	1.03	1.10	1.19	1.29	1.3%
Delivered Energy	**3.09**	**2.92**	**3.04**	**3.29**	**3.47**	**3.63**	**3.78**	**1.1%**
Distillate Fuel Oil								
Space Heating[1]	0.15	0.13	0.13	0.14	0.15	0.15	0.15	0.8%
Water Heating[1]	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.3%
Other Uses[4]	0.25	0.25	0.20	0.22	0.22	0.21	0.21	-0.6%
Delivered Energy	**0.45**	**0.42**	**0.38**	**0.41**	**0.41**	**0.42**	**0.41**	**-0.0%**
Marketed Renewables (biomass)	0.13	0.13	0.13	0.13	0.13	0.13	0.13	--
Other Fuels[5]	0.36	0.34	0.33	0.34	0.35	0.35	0.35	0.1%
Delivered Energy Consumption by End Use								
Space Heating[1]	1.59	1.44	1.56	1.65	1.69	1.71	1.71	0.7%
Space Cooling[1]	0.55	0.53	0.52	0.54	0.57	0.60	0.63	0.8%
Water Heating[1]	0.77	0.75	0.74	0.81	0.86	0.91	0.94	0.9%
Ventilation	0.19	0.19	0.19	0.20	0.21	0.22	0.23	0.9%
Cooking	0.27	0.27	0.28	0.31	0.33	0.35	0.36	1.2%
Lighting	1.16	1.15	1.12	1.17	1.22	1.28	1.34	0.7%
Refrigeration	0.23	0.23	0.23	0.24	0.25	0.27	0.28	0.8%
Office Equipment (PC)	0.17	0.21	0.25	0.28	0.30	0.33	0.35	2.1%
Office Equipment (non-PC)	0.39	0.42	0.55	0.68	0.79	0.87	0.92	3.3%
Other Uses[6]	3.05	3.05	3.17	3.49	3.81	4.15	4.53	1.7%
Delivered Energy	**8.38**	**8.25**	**8.62**	**9.37**	**10.03**	**10.67**	**11.30**	**1.3%**

Table A5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Electricity Related Losses	9.50	9.66	10.12	10.98	11.96	12.87	13.68	1.5%
Total Energy Consumption by End Use								
Space Heating[1]	1.90	1.73	1.86	1.95	1.99	2.02	2.02	0.7%
Space Cooling[1]	1.69	1.63	1.58	1.65	1.72	1.81	1.90	0.6%
Water Heating[1]	1.12	1.10	1.06	1.14	1.20	1.25	1.28	0.6%
Ventilation	0.60	0.60	0.60	0.62	0.65	0.68	0.71	0.7%
Cooking	0.36	0.35	0.36	0.39	0.41	0.42	0.43	0.9%
Lighting	3.69	3.66	3.52	3.63	3.79	3.96	4.12	0.5%
Refrigeration	0.73	0.73	0.73	0.75	0.79	0.82	0.86	0.6%
Office Equipment (PC)	0.56	0.68	0.80	0.86	0.93	1.02	1.08	1.9%
Office Equipment (non-PC)	1.24	1.34	1.73	2.11	2.46	2.68	2.81	3.1%
Other Uses[5]	5.97	6.08	6.49	7.23	8.05	8.89	9.77	2.0%
Total	17.87	17.91	18.74	20.34	21.98	23.54	24.98	1.4%
Nonmarketed Renewable Fuels[7]								
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.7%
Total	0.03	0.03	0.03	0.03	0.03	0.03	0.04	1.6%

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[7]Represents primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A6. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Key Indicators								
Value of Shipments (billion 2000 dollars)								
Manufacturing	4208	4290	4577	5076	5493	5883	6283	1.6%
Nonmanufacturing	1525	1531	1419	1583	1619	1663	1715	0.5%
Total	**5732**	**5821**	**5997**	**6659**	**7113**	**7546**	**7997**	**1.3%**
Energy Prices (2006 dollars per million Btu)								
Liquefied Petroleum Gases	17.54	19.71	17.74	16.65	16.79	17.10	17.79	-0.4%
Motor Gasoline	15.48	15.48	21.18	18.72	19.63	19.62	20.32	1.1%
Distillate Fuel Oil	14.50	15.33	15.72	13.95	14.62	15.10	16.26	0.2%
Residual Fuel Oil	10.43	9.06	10.86	8.24	8.29	9.00	9.62	0.2%
Petrochemical Feedstocks	9.01	9.01	9.22	8.32	8.25	8.53	8.94	-0.0%
Asphalt and Road Oil	5.49	4.63	9.66	7.28	5.74	5.93	6.35	1.3%
Natural Gas Heat and Power	7.43	6.69	6.38	5.26	5.35	5.71	6.45	-0.2%
Natural Gas Feedstocks	9.07	8.37	7.95	6.90	6.96	7.31	8.04	-0.2%
Metallurgical Coal	3.29	3.54	4.07	3.53	3.42	3.51	3.60	0.1%
Other Industrial Coal	2.22	2.34	2.42	2.31	2.28	2.30	2.33	-0.0%
Coal for Liquids	--	--	--	0.96	1.09	1.17	1.30	--
Electricity	17.25	17.97	19.21	17.22	17.27	17.30	17.63	-0.1%
Energy Consumption (quadrillion Btu)[1]								
Industrial Consumption Excluding Refining								
Liquefied Petroleum Gases Heat and Power	0.17	0.16	0.17	0.17	0.16	0.16	0.16	-0.1%
Liquefied Petroleum Gases Feedstocks	1.89	1.91	1.92	1.77	1.64	1.59	1.55	-0.9%
Motor Gasoline	0.37	0.38	0.38	0.37	0.37	0.38	0.38	0.1%
Distillate Fuel Oil	1.26	1.28	1.29	1.25	1.23	1.22	1.23	-0.2%
Residual Fuel Oil	0.27	0.27	0.28	0.23	0.22	0.21	0.21	-1.0%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Petroleum Coke	0.33	0.36	0.34	0.32	0.31	0.31	0.30	-0.8%
Asphalt and Road Oil	1.32	1.26	1.22	1.11	1.08	1.10	1.13	-0.5%
Miscellaneous Petroleum[2]	0.52	0.56	0.39	0.36	0.33	0.30	0.29	-2.7%
Petroleum Subtotal	7.53	7.60	7.34	7.04	6.73	6.59	6.55	-0.6%
Natural Gas Heat and Power	5.14	5.01	5.12	5.24	5.22	5.25	5.22	0.2%
Natural Gas Feedstocks	0.59	0.57	0.54	0.50	0.46	0.43	0.39	-1.5%
Lease and Plant Fuel[3]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Natural Gas Subtotal	6.88	6.74	6.86	6.97	6.93	6.95	6.88	0.1%
Metallurgical Coal and Coke[4]	0.66	0.66	0.63	0.57	0.57	0.56	0.52	-1.0%
Other Industrial Coal	1.22	1.20	1.25	1.16	1.14	1.13	1.12	-0.3%
Coal Subtotal	1.88	1.86	1.87	1.73	1.71	1.69	1.64	-0.5%
Renewables[5]	1.64	1.69	1.66	1.75	1.83	1.93	2.02	0.7%
Purchased Electricity	3.34	3.27	3.35	3.44	3.42	3.39	3.35	0.1%
Delivered Energy	**21.28**	**21.17**	**21.09**	**20.92**	**20.62**	**20.55**	**20.44**	**-0.1%**
Electricity Related Losses	7.30	7.13	7.17	7.26	7.22	7.09	6.92	-0.1%
Total	**28.58**	**28.29**	**28.27**	**28.18**	**27.84**	**27.64**	**27.35**	**-0.1%**
Refining Consumption								
Liquefied Petroleum Gases Heat and Power	0.02	0.01	0.03	0.03	0.03	0.00	0.00	-3.4%
Distillate Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Residual Fuel Oil	0.01	0.01	0.00	0.03	0.01	0.01	0.01	0.1%
Petroleum Coke	0.56	0.57	0.57	0.63	0.65	0.68	0.70	0.9%
Still Gas	1.64	1.69	1.72	1.87	1.85	1.87	1.98	0.7%
Miscellaneous Petroleum[2]	0.03	0.04	0.00	0.00	0.00	0.00	0.00	-10.1%
Petroleum Subtotal	2.26	2.32	2.33	2.56	2.55	2.56	2.70	0.6%
Natural Gas Heat and Power	1.05	1.10	1.51	1.46	1.47	1.49	1.47	1.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Natural Gas Subtotal	1.05	1.10	1.51	1.46	1.47	1.49	1.47	1.2%
Other Industrial Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	--
Coal Subtotal	0.06	0.06	0.06	0.19	0.40	0.45	0.61	10.0%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Purchased Electricity	0.13	0.15	0.15	0.17	0.17	0.17	0.17	0.7%
Delivered Energy	**3.75**	**3.94**	**4.72**	**5.38**	**6.07**	**6.95**	**7.27**	**2.6%**
Electricity Related Losses	0.29	0.32	0.33	0.37	0.36	0.35	0.36	0.5%
Total	**4.04**	**4.26**	**5.05**	**5.75**	**6.43**	**7.29**	**7.63**	**2.5%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Total Industrial Sector Consumption								
Liquefied Petroleum Gases Heat and Power	0.18	0.17	0.20	0.20	0.19	0.16	0.16	-0.3%
Liquefied Petroleum Gases Feedstocks	1.89	1.91	1.92	1.77	1.64	1.59	1.55	-0.9%
Motor Gasoline	0.37	0.38	0.38	0.37	0.37	0.38	0.38	0.1%
Distillate Fuel Oil	1.26	1.28	1.29	1.25	1.23	1.22	1.23	-0.2%
Residual Fuel Oil	0.28	0.28	0.28	0.25	0.23	0.23	0.23	-0.9%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Petroleum Coke	0.89	0.93	0.91	0.95	0.97	0.98	1.00	0.3%
Asphalt and Road Oil	1.32	1.26	1.22	1.11	1.08	1.10	1.13	-0.5%
Still Gas	1.64	1.69	1.72	1.87	1.85	1.87	1.98	0.7%
Miscellaneous Petroleum[2]	0.55	0.60	0.39	0.36	0.33	0.30	0.29	-3.0%
Petroleum Subtotal	9.79	9.92	9.67	9.60	9.27	9.15	9.25	-0.3%
Natural Gas Heat and Power	6.20	6.11	6.62	6.70	6.68	6.74	6.69	0.4%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Natural Gas Feedstocks	0.59	0.57	0.54	0.50	0.46	0.43	0.39	-1.5%
Lease and Plant Fuel[3]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Natural Gas Subtotal	7.93	7.85	8.37	8.43	8.39	8.44	8.35	0.3%
Metallurgical Coal and Coke[4]	0.66	0.66	0.63	0.57	0.57	0.56	0.52	-1.0%
Other Industrial Coal	1.28	1.26	1.31	1.22	1.20	1.19	1.18	-0.3%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	--
Coal Subtotal	1.95	1.92	1.93	1.92	2.11	2.14	2.26	0.7%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Renewables[5]	1.64	1.69	1.66	1.75	1.83	1.93	2.02	0.7%
Purchased Electricity	3.48	3.42	3.50	3.61	3.59	3.55	3.52	0.1%
Delivered Energy	**25.03**	**25.10**	**25.82**	**26.31**	**26.70**	**27.50**	**27.70**	**0.4%**
Electricity Related Losses	7.59	7.45	7.50	7.63	7.57	7.43	7.28	-0.1%
Total	**32.62**	**32.55**	**33.32**	**33.93**	**34.27**	**34.93**	**34.98**	**0.3%**
Energy Consumption per dollar of Shipment (thousand Btu per 2000 dollars)								
Liquefied Petroleum Gases Heat and Power	0.03	0.03	0.03	0.03	0.03	0.02	0.02	-1.6%
Liquefied Petroleum Gases Feedstocks	0.33	0.33	0.32	0.27	0.23	0.21	0.19	-2.2%
Motor Gasoline	0.07	0.06	0.06	0.06	0.05	0.05	0.05	-1.2%
Distillate Fuel Oil	0.22	0.22	0.22	0.19	0.17	0.16	0.15	-1.5%
Residual Fuel Oil	0.05	0.05	0.05	0.04	0.03	0.03	0.03	-2.3%
Petrochemical Feedstocks	0.25	0.24	0.23	0.22	0.19	0.18	0.16	-1.7%
Petroleum Coke	0.16	0.16	0.15	0.14	0.14	0.13	0.13	-1.0%
Asphalt and Road Oil	0.23	0.22	0.20	0.17	0.15	0.15	0.14	-1.8%
Still Gas	0.29	0.29	0.29	0.28	0.26	0.25	0.25	-0.7%
Miscellaneous Petroleum[2]	0.10	0.10	0.06	0.05	0.05	0.04	0.04	-4.2%
Petroleum Subtotal	1.71	1.70	1.61	1.44	1.30	1.21	1.16	-1.6%
Natural Gas Heat and Power	1.08	1.05	1.10	1.01	0.94	0.89	0.84	-0.9%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Natural Gas Feedstocks	0.10	0.10	0.09	0.08	0.06	0.06	0.05	-2.8%
Lease and Plant Fuel[3]	0.20	0.20	0.20	0.18	0.18	0.17	0.16	-1.0%
Natural Gas Subtotal	1.38	1.35	1.40	1.27	1.18	1.12	1.04	-1.1%
Metallurgical Coal and Coke[4]	0.12	0.11	0.10	0.09	0.08	0.07	0.07	-2.3%
Other Industrial Coal	0.22	0.22	0.22	0.18	0.17	0.16	0.15	-1.6%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.02	0.05	0.05	0.07	--
Coal Subtotal	0.34	0.33	0.32	0.29	0.30	0.28	0.28	-0.7%
Biofuels Heat and Coproducts	0.04	0.05	0.11	0.15	0.21	0.30	0.29	7.4%
Renewables[5]	0.29	0.29	0.28	0.26	0.26	0.26	0.25	-0.6%
Purchased Electricity	0.61	0.59	0.58	0.54	0.50	0.47	0.44	-1.2%
Delivered Energy	**4.37**	**4.31**	**4.31**	**3.95**	**3.75**	**3.64**	**3.46**	**-0.9%**
Electricity Related Losses	1.32	1.28	1.25	1.15	1.06	0.99	0.91	-1.4%
Total	**5.69**	**5.59**	**5.56**	**5.10**	**4.82**	**4.63**	**4.37**	**-1.0%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Industrial Combined Heat and Power								
Capacity (gigawatts)	26.87	25.69	28.11	31.79	36.84	42.15	44.85	2.3%
Generation (billion kilowatthours)	139.95	139.50	155.59	182.91	220.78	261.90	281.41	3.0%

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
-- = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 prices for motor gasoline and distillate fuel oil are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2005 and 2006 petrochemical feedstock and asphalt and road oil prices are based on: *State Energy Data Report 2005*, DOE/EIA-0214(2005) (Washington, DC, June 2007). 2005 and 2006 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007) and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. 2005 and 2006 electricity prices: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 natural gas prices are based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 refining consumption based on: *Petroleum Supply Annual 2005*, DOE/EIA-0340(2005)/1 (Washington, DC, October 2006). 2006 refining consumption based on: *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). Other 2005 and 2006 consumption values are based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 industrial shipments: Global Insight, Global Insight Industry model, July 2007. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Key Indicators								
Travel Indicators								
(billion vehicle miles traveled)								
Light-Duty Vehicles less than 8,500 pounds	2687	2693	2777	3058	3375	3717	4069	1.7%
Commercial Light Trucks[1]	69	70	73	81	87	94	101	1.5%
Freight Trucks greater than 10,000 pounds	228	235	250	279	304	328	351	1.7%
(billion seat miles available)								
Air	1029	994	1130	1318	1457	1576	1665	2.2%
(billion ton miles traveled)								
Rail	1588	1656	1702	1827	1932	2043	2147	1.1%
Domestic Shipping	610	619	643	677	701	713	721	0.6%
Energy Efficiency Indicators								
(miles per gallon)								
Tested New Light-Duty Vehicle[2]	25.5	26.5	27.2	30.8	35.8	36.4	36.6	1.4%
New Car[2]	30.2	31.1	31.5	34.9	42.0	42.1	42.1	1.3%
New Light Truck[2]	22.4	23.2	23.7	27.7	31.4	32.2	32.4	1.4%
On-Road New Light-Duty Vehicle[3]	20.6	21.5	22.1	25.2	29.4	30.1	30.5	1.5%
New Car[3]	24.5	25.3	25.7	28.7	34.7	35.1	35.3	1.4%
New Light Truck[3]	18.0	18.7	19.2	22.5	25.7	26.5	26.9	1.5%
Light-Duty Stock[4]	19.9	20.3	20.3	21.5	23.7	26.1	27.9	1.3%
New Commercial Light Truck[1]	15.0	15.6	15.7	18.1	19.8	20.2	20.2	1.1%
Stock Commercial Light Truck[1]	14.1	14.3	14.9	15.9	17.4	18.9	19.8	1.4%
Freight Truck	6.0	6.0	6.0	6.2	6.5	6.7	6.8	0.5%
(seat miles per gallon)								
Aircraft	60.9	62.2	63.5	65.3	67.2	68.7	70.0	0.5%
(ton miles per thousand Btu)								
Rail	2.9	2.9	2.9	2.9	3.0	3.0	3.0	0.1%
Domestic Shipping	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.1%
Energy Use by Mode								
(quadrillion Btu)								
Light-Duty Vehicles	16.23	16.41	16.52	17.01	17.10	17.11	17.52	0.3%
Commercial Light Trucks[1]	0.61	0.62	0.62	0.64	0.63	0.63	0.64	0.2%
Bus Transportation	0.26	0.26	0.26	0.27	0.27	0.28	0.29	0.3%
Freight Trucks	4.74	4.89	5.18	5.60	5.85	6.13	6.44	1.2%
Rail, Passenger	0.04	0.04	0.05	0.05	0.05	0.05	0.06	1.1%
Rail, Freight	0.55	0.57	0.58	0.62	0.65	0.69	0.72	1.0%
Shipping, Domestic	0.31	0.32	0.33	0.34	0.35	0.36	0.36	0.5%
Shipping, International	0.77	0.78	0.79	0.78	0.79	0.80	0.80	0.1%
Recreational Boats	0.24	0.24	0.25	0.26	0.28	0.29	0.30	0.9%
Air	2.72	2.65	2.90	3.29	3.61	3.92	4.22	2.0%
Military Use	0.68	0.69	0.73	0.71	0.73	0.75	0.76	0.4%
Lubricants	0.15	0.15	0.14	0.14	0.14	0.15	0.15	0.1%
Pipeline Fuel	0.60	0.59	0.64	0.66	0.69	0.72	0.72	0.8%
Total	**27.90**	**28.20**	**28.98**	**30.37**	**31.15**	**31.86**	**32.98**	**0.7%**

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Energy Use by Mode (million barrels per day oil equivalent)								
Light-Duty Vehicles	8.51	8.60	8.94	9.26	9.48	9.56	9.74	0.5%
Commercial Light Trucks[1]	0.32	0.32	0.33	0.35	0.34	0.34	0.35	0.3%
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.14	0.4%
Freight Trucks	2.26	2.33	2.48	2.69	2.80	2.94	3.09	1.2%
Rail, Passenger	0.02	0.02	0.02	0.02	0.02	0.03	0.03	1.1%
Rail, Freight	0.26	0.27	0.28	0.30	0.31	0.33	0.34	1.0%
Shipping, Domestic	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.5%
Shipping, International	0.34	0.34	0.35	0.34	0.35	0.35	0.35	0.1%
Recreational Boats	0.13	0.13	0.14	0.14	0.15	0.16	0.16	1.1%
Air	1.32	1.28	1.40	1.59	1.75	1.89	2.04	2.0%
Military Use	0.33	0.33	0.35	0.34	0.35	0.36	0.37	0.4%
Lubricants	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.1%
Pipeline Fuel	0.30	0.30	0.32	0.33	0.35	0.36	0.36	0.8%
Total	**14.11**	**14.27**	**14.96**	**15.72**	**16.27**	**16.69**	**17.20**	**0.8%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006: Energy Information Administration (EIA), *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006); EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007); Federal Highway Administration, *Highway Statistics 2005* (Washington, DC, December 2006); Oak Ridge National Laboratory, Transportation Energy Data Book: Edition 26 and Annual (Oak Ridge, TN, 2007); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2004); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, *State Energy Data Report 2005*, DOE/EIA-0214(2005) (Washington, DC, June 2007); EIA, *Alternatives to Traditional Transportation Fuels 2005 (Part II-User and Fuel Data)*, November 2007; U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2006/2005* (Washington, DC, 2006); EIA, *Fuel Oil and Kerosene Sales 2004*, DOE/EIA-0535(2004) (Washington, DC, November 2005); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Generation by Fuel Type								
Electric Power Sector[1]								
Power Only[2]								
Coal	1956	1930	2002	2122	2287	2502	2756	1.5%
Petroleum	111	55	49	50	52	54	56	0.1%
Natural Gas[3]	554	608	695	682	614	543	503	-0.8%
Nuclear Power	782	787	797	807	868	911	917	0.6%
Pumped Storage/Other[4]	1	0	1	1	1	1	1	5.4%
Renewable Sources[5]	319	347	421	465	518	540	553	2.0%
Distributed Generation (Natural Gas)	0	0	0	1	1	2	4	--
Total	**3722**	**3727**	**3965**	**4128**	**4340**	**4552**	**4790**	**1.1%**
Combined Heat and Power[6]								
Coal	37	36	32	32	32	32	31	-0.6%
Petroleum	6	4	1	1	1	1	1	-6.7%
Natural Gas	130	124	124	123	108	99	96	-1.1%
Renewable Sources	4	4	4	4	5	5	5	0.5%
Total	**180**	**173**	**160**	**160**	**145**	**136**	**133**	**-1.1%**
Total Net Generation	**3902**	**3900**	**4125**	**4288**	**4485**	**4688**	**4923**	**1.0%**
Less Direct Use	33	33	34	34	34	34	34	0.1%
Net Available to the Grid	**3869**	**3866**	**4091**	**4254**	**4451**	**4654**	**4889**	**1.0%**
End-Use Generation[7]								
Coal	22	22	21	28	39	41	51	3.6%
Petroleum	6	4	6	6	7	9	9	3.6%
Natural Gas	73	74	88	99	111	124	138	2.6%
Other Gaseous Fuels[8]	5	5	4	4	4	4	4	-0.7%
Renewable Sources[9]	34	34	37	48	65	94	98	4.5%
Other[10]	14	13	12	12	12	12	12	-0.4%
Total	**152**	**152**	**169**	**197**	**238**	**285**	**313**	**3.1%**
Less Direct Use	123	121	134	155	182	211	234	2.8%
Total Sales to the Grid	**30**	**31**	**34**	**42**	**56**	**74**	**79**	**4.0%**
Total Electricity Generation	**4054**	**4051**	**4294**	**4485**	**4723**	**4973**	**5235**	**1.1%**
Total Net Generation to the Grid	**3899**	**3897**	**4126**	**4296**	**4507**	**4728**	**4968**	**1.0%**
Net Imports	**25**	**18**	**15**	**11**	**13**	**16**	**23**	**1.0%**
Electricity Sales by Sector								
Residential	1359	1351	1450	1472	1540	1620	1722	1.0%
Commercial	1275	1300	1386	1522	1661	1802	1941	1.7%
Industrial	1019	1002	1027	1058	1052	1041	1033	0.1%
Transportation	6	6	7	7	8	8	9	1.3%
Total	**3660**	**3659**	**3869**	**4059**	**4261**	**4472**	**4705**	**1.1%**
Direct Use	156	154	168	189	216	245	267	2.3%
Total Electricity Use	**3815**	**3814**	**4037**	**4248**	**4477**	**4717**	**4972**	**1.1%**
End-Use Prices (2006 cents per kilowatthour)								
Residential	9.7	10.4	10.7	10.2	10.3	10.3	10.5	0.0%
Commercial	8.9	9.5	9.5	8.7	8.7	8.8	8.9	-0.2%
Industrial	5.9	6.1	6.6	5.9	5.9	5.9	6.0	-0.1%
Transportation	10.5	10.1	10.6	9.9	9.9	9.9	10.1	-0.0%
All Sectors Average	**8.4**	**8.9**	**9.2**	**8.5**	**8.6**	**8.7**	**8.8**	**-0.0%**
Prices by Service Category (2006 cents per kilowatthour)								
Generation	5.4	5.9	6.2	5.5	5.6	5.7	5.9	-0.1%
Transmission	0.6	0.6	0.7	0.8	0.8	0.8	0.8	1.1%
Distribution	2.3	2.3	2.3	2.3	2.3	2.2	2.2	-0.2%

Table A8. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Electric Power Sector Emissions[1]								
Sulfur Dioxide (million tons)	10.22	9.39	6.43	4.67	3.77	3.66	3.71	-3.8%
Nitrogen Oxide (million tons)	3.64	3.41	2.33	2.11	2.11	2.14	2.16	-1.9%
Mercury (tons)	51.72	50.37	37.24	24.75	19.23	16.88	14.95	-4.9%

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The Energy Information Administration estimates approximately 7 billion kilowatthours of electricity was generated from this material in 2005. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), and supporting databases. 2005 and 2006 prices: EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Electric Power Sector[2]								
Power Only[3]								
Coal	305.1	305.2	311.4	319.3	338.5	367.6	401.5	1.1%
Oil and Natural Gas Steam[4]	120.8	119.3	118.0	93.2	93.0	92.6	92.6	-1.1%
Combined Cycle	137.4	144.7	158.2	159.9	164.2	173.3	177.5	0.9%
Combustion Turbine/Diesel	127.4	128.1	134.5	127.1	129.2	140.9	161.8	1.0%
Nuclear Power[5]	100.2	100.2	100.9	102.1	110.9	115.7	114.9	0.6%
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Renewable Sources[6]	92.8	95.7	110.9	116.6	122.9	127.5	131.8	1.3%
Distributed Generation[7]	0.0	0.0	0.3	0.9	2.7	5.9	9.8	--
Total	**905.2**	**914.7**	**955.7**	**940.6**	**982.8**	**1045.0**	**1111.4**	**0.8%**
Combined Heat and Power[8]								
Coal	4.6	4.6	4.6	4.6	4.6	4.6	4.6	0.0%
Oil and Natural Gas Steam[4]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0%
Combined Cycle	31.9	31.8	31.8	32.5	32.5	32.5	32.5	0.1%
Combustion Turbine/Diesel	2.9	2.9	2.9	2.9	2.9	2.9	2.9	-0.0%
Renewable Sources[6]	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.2%
Total	**40.4**	**40.3**	**40.3**	**41.0**	**41.0**	**41.0**	**41.0**	**0.1%**
Cumulative Planned Additions[9]								
Coal	0.0	0.0	7.7	10.7	10.7	10.7	10.7	--
Oil and Natural Gas Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Combined Cycle	0.0	0.0	13.5	15.5	15.5	15.5	15.5	--
Combustion Turbine/Diesel	0.0	0.0	3.9	3.9	3.9	3.9	3.9	--
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Renewable Sources[6]	0.0	0.0	9.5	9.5	9.6	9.8	9.9	--
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Total	**0.0**	**0.0**	**34.5**	**39.6**	**39.7**	**39.9**	**40.0**	**--**
Cumulative Unplanned Additions[9]								
Coal	0.0	0.0	0.0	6.8	26.3	55.6	89.5	--
Oil and Natural Gas Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Combined Cycle	0.0	0.0	0.0	0.3	4.6	13.7	17.9	--
Combustion Turbine/Diesel	0.0	0.0	3.3	4.6	6.7	18.4	39.5	--
Nuclear Power	0.0	0.0	0.0	0.0	8.0	12.8	16.6	--
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Renewable Sources[6]	0.0	0.0	5.8	11.5	17.6	22.2	26.3	--
Distributed Generation[7]	0.0	0.0	0.3	0.9	2.7	5.9	9.8	--
Total	**0.0**	**0.0**	**9.5**	**24.1**	**65.9**	**128.5**	**199.6**	**--**
Cumulative Electric Power Sector Additions	**0.0**	**0.0**	**44.0**	**63.7**	**105.7**	**168.4**	**239.6**	**--**
Cumulative Retirements[10]								
Coal	0.0	0.0	1.5	3.4	3.7	3.9	3.9	--
Oil and Natural Gas Steam[4]	0.0	0.0	1.4	26.1	26.4	26.7	26.8	--
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Combustion Turbine/Diesel	0.0	0.0	0.7	9.4	9.4	9.4	9.7	--
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	4.5	--
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Renewable Sources[6]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--
Total	**0.0**	**0.0**	**3.6**	**38.9**	**39.5**	**40.0**	**44.8**	**--**
Total Electric Power Sector Capacity	**945.6**	**955.0**	**996.0**	**981.6**	**1023.8**	**1086.0**	**1152.4**	**0.8%**

Table A9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
End-Use Generators[11]								
Coal	4.1	4.0	4.0	4.9	6.3	6.6	8.0	2.9%
Petroleum	1.2	1.2	1.7	1.7	1.9	2.1	2.1	2.4%
Natural Gas	14.7	14.1	15.8	17.2	18.8	20.6	22.4	2.0%
Other Gaseous Fuels	2.2	1.8	1.7	1.7	1.7	1.7	1.7	-0.1%
Renewable Sources[6]	6.0	6.0	6.7	8.2	10.8	15.2	16.7	4.4%
Other	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.0%
Total	**29.0**	**27.9**	**30.7**	**34.6**	**40.4**	**47.0**	**51.8**	**2.6%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**2.9**	**6.8**	**12.5**	**19.1**	**23.9**	**--**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 2.7 gigawatts of uprates through 2030.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[9]Cumulative additions after December 31, 2006.
[10]Cumulative retirements after December 31, 2006.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
-- = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Interregional Electricity Trade								
Gross Domestic Sales								
Firm Power	127.0	119.4	105.5	82.4	50.6	37.9	37.9	-4.7%
Economy	177.3	169.7	207.2	260.7	220.3	229.5	222.6	1.1%
Total	**304.3**	**289.1**	**312.7**	**343.1**	**270.9**	**267.4**	**260.4**	**-0.4%**
Gross Domestic Sales (million 2006 dollars)								
Firm Power	7077.5	6656.0	5877.2	4592.5	2820.0	2111.0	2111.0	-4.7%
Economy	12274.8	9907.5	12125.3	12861.2	10709.6	10964.4	11182.2	0.5%
Total	**19352.3**	**16563.4**	**18002.5**	**17453.6**	**13529.6**	**13075.4**	**13293.2**	**-0.9%**
International Electricity Trade								
Imports from Canada and Mexico								
Firm Power	13.1	13.7	2.5	1.9	0.8	0.4	0.4	-13.8%
Economy	31.4	28.8	28.9	24.7	26.6	27.5	34.3	0.7%
Total	**44.5**	**42.4**	**31.4**	**26.6**	**27.4**	**27.9**	**34.7**	**-0.8%**
Exports to Canada and Mexico								
Firm Power	2.9	3.2	1.0	0.7	0.2	0.0	0.0	--
Economy	16.9	21.4	15.5	15.0	14.0	12.1	12.1	-2.3%
Total	**19.8**	**24.6**	**16.5**	**15.6**	**14.2**	**12.1**	**12.1**	**-2.9%**

-- = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2005 and 2006 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2004. 2005 and 2006 Mexican electricity trade data: Energy Information Administration (EIA), *Electric Power Annual 2006* DOE/EIA-0348(2006) (Washington, DC, November 2007). 2005 Canadian international electricity trade data: National Energy Board, *Annual Report 2005.* 2006 Canadian electricity trade data: National Energy Board, *Annual Report 2006.* **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A11. Liquid Fuels Supply and Disposition
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Crude Oil								
Domestic Crude Production[1]	5.19	5.10	5.93	6.16	6.23	6.04	5.59	0.4%
Alaska	0.86	0.74	0.69	0.57	0.70	0.53	0.30	-3.7%
Lower 48 States	4.33	4.36	5.24	5.59	5.53	5.51	5.30	0.8%
Net Imports	10.09	10.09	9.60	9.89	9.75	10.11	11.03	0.4%
Gross Imports	10.12	10.12	9.63	9.92	9.79	10.14	11.06	0.4%
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.4%
Other Crude Supply[2]	-0.05	0.05	0.00	0.00	0.00	0.00	0.00	--
Total Crude Supply	**15.23**	**15.24**	**15.53**	**16.04**	**15.98**	**16.15**	**16.63**	**0.4%**
Other Supply								
Natural Gas Plant Liquids	1.72	1.74	1.68	1.70	1.72	1.61	1.57	-0.4%
Net Product Imports	2.47	2.31	1.72	1.47	1.37	1.27	1.26	-2.5%
Gross Refined Product Imports[3]	2.45	2.17	1.61	1.34	1.41	1.50	1.56	-1.4%
Unfinished Oil Imports	0.58	0.69	0.67	0.67	0.64	0.62	0.70	0.1%
Blending Component Imports	0.54	0.68	0.74	0.79	0.67	0.59	0.52	-1.1%
Exports	1.07	1.22	1.30	1.33	1.36	1.45	1.52	0.9%
Refinery Processing Gain[4]	0.99	0.99	1.05	1.06	1.00	0.97	0.99	0.0%
Other Inputs	0.41	0.45	1.04	1.46	1.97	2.34	2.41	7.2%
Ethanol	0.26	0.36	0.81	1.04	1.41	1.59	1.56	6.2%
Domestic Production	0.25	0.32	0.74	0.93	1.17	1.45	1.44	6.5%
Net Imports	0.01	0.05	0.07	0.11	0.24	0.15	0.12	4.0%
Biodiesel	0.01	0.02	0.04	0.08	0.07	0.07	0.08	6.9%
Domestic Production	0.01	0.02	0.04	0.08	0.07	0.07	0.08	6.9%
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Liquids from Coal	0.00	0.00	0.00	0.06	0.15	0.17	0.24	--
Liquids from Biomass	0.00	0.00	0.00	0.07	0.14	0.28	0.29	--
Other[5]	0.14	0.07	0.18	0.21	0.21	0.22	0.24	5.0%
Total Primary Supply[6]	**20.82**	**20.74**	**21.02**	**21.74**	**22.04**	**22.34**	**22.86**	**0.4%**
Liquid Fuels Consumption								
by Fuel								
Liquefied Petroleum Gases	2.03	2.05	2.05	1.96	1.86	1.81	1.80	-0.5%
E85[7]	0.00	0.00	0.00	0.12	0.67	0.97	0.92	33.5%
Motor Gasoline[8]	9.16	9.25	9.59	9.73	9.24	8.84	8.91	-0.2%
Jet Fuel[9]	1.68	1.63	1.66	1.85	2.01	2.16	2.31	1.5%
Distillate Fuel Oil[10]	4.12	4.17	4.40	4.68	4.91	5.19	5.53	1.2%
Diesel	3.04	3.21	3.72	4.00	4.23	4.52	4.87	1.8%
Residual Fuel Oil	0.92	0.69	0.70	0.69	0.69	0.69	0.70	0.0%
Other[11]	2.89	2.86	2.58	2.65	2.58	2.57	2.62	-0.4%
by Sector								
Residential and Commercial	1.19	1.07	1.08	1.11	1.13	1.12	1.12	0.2%
Industrial[12]	5.09	5.15	5.06	4.98	4.79	4.70	4.73	-0.4%
Transportation	13.91	14.05	14.60	15.33	15.79	16.15	16.66	0.7%
Electric Power[13]	0.55	0.29	0.25	0.25	0.26	0.27	0.28	-0.1%
Total	**20.80**	**20.65**	**20.99**	**21.68**	**21.96**	**22.25**	**22.80**	**0.4%**
Discrepancy[14]	**0.02**	**0.09**	**0.03**	**0.06**	**0.08**	**0.09**	**0.06**	--

Table A11. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Domestic Refinery Distillation Capacity[15]	17.1	17.3	18.3	18.3	18.3	18.3	18.4	0.3%
Capacity Utilization Rate (percent)[16]	91.0	90.0	86.8	89.6	89.3	90.1	92.0	0.1%
Net Import Share of Product Supplied (percent)	60.4	60.0	54.2	52.8	51.6	51.6	54.3	-0.4%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2006 dollars)	251.73	264.86	254.07	203.53	207.19	228.18	261.91	-0.0%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, and ethers.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[11]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, liquid hydrogen,and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.

Sources: 2005 and 2006 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2005 data: EIA, *Petroleum Supply Annual 2005*, DOE/EIA-0340(2005)/1 (Washington, DC, October 2006). Other 2006 data: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A12. Petroleum Product Prices
(2006 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Crude Oil Prices (2006 dollars per barrel)								
Imported Low Sulfur Light Crude Oil	58.28	66.02	74.03	59.85	59.70	64.49	70.45	0.3%
Imported Crude Oil[1]	50.40	59.05	65.18	52.03	51.55	55.68	58.66	-0.0%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	162.3	198.1	216.3	207.3	207.9	211.4	218.3	0.4%
Distillate Fuel Oil	235.6	248.8	238.6	197.9	198.0	209.9	225.7	-0.4%
Commercial								
Distillate Fuel Oil	191.2	201.8	210.2	177.5	182.5	191.3	206.7	0.1%
Residual Fuel Oil	167.8	128.8	150.7	119.0	118.9	129.1	138.0	0.3%
Residual Fuel Oil (2006 dollars per barrel)	70.46	54.09	63.27	49.97	49.95	54.21	57.97	0.3%
Industrial[2]								
Liquefied Petroleum Gases	151.1	169.2	152.3	142.9	144.1	146.8	152.7	-0.4%
Distillate Fuel Oil	200.8	212.1	216.2	191.6	200.7	207.3	223.1	0.2%
Residual Fuel Oil	156.2	135.6	162.6	123.4	124.0	134.7	144.0	0.2%
Residual Fuel Oil (2006 dollars per barrel)	65.60	56.96	68.29	51.82	52.10	56.57	60.48	0.2%
Transportation								
Liquefied Petroleum Gases	176.6	186.4	223.4	214.0	214.0	216.9	223.4	0.8%
Ethanol (E85)[3]	226.6	235.4	223.7	167.0	172.2	175.5	186.1	-1.0%
Ethanol Wholesale Price	196.8	250.0	180.8	171.3	200.7	164.6	152.2	-2.0%
Motor Gasoline[4]	239.5	263.3	255.4	225.4	235.5	236.0	244.6	-0.3%
Jet Fuel[5]	179.6	200.2	212.8	177.6	179.2	191.0	207.5	0.1%
Diesel Fuel (distillate fuel oil)[6]	249.1	271.0	269.8	241.8	250.2	254.1	268.5	-0.0%
Residual Fuel Oil	129.9	118.1	157.7	128.2	130.1	142.1	155.5	1.2%
Residual Fuel Oil (2006 dollars per barrel)	54.56	49.62	66.22	53.84	54.64	59.70	65.32	1.2%
Electric Power[7]								
Distillate Fuel Oil	175.1	185.1	189.0	148.0	148.3	160.8	176.2	-0.2%
Residual Fuel Oil	110.8	122.3	141.5	110.9	112.3	123.4	135.3	0.4%
Residual Fuel Oil (2006 dollars per barrel)	46.52	51.37	59.43	46.56	47.18	51.85	56.84	0.4%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	153.0	174.6	165.4	157.2	159.5	163.3	170.1	-0.1%
Motor Gasoline[4]	238.4	261.6	255.4	225.4	235.5	236.0	244.6	-0.3%
Jet Fuel[5]	179.6	200.2	212.8	177.6	179.2	191.0	207.5	0.1%
Distillate Fuel Oil	236.3	255.9	253.9	227.4	236.1	241.9	257.1	0.0%
Residual Fuel Oil	126.4	122.9	154.3	122.6	124.1	135.6	147.7	0.8%
Residual Fuel Oil (2006 dollars per barrel)	53.07	51.63	64.80	51.50	52.12	56.94	62.04	0.8%
Average	**213.0**	**234.5**	**233.1**	**206.6**	**214.1**	**218.0**	**229.6**	**-0.1%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2005 and 2006 imported crude oil price: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2005 and 2006 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2005 and 2006 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2005 and 2006 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2005 and 2006 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A13. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Production								
Dry Gas Production[1]	18.07	18.51	19.29	19.52	19.67	19.60	19.43	0.2%
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
Net Imports	**3.61**	**3.46**	**3.85**	**4.03**	**3.55**	**3.28**	**3.18**	**-0.4%**
Pipeline[3]	3.05	2.94	2.64	1.91	1.18	0.68	0.33	-8.7%
Liquefied Natural Gas	0.57	0.52	1.20	2.12	2.37	2.60	2.84	7.3%
Total Supply	**21.75**	**22.03**	**23.20**	**23.61**	**23.28**	**22.94**	**22.68**	**0.1%**
Consumption by Sector								
Residential	4.83	4.37	4.81	5.01	5.15	5.19	5.17	0.7%
Commercial	3.00	2.83	2.96	3.20	3.37	3.53	3.67	1.1%
Industrial[4]	6.60	6.49	6.95	7.00	6.93	6.96	6.87	0.2%
Natural-Gas-to-Liquids Heat and Power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Natural Gas to Liquids Production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Electric Power[7]	5.87	6.24	6.70	6.56	5.92	5.30	4.99	-0.9%
Transportation[8]	0.01	0.02	0.03	0.06	0.07	0.08	0.09	6.2%
Pipeline Fuel	0.58	0.58	0.62	0.64	0.67	0.70	0.70	0.8%
Lease and Plant Fuel[9]	1.11	1.14	1.18	1.19	1.22	1.24	1.23	0.3%
Total	**22.01**	**21.66**	**23.25**	**23.66**	**23.33**	**22.99**	**22.72**	**0.2%**
Discrepancy[10]	**-0.26**	**0.37**	**-0.05**	**-0.05**	**-0.05**	**-0.04**	**-0.05**	**--**
Natural Gas Prices								
(2006 dollars per million Btu)								
Henry Hub Spot Price	8.93	6.73	6.90	5.87	5.95	6.39	7.22	0.3%
Average Lower 48 Wellhead Price[11]	7.62	6.24	6.16	5.21	5.29	5.69	6.45	0.1%
(2006 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	7.85	6.42	6.33	5.36	5.44	5.86	6.63	0.1%
Delivered Prices								
Residential	13.23	13.80	12.52	11.54	11.74	12.29	13.30	-0.2%
Commercial	11.86	11.85	10.91	9.97	10.20	10.78	11.78	-0.0%
Industrial[4]	8.62	7.89	7.43	6.33	6.40	6.76	7.50	-0.2%
Electric Power[7]	8.67	7.07	7.16	6.10	6.11	6.44	7.13	0.0%
Transportation[12]	14.97	14.71	14.01	12.71	12.52	12.65	13.22	-0.4%
Average[13]	**10.22**	**9.49**	**8.97**	**8.00**	**8.22**	**8.73**	**9.63**	**0.1%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas that is converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Compressed natural gas used as vehicle fuel.
[9]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. 2005 and 2006 values include net storage injections.
[11]Represents lower 48 onshore and offshore supplies.
[12]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[13]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
-- = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 supply values; lease, plant, and pipeline fuel consumption; and residential and commercial delivered prices: Energy Information Administration (EIA), *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2006 supply values; lease, plant, and pipeline fuel consumption; wellhead price; and residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). Other 2005 and 2006 consumption based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2005 and 2006 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2006 through April 2007, Table 4.11.A. 2005 and 2006 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and estimated state taxes, federal taxes, and dispensing costs or charges. 2006 transportation sector delivered prices are model results. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Crude Oil								
Lower 48 Average Wellhead Price[1] (2006 dollars per barrel)	52.37	60.18	78.45	57.71	52.54	55.77	60.59	0.0%
Production (million barrels per day)[2]								
United States Total	5.19	5.10	5.93	6.16	6.23	6.04	5.59	0.4%
Lower 48 Onshore	2.91	2.93	3.10	3.20	3.28	3.43	3.38	0.6%
Lower 48 Offshore	1.41	1.43	2.14	2.38	2.25	2.08	1.92	1.2%
Alaska	0.86	0.74	0.69	0.57	0.70	0.53	0.30	-3.7%
Lower 48 End of Year Reserves[2] (billion barrels)	18.85	19.02	19.89	20.93	20.78	20.72	19.89	0.2%
Natural Gas								
Prices (2006 dollars per million Btu)								
Henry Hub Spot Price	8.93	6.73	6.90	5.87	5.95	6.39	7.22	0.3%
Average Lower 48 Wellhead Price[1]	7.62	6.24	6.16	5.21	5.29	5.69	6.45	0.1%
Prices (2006 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[1]	7.85	6.42	6.33	5.36	5.44	5.86	6.63	0.1%
Dry Production (trillion cubic feet)[3]								
United States Total	18.07	18.51	19.29	19.52	19.67	19.60	19.44	0.2%
Lower 48 Onshore	14.24	15.04	15.26	14.81	14.16	13.74	13.95	-0.3%
Associated-Dissolved[4]	1.35	1.42	1.41	1.40	1.33	1.29	1.20	-0.7%
Non-Associated	12.90	13.62	13.85	13.41	12.83	12.45	12.76	-0.3%
Conventional	5.00	5.14	4.81	3.96	3.47	3.18	3.23	-1.9%
Unconventional	7.89	8.48	9.04	9.45	9.36	9.28	9.53	0.5%
Lower 48 Offshore	3.37	3.05	3.61	4.32	4.31	3.86	3.47	0.5%
Associated-Dissolved[4]	0.68	0.62	0.73	0.95	0.97	0.87	0.77	0.9%
Non-Associated	2.69	2.43	2.88	3.37	3.35	2.99	2.69	0.4%
Alaska	0.46	0.42	0.42	0.38	1.19	2.00	2.01	6.7%
Lower 48 End of Year Dry Reserves (trillion cubic feet)	196.22	202.99	220.62	227.01	219.31	207.16	200.42	-0.1%
Supplemental Gas Supplies (trillion cubic feet)[5]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
Total Lower 48 Wells Drilled (thousands)	41.54	49.72	62.33	42.40	37.19	34.02	35.78	-1.4%

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.

Sources: 2005 and 2006 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2005 and 2006 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2005 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2005) (Washington, DC, November 2006). 2005 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2005 natural gas lower 48 average wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2006 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). Other 2005 and 2006 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Production[1]								
Appalachia	397	392	381	340	327	324	328	-0.7%
Interior	149	151	166	193	199	219	241	2.0%
West	585	619	619	682	745	820	885	1.5%
East of the Mississippi	494	491	488	460	447	457	481	-0.1%
West of the Mississippi	638	672	678	755	823	906	974	1.6%
Total	**1131**	**1163**	**1166**	**1215**	**1270**	**1363**	**1455**	**0.9%**
Waste Coal Supplied[2]	**13**	**14**	**13**	**14**	**11**	**11**	**12**	**-0.4%**
Net Imports								
Imports[3]	29	34	37	42	80	93	112	5.1%
Exports	50	50	71	45	34	35	35	-1.5%
Total	**-21**	**-15**	**-34**	**-3**	**46**	**57**	**78**	--
Total Supply[4]	**1124**	**1161**	**1144**	**1225**	**1326**	**1431**	**1545**	**1.2%**
Consumption by Sector								
Residential and Commercial	4	4	4	4	4	4	4	-0.2%
Coke Plants	23	23	23	21	20	20	18	-0.9%
Other Industrial[5]	60	61	64	60	59	58	58	-0.2%
Coal-to-Liquids Heat and Power	0	0	0	9	23	25	35	--
Coal to Liquids Production	0	0	0	7	19	21	29	--
Electric Power[6]	1037	1026	1054	1125	1202	1303	1401	1.3%
Total	**1125**	**1114**	**1145**	**1225**	**1327**	**1431**	**1545**	**1.4%**
Discrepancy and Stock Change[7]	**-2**	**47**	**-0**	**-0**	**-0**	**-0**	**-0**	--
Average Minemouth Price[8]								
(2006 dollars per short ton)	24.08	24.63	26.16	23.38	22.51	22.75	23.32	-0.2%
(2006 dollars per million Btu)	1.18	1.21	1.28	1.17	1.14	1.16	1.19	-0.1%
Delivered Prices (2006 dollars per short ton)[9]								
Coke Plants	86.43	92.87	107.02	92.85	89.86	92.16	94.68	0.1%
Other Industrial[5]	49.13	51.67	51.64	49.16	48.82	49.21	49.91	-0.1%
Coal to Liquids	--	--	--	14.44	16.54	18.07	20.60	--
Electric Power								
(2006 dollars per short ton)	32.01	33.85	36.62	34.24	33.84	34.03	35.03	0.1%
(2006 dollars per million Btu)	1.59	1.69	1.84	1.74	1.72	1.74	1.78	0.2%
Average	**34.08**	**36.03**	**38.87**	**35.71**	**34.83**	**34.94**	**35.70**	**-0.0%**
Exports[10]	69.22	70.93	80.99	71.83	74.00	76.33	79.44	0.5%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines.
[9]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[10]F.a.s. price at U.S. port of exit.
-- = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 data based on: Energy Information Administration (EIA), *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007); EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007); and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A16. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Electric Power Sector[1]								
Net Summer Capacity								
Conventional Hydropower	76.72	76.72	76.73	77.15	77.26	77.26	77.32	0.0%
Geothermal[2]	2.23	2.29	2.50	2.88	3.28	3.77	4.18	2.5%
Municipal Waste[3]	3.21	3.39	3.99	3.99	4.02	4.06	4.06	0.8%
Wood and Other Biomass[4,5]	1.96	2.01	2.20	2.74	4.39	4.84	5.58	4.3%
Solar Thermal	0.40	0.40	0.54	0.80	0.82	0.84	0.86	3.2%
Solar Photovoltaic[6]	0.03	0.03	0.07	0.14	0.22	0.30	0.39	11.2%
Wind	8.92	11.50	25.61	29.63	33.64	37.18	40.15	5.3%
Total	**93.46**	**96.34**	**111.63**	**117.32**	**123.62**	**128.26**	**132.54**	**1.3%**
Generation (billion kilowatthours)								
Conventional Hydropower	266.91	285.07	289.47	297.22	298.00	298.09	298.53	0.2%
Geothermal[2]	14.69	14.84	17.52	20.79	23.96	27.84	31.05	3.1%
Biogenic Municipal Waste[7]	12.70	13.46	18.85	18.85	19.08	19.46	19.47	1.6%
Wood and Other Biomass[5]	10.57	10.97	22.98	42.96	77.53	83.30	82.55	8.8%
Dedicated Plants	8.60	9.06	11.06	15.46	27.74	30.98	36.64	6.0%
Cofiring	1.97	1.91	11.92	27.51	49.79	52.32	45.91	14.2%
Solar Thermal	0.54	0.49	1.15	1.97	2.04	2.11	2.18	6.4%
Solar Photovoltaic[6]	0.02	0.01	0.16	0.32	0.52	0.74	0.96	19.6%
Wind	17.81	25.78	74.13	87.19	101.23	113.14	123.18	6.7%
Total	**323.23**	**350.62**	**424.27**	**469.30**	**522.35**	**544.68**	**557.91**	**2.0%**
End-Use Generators[8]								
Net Summer Capacity								
Conventional Hydropower[9]	0.71	0.70	0.70	0.70	0.70	0.70	0.70	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Municipal Waste[10]	0.34	0.35	0.35	0.35	0.35	0.35	0.35	0.0%
Biomass	4.72	4.64	4.89	6.37	8.57	12.21	12.60	4.3%
Solar Photovoltaic[6]	0.18	0.27	0.67	0.77	1.13	1.77	2.80	10.2%
Wind	0.01	0.04	0.04	0.05	0.09	0.17	0.26	8.0%
Total	**5.96**	**6.00**	**6.65**	**8.24**	**10.85**	**15.20**	**16.72**	**4.4%**
Generation (billion kilowatthours)								
Conventional Hydropower[9]	3.46	3.24	3.24	3.24	3.24	3.24	3.24	-0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Municipal Waste[10]	1.95	2.06	2.82	2.82	2.82	2.82	2.82	1.3%
Biomass	28.33	28.44	29.98	40.50	57.00	84.74	86.99	4.8%
Solar Photovoltaic[6]	0.28	0.43	1.07	1.25	1.85	2.97	4.76	10.6%
Wind	0.02	0.06	0.06	0.06	0.13	0.24	0.38	8.3%
Total	**34.03**	**34.22**	**37.17**	**47.88**	**65.05**	**94.02**	**98.19**	**4.5%**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2012.
[6]Does not include off-grid PV. Based on annual PV shipments from 1989 through 2005, EIA estimates that as much as 192 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2005, plus an additional 481 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 10.8 (annual PV shipments, 1989-2005). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The Energy Information Administration estimates approximately 7 billion kilowatthours of electricity was generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[8]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[9]Represents own-use industrial hydroelectric power.
[10]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
-- = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2005 and 2006 generation: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Marketed Renewable Energy[2]								
Residential (wood)	0.45	0.41	0.44	0.42	0.40	0.39	0.38	-0.3%
Commercial (biomass)	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.0%
Industrial[3]	1.88	1.99	2.34	2.75	3.32	4.21	4.33	3.3%
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.0%
Municipal Waste[4]	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.0%
Biomass	1.45	1.51	1.48	1.57	1.65	1.75	1.83	0.8%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Transportation	0.35	0.50	1.13	1.66	2.24	2.77	2.77	7.4%
Ethanol used in E85[5]	0.00	0.00	0.00	0.12	0.64	0.93	0.88	33.5%
Ethanol used in Gasoline Blending	0.34	0.47	1.05	1.22	1.18	1.13	1.13	3.7%
Biodiesel used in Distillate Blending	0.01	0.03	0.08	0.17	0.13	0.14	0.16	6.9%
Liquids from Biomass	0.00	0.00	0.00	0.15	0.29	0.56	0.60	--
Electric Power[6]	3.49	3.74	4.53	5.05	5.64	5.94	6.13	2.1%
Conventional Hydroelectric	2.67	2.86	2.89	2.96	2.97	2.97	2.97	0.2%
Geothermal	0.31	0.31	0.37	0.48	0.58	0.70	0.80	4.0%
Biogenic Municipal Waste[7]	0.20	0.15	0.23	0.23	0.23	0.23	0.23	1.8%
Biomass	0.18	0.16	0.28	0.48	0.82	0.87	0.86	7.4%
Dedicated Plants	0.14	0.12	0.12	0.16	0.27	0.30	0.36	4.6%
Cofiring	0.04	0.03	0.16	0.33	0.55	0.57	0.49	11.9%
Solar Thermal	0.01	0.00	0.01	0.02	0.02	0.02	0.02	6.4%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.01	0.01	0.01	19.6%
Wind	0.12	0.26	0.74	0.87	1.02	1.13	1.24	6.7%
Total Marketed Renewable Energy	6.30	6.77	8.56	10.00	11.74	13.44	13.73	3.0%
Sources of Ethanol								
From Corn	0.33	0.41	0.95	1.18	1.26	1.26	1.26	4.8%
From Cellulose	0.00	0.00	0.01	0.03	0.23	0.58	0.58	--
From Other Feedstocks	0.00	0.00	0.00	0.00	0.01	0.02	0.01	--
Net Imports	0.01	0.06	0.09	0.14	0.31	0.19	0.15	4.0%
Total	0.34	0.47	1.05	1.34	1.82	2.06	2.01	6.2%

Table A17. Renewable Energy, Consumption by Sector and Source[1] (Continued)
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Nonmarketed Renewable Energy[8] Selected Consumption								
Residential	**0.01**	**0.02**	**0.02**	**0.03**	**0.04**	**0.05**	**0.07**	**5.9%**
Solar Hot Water Heating	0.01	0.01	0.02	0.02	0.03	0.04	0.05	5.3%
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.01	0.01	6.1%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.01	16.9%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
Commercial	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**1.7%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.7%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.9%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,022 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[5]Excludes motor gasoline component of E85.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The Energy Information Administration estimates approximately .38 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2005 and 2006 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A18. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Residential								
Petroleum	101	100	91	92	92	90	88	-0.5%
Natural Gas	262	237	263	274	281	284	282	0.7%
Coal	1	1	1	1	1	1	1	0.9%
Electricity[1]	890	866	904	913	949	1004	1079	0.9%
Total	**1253**	**1204**	**1259**	**1280**	**1324**	**1379**	**1451**	**0.8%**
Commercial								
Petroleum	52	53	46	48	49	49	49	-0.3%
Natural Gas	169	155	162	175	184	193	201	1.1%
Coal	9	6	8	8	8	8	8	1.0%
Electricity[1]	835	832	864	945	1024	1117	1216	1.6%
Total	**1066**	**1046**	**1079**	**1176**	**1265**	**1367**	**1474**	**1.4%**
Industrial[2]								
Petroleum	412	421	435	442	432	428	436	0.1%
Natural Gas[3]	409	399	430	435	434	437	433	0.3%
Coal	189	189	186	185	204	206	217	0.6%
Electricity[1]	668	642	640	656	649	645	647	0.0%
Total	**1677**	**1652**	**1693**	**1718**	**1718**	**1716**	**1733**	**0.2%**
Transportation								
Petroleum[4]	1948	1952	1940	2010	2032	2062	2145	0.4%
Natural Gas[5]	33	33	36	38	40	43	43	1.2%
Electricity[1]	4	4	4	5	5	5	5	1.2%
Total	**1985**	**1989**	**1980**	**2052**	**2077**	**2110**	**2193**	**0.4%**
Electric Power[6]								
Petroleum	101	55	43	44	45	47	48	-0.5%
Natural Gas	321	340	365	358	323	289	272	-0.9%
Coal	1964	1938	1993	2105	2247	2423	2615	1.3%
Other[7]	12	12	12	12	12	12	12	0.1%
Total	**2397**	**2344**	**2413**	**2519**	**2627**	**2771**	**2948**	**1.0%**
Total by Fuel								
Petroleum[3]	2615	2581	2555	2636	2650	2676	2767	0.3%
Natural Gas	1193	1163	1256	1279	1262	1245	1231	0.2%
Coal	2162	2134	2188	2299	2459	2638	2841	1.2%
Other[7]	12	12	12	12	12	12	12	0.1%
Total	**5982**	**5890**	**6011**	**6226**	**6384**	**6571**	**6851**	**0.6%**
Carbon Dioxide Emissions (tons per person)	**20.1**	**19.6**	**19.3**	**19.2**	**18.9**	**18.7**	**18.7**	**-0.2%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Fuel consumption includes energy for combined heat and power plants (CHP), except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2006, international bunker fuels accounted for 84 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A19. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Real Gross Domestic Product	11004	11319	12453	14199	15984	17951	20219	2.4%
Components of Real Gross Domestic Product								
Real Consumption	7804	8044	8845	10151	11362	12628	13999	2.3%
Real Investment	1869	1920	1939	2307	2614	3088	3743	2.8%
Real Government Spending	1946	1981	2087	2164	2258	2352	2471	0.9%
Real Exports	1203	1304	1797	2455	3387	4582	6191	6.7%
Real Imports	1821	1929	2190	2796	3474	4415	5723	4.6%
Energy Intensity								
(thousand Btu per 2000 dollar of GDP)								
Delivered Energy	6.62	6.39	6.03	5.48	5.00	4.57	4.16	-1.8%
Total Energy	9.09	8.79	8.30	7.54	6.91	6.35	5.80	-1.7%
Price Indices								
GDP Chain-type Price Index (2000=1.000)	1.130	1.166	1.260	1.375	1.520	1.686	1.871	2.0%
Consumer Price Index (1982-4=1.00)								
All-urban	1.95	2.02	2.20	2.38	2.64	2.94	3.29	2.1%
Energy Commodities and Services	1.77	1.97	2.15	2.15	2.43	2.73	3.14	2.0%
Wholesale Price Index (1982=1.00)								
All Commodities	1.57	1.65	1.80	1.84	1.96	2.10	2.26	1.3%
Fuel and Power	1.56	1.67	1.88	1.82	2.04	2.34	2.75	2.1%
Interest Rates (percent, nominal)								
Federal Funds Rate	3.21	4.96	4.69	4.71	4.92	4.85	4.91	--
10-Year Treasury Note	4.29	4.79	5.24	5.20	5.44	5.41	5.46	--
AA Utility Bond Rate	5.44	5.84	6.65	6.71	6.98	7.01	7.13	--
Value of Shipments (billion 2000 dollars)								
Total Industrial	5732	5821	5997	6659	7113	7546	7997	1.3%
Nonmanufacturing	1525	1531	1419	1583	1619	1663	1715	0.5%
Manufacturing	4208	4290	4577	5076	5493	5883	6283	1.6%
Energy-Intensive	1207	1225	1283	1351	1387	1418	1447	0.7%
Non-energy Intensive	3001	3065	3295	3725	4107	4465	4836	1.9%
Population and Employment (millions)								
Population, with Armed Forces Overseas	297.3	300.1	310.9	324.3	337.7	351.4	365.6	0.8%
Population, aged 16 and over	232.2	235.0	244.9	255.3	266.0	277.3	289.3	0.9%
Population, over age 65	36.9	37.3	40.4	47.0	54.9	63.8	71.6	2.8%
Employment, Nonfarm	133.6	136.1	142.4	149.7	154.5	160.9	168.1	0.9%
Employment, Manufacturing	14.2	14.2	14.2	14.4	13.8	12.5	11.2	-1.0%
Key Labor Indicators								
Labor Force (millions)	149.3	151.4	156.8	162.1	165.6	171.0	177.9	0.7%
Nonfarm Labor Productivity (1992=1.00)	1.34	1.35	1.45	1.60	1.77	1.95	2.14	1.9%
Unemployment Rate (percent)	5.07	4.63	5.03	4.58	4.62	4.79	4.80	--
Key Indicators for Energy Demand								
Real Disposable Personal Income	8148	8397	9472	11055	12654	14349	16246	2.8%
Housing Starts (millions)	2.22	1.93	1.68	1.88	1.78	1.74	1.70	-0.5%
Commercial Floorspace (billion square feet)	73.8	74.8	78.8	83.9	89.3	94.8	100.8	1.2%
Unit Sales of Light-Duty Vehicles (millions)	16.95	16.50	16.38	17.75	17.47	18.35	19.39	0.7%

GDP = Gross domestic product.
Btu = British thermal unit.
-- = Not applicable.
Sources: 2005 and 2006: Global Insight, Global Insight Industry and Employment models, July 2007. **Projections:** Energy Information Administration, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A20. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Crude Oil Prices (2006 dollars per barrel)								
Imported Low Sulfur Light Crude Oil	58.28	66.02	74.03	59.85	59.70	64.49	70.45	0.3%
Imported Crude Oil[1]	50.40	59.05	65.18	52.03	51.55	55.68	58.66	-0.0%
Conventional Production (Conventional)[2]								
OPEC[3]								
Asia	1.15	1.11	1.03	0.99	0.98	0.99	0.94	-0.7%
Middle East	22.50	23.21	22.41	23.40	24.09	25.24	27.35	0.7%
North Africa	3.81	3.90	4.28	4.63	4.78	4.84	4.82	0.9%
West Africa	4.03	4.02	5.77	6.88	7.41	7.80	8.23	3.0%
South America	2.21	2.06	1.99	2.20	2.18	2.17	2.16	0.2%
Total OPEC	**33.71**	**34.30**	**35.48**	**38.09**	**39.45**	**41.04**	**43.50**	**1.0%**
Non-OPEC								
OECD								
United States (50 states)	8.04	7.91	8.84	9.12	9.15	8.84	8.39	0.2%
Canada	1.99	2.00	1.85	1.56	1.32	1.16	1.05	-2.7%
Mexico	3.79	3.74	3.37	3.29	3.25	3.24	3.35	-0.5%
OECD Europe[4]	5.94	5.52	4.89	4.05	3.59	3.43	3.39	-2.0%
Japan	0.13	0.13	0.12	0.13	0.14	0.15	0.15	0.8%
Australia and New Zealand	0.59	0.57	0.62	0.64	0.65	0.66	0.66	0.6%
Total OECD	**20.48**	**19.85**	**19.69**	**18.78**	**18.10**	**17.48**	**16.99**	**-0.6%**
Non-OECD								
Russia	9.58	9.82	10.34	10.60	10.90	11.37	11.69	0.7%
Other Eurasia[5]	2.65	2.85	3.77	4.83	5.46	5.88	6.36	3.4%
China	3.74	3.80	3.83	3.87	3.87	3.70	3.53	-0.3%
Other Asia[6]	2.77	2.89	2.92	3.22	3.40	3.43	3.17	0.4%
Middle East[7]	1.67	1.69	2.00	2.20	2.40	2.70	2.90	2.3%
Africa	2.47	2.49	2.92	3.35	3.83	4.04	3.99	2.0%
Brazil	1.75	1.84	2.40	2.94	3.39	3.65	3.66	2.9%
Other Central and South America	2.36	2.36	2.32	2.49	2.67	3.03	3.51	1.7%
Total Non-OECD	**26.98**	**27.73**	**30.51**	**33.49**	**35.94**	**37.80**	**38.81**	**1.4%**
Total Conventional Production	**81.17**	**81.88**	**85.67**	**90.37**	**93.48**	**96.31**	**99.30**	**0.8%**
Unconventional Production[8]								
United States (50 states)	0.26	0.34	0.78	1.15	1.53	1.97	2.06	7.9%
Other North America	1.09	1.23	1.91	2.34	2.85	3.41	3.96	5.0%
OECD Europe[3]	0.03	0.04	0.07	0.10	0.15	0.19	0.26	8.4%
Middle East[7]	0.00	0.00	0.03	0.18	0.31	0.62	1.24	25.8%
Africa	0.15	0.17	0.31	0.36	0.44	0.59	0.83	6.9%
Central and South America	0.79	0.80	1.18	1.45	1.76	2.09	2.51	4.9%
Other	0.16	0.20	0.44	0.76	1.28	1.96	3.15	12.1%
Total Unconventional Production	**2.48**	**2.78**	**4.73**	**6.34**	**8.32**	**10.83**	**14.00**	**7.0%**
Total Production	**83.65**	**84.66**	**90.40**	**96.70**	**101.80**	**107.14**	**113.31**	**1.2%**

Table A20. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Consumption[9]								
OECD								
United States (50 states)	20.80	20.65	20.99	21.59	21.47	21.52	22.11	0.3%
United States Territories	0.37	0.38	0.43	0.47	0.51	0.55	0.59	1.9%
Canada	2.26	2.27	2.32	2.34	2.36	2.38	2.40	0.2%
Mexico	2.03	2.06	2.19	2.36	2.61	2.75	2.95	1.5%
OECD Europe[3]	15.42	15.42	15.47	15.63	15.71	15.79	15.86	0.1%
Japan	5.16	5.16	5.18	5.21	5.22	5.24	5.26	0.1%
South Korea	2.17	2.18	2.25	2.47	2.57	2.68	2.81	1.1%
Australia and New Zealand	1.03	1.03	1.07	1.13	1.19	1.25	1.28	0.9%
Total OECD	**49.24**	**49.16**	**49.90**	**51.20**	**51.64**	**52.16**	**53.28**	**0.3%**
Non-OECD								
Russia	2.77	2.79	2.89	3.03	3.13	3.25	3.32	0.7%
Other Non-OECD Eurasia[5]	2.05	2.09	2.26	2.43	2.64	2.79	2.96	1.5%
China	6.73	7.26	9.44	10.55	11.96	13.63	15.69	3.3%
India	2.44	2.49	2.68	3.25	3.62	4.03	4.37	2.4%
Other Non-OECD Asia	6.02	6.14	6.67	7.64	8.35	9.08	9.86	2.0%
Middle East[7]	5.91	6.15	7.13	7.79	8.46	9.18	9.84	2.0%
Africa	2.90	2.99	3.36	3.88	4.35	4.62	4.93	2.1%
Brazil	2.40	2.34	2.57	2.87	3.15	3.42	3.68	1.9%
Other Central and South America	3.17	3.26	3.51	4.05	4.51	4.98	5.37	2.1%
Total Non-OECD	**34.41**	**35.51**	**40.51**	**45.50**	**50.16**	**54.98**	**60.02**	**2.2%**
Total Consumption	**83.65**	**84.66**	**90.40**	**96.70**	**101.80**	**107.14**	**113.30**	**1.2%**
OPEC Production[10]	34.31	34.90	36.40	39.26	40.87	42.91	46.16	1.2%
Non-OPEC Production[10]	49.34	49.76	54.00	57.44	60.94	64.23	67.15	1.3%
Net Eurasia Exports	9.15	9.63	11.37	12.91	13.98	14.86	15.43	2.0%
OPEC Market Share (percent)	41.0	41.2	40.3	40.6	40.1	40.0	40.7	-0.0%

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela. Does not include Ecuador, which was admitted to OPEC as a full member on November 17, 2007.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Eurasia consists of Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2005 and 2006 imported crude oil price: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 quantities derived from: EIA, *International Energy Annual 2005*, DOE/EIA-0219(2005) (Washington, DC, June-October 2007). **2006 quantities and projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Economic Growth Case Comparisons

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	10.80	12.75	12.76	12.77	13.38	13.40	13.52	11.87	12.04	12.18
Natural Gas Plant Liquids	2.36	2.26	2.27	2.29	2.25	2.31	2.36	2.01	2.11	2.20
Dry Natural Gas	19.04	19.53	19.85	20.13	19.50	20.24	20.63	19.07	20.00	21.10
Coal[1]	23.79	23.95	23.97	24.00	23.63	25.20	27.23	25.47	28.63	32.20
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.92
Hydropower	2.89	2.92	2.92	2.92	2.99	3.00	3.00	2.99	3.00	3.00
Biomass[2]	2.94	4.02	4.05	4.10	6.29	6.42	6.61	7.84	8.12	8.53
Other Renewable Energy[3]	0.88	1.46	1.51	1.51	1.78	2.00	2.08	2.09	2.45	2.61
Other[4]	0.50	0.53	0.54	0.54	0.59	0.58	0.58	0.64	0.64	0.65
Total	71.41	75.71	76.17	76.56	79.31	82.21	85.27	80.71	86.56	93.39
Imports										
Crude Oil	22.08	20.76	21.14	21.33	20.61	21.58	22.36	22.66	24.41	25.77
Liquid Fuels and Other Petroleum[5]	7.21	5.44	5.61	6.02	4.61	5.43	6.41	3.90	5.44	6.93
Natural Gas	4.29	4.70	4.80	4.89	4.42	4.68	4.93	4.16	4.64	4.80
Other Imports[6]	0.98	0.94	0.95	0.95	1.96	1.93	1.95	2.80	2.74	2.85
Total	34.57	31.84	32.49	33.20	31.60	33.62	35.65	33.52	37.22	40.36
Exports										
Petroleum[7]	2.60	2.83	2.82	2.84	3.00	2.98	3.00	3.42	3.33	3.11
Natural Gas	0.73	0.85	0.84	0.84	1.05	1.02	1.00	1.43	1.36	1.30
Coal	1.26	1.79	1.79	1.79	0.88	0.87	0.86	0.88	0.88	0.88
Total	4.59	5.47	5.45	5.47	4.93	4.87	4.86	5.73	5.56	5.29
Discrepancy[8]	1.87	-0.10	-0.13	-0.17	0.17	0.12	0.02	0.29	0.21	0.07
Consumption										
Liquid Fuels and Other Petroleum[9]	40.06	39.85	40.46	41.12	40.15	42.24	44.43	40.08	43.99	48.01
Natural Gas	22.30	23.51	23.93	24.31	22.99	24.01	24.68	21.91	23.39	24.71
Coal[10]	22.50	23.00	23.03	23.06	24.48	25.87	27.74	27.00	29.90	32.99
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.92
Hydropower	2.89	2.92	2.92	2.92	2.99	3.00	3.00	2.99	3.00	3.00
Biomass[11]	2.50	2.97	3.01	3.06	4.35	4.50	4.69	5.23	5.51	5.94
Other Renewable Energy[3]	0.88	1.46	1.51	1.51	1.78	2.00	2.08	2.09	2.45	2.61
Other[12]	0.19	0.18	0.18	0.18	0.17	0.17	0.17	0.18	0.20	0.20
Total	99.52	102.19	103.34	104.46	105.82	110.85	116.04	108.21	118.01	128.38

Table B1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Prices (2006 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price	66.02	73.52	74.03	74.56	58.73	59.70	60.62	68.43	70.45	72.15
Imported Crude Oil Price[13]	59.05	64.48	65.18	66.21	50.37	51.55	52.42	55.52	58.66	62.27
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.73	6.69	6.90	7.11	5.72	5.95	5.93	6.84	7.22	7.61
Wellhead Price[14]	6.24	5.96	6.16	6.35	5.08	5.29	5.27	6.10	6.45	6.80
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.42	6.13	6.33	6.53	5.22	5.44	5.43	6.27	6.63	7.00
Coal (dollars per ton)										
Minemouth Price[15]	24.63	26.02	26.16	26.33	22.24	22.51	23.16	22.15	23.32	24.09
Coal (dollars per million Btu)										
Minemouth Price[15]	1.21	1.27	1.28	1.29	1.12	1.14	1.18	1.13	1.19	1.24
Average Delivered Price[16]	1.78	1.92	1.93	1.94	1.74	1.77	1.81	1.76	1.82	1.87
Average Electricity Price (cents per kilowatthour)	8.9	9.1	9.2	9.3	8.3	8.6	8.7	8.6	8.8	9.1

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LM2008.D031608A, AEO2008.D030208F, and HM2008.D031608A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.47	0.48	0.48	0.48	0.51	0.52	0.53	0.52	0.55	0.58
Kerosene	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.08	0.09
Distillate Fuel Oil	0.70	0.76	0.75	0.75	0.73	0.73	0.73	0.65	0.65	0.65
Liquid Fuels and Other Petroleum Subtotal	1.25	1.31	1.31	1.32	1.32	1.33	1.35	1.26	1.29	1.32
Natural Gas	4.50	4.94	4.95	4.96	5.18	5.30	5.44	5.07	5.32	5.57
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.41	0.44	0.44	0.44	0.40	0.40	0.41	0.36	0.38	0.39
Electricity	4.61	4.93	4.95	4.97	5.10	5.25	5.41	5.52	5.88	6.22
Delivered Energy	**10.77**	**11.63**	**11.66**	**11.69**	**12.01**	**12.30**	**12.63**	**12.23**	**12.88**	**13.52**
Electricity Related Losses	10.04	10.58	10.59	10.60	10.81	11.08	11.36	11.54	12.14	12.74
Total	**20.82**	**22.22**	**22.25**	**22.29**	**22.82**	**23.39**	**23.99**	**23.77**	**25.01**	**26.25**
Commercial										
Liquefied Petroleum Gases	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.42	0.38	0.38	0.38	0.41	0.41	0.42	0.40	0.41	0.42
Residual Fuel Oil	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Liquid Fuels and Other Petroleum Subtotal	0.68	0.63	0.63	0.63	0.67	0.68	0.69	0.67	0.68	0.70
Natural Gas	2.92	3.02	3.04	3.06	3.34	3.47	3.60	3.54	3.78	4.03
Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Renewable Energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.43	4.69	4.73	4.75	5.49	5.67	5.84	6.24	6.62	7.01
Delivered Energy	**8.25**	**8.56**	**8.62**	**8.65**	**9.71**	**10.03**	**10.34**	**10.66**	**11.30**	**11.95**
Electricity Related Losses	9.66	10.07	10.12	10.14	11.63	11.96	12.26	13.04	13.68	14.34
Total	**17.91**	**18.63**	**18.74**	**18.80**	**21.34**	**21.98**	**22.60**	**23.70**	**24.98**	**26.29**
Industrial[4]										
Liquefied Petroleum Gases	2.09	2.07	2.12	2.18	1.65	1.83	2.04	1.40	1.71	2.05
Motor Gasoline[2]	0.38	0.36	0.38	0.39	0.34	0.37	0.41	0.33	0.38	0.43
Distillate Fuel Oil	1.28	1.24	1.29	1.34	1.12	1.23	1.34	1.07	1.23	1.40
Residual Fuel Oil	0.28	0.27	0.28	0.29	0.22	0.23	0.24	0.20	0.23	0.25
Petrochemical Feedstocks	1.41	1.32	1.36	1.41	1.22	1.39	1.57	1.01	1.29	1.60
Other Petroleum[5]	4.48	4.11	4.25	4.38	3.99	4.22	4.48	4.02	4.41	4.79
Liquid Fuels and Other Petroleum Subtotal	9.92	9.38	9.67	9.98	8.53	9.27	10.07	8.03	9.25	10.53
Natural Gas	6.68	7.03	7.16	7.24	6.67	7.14	7.60	6.14	7.08	7.94
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.17	1.20	1.21	1.22	1.22	1.25	1.27	1.23	1.27	1.32
Natural Gas Subtotal	7.85	8.23	8.37	8.47	7.89	8.39	8.87	7.37	8.35	9.26
Metallurgical Coal	0.60	0.59	0.60	0.61	0.49	0.54	0.58	0.39	0.48	0.57
Other Industrial Coal	1.26	1.29	1.31	1.32	1.15	1.20	1.24	1.10	1.18	1.25
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.15	0.34	0.58	0.34	0.55	1.27
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.02	0.04	0.06
Coal Subtotal	1.92	1.91	1.93	1.96	1.82	2.11	2.45	1.84	2.26	3.15
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.67	1.50	1.49	1.49	2.34	2.31	2.29
Renewable Energy[7]	1.69	1.62	1.66	1.71	1.70	1.83	1.98	1.71	2.02	2.33
Electricity	3.42	3.44	3.50	3.57	3.32	3.59	3.87	2.94	3.52	4.10
Delivered Energy	**25.10**	**25.26**	**25.82**	**26.36**	**24.75**	**26.70**	**28.73**	**24.23**	**27.70**	**31.67**
Electricity Related Losses	7.45	7.38	7.50	7.62	7.03	7.57	8.13	6.14	7.28	8.39
Total	**32.55**	**32.64**	**33.32**	**33.98**	**31.78**	**34.27**	**36.86**	**30.37**	**34.98**	**40.06**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Liquefied Petroleum Gases	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.02
E85[8]	0.00	0.00	0.00	0.00	1.07	0.97	0.95	1.53	1.34	1.26
Motor Gasoline[2]	17.20	17.13	17.25	17.40	15.81	16.56	17.32	14.66	15.97	17.34
Jet Fuel[9]	3.16	3.41	3.44	3.47	4.10	4.15	4.13	4.62	4.79	4.83
Distillate Fuel Oil[10]	6.18	6.38	6.54	6.72	7.05	7.63	8.26	7.67	8.98	10.30
Residual Fuel Oil	0.83	0.85	0.85	0.86	0.85	0.86	0.87	0.86	0.87	0.88
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[11]	0.18	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.19
Liquid Fuels and Other Petroleum Subtotal	27.57	27.97	28.29	28.63	29.06	30.37	31.72	29.53	32.15	34.82
Pipeline Fuel Natural Gas	0.59	0.63	0.64	0.65	0.66	0.69	0.71	0.68	0.72	0.76
Compressed Natural Gas	0.02	0.03	0.04	0.04	0.06	0.07	0.08	0.07	0.08	0.10
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Delivered Energy	**28.20**	**28.66**	**28.98**	**29.34**	**29.81**	**31.15**	**32.53**	**30.31**	**32.98**	**35.71**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Total	**28.25**	**28.70**	**29.03**	**29.39**	**29.87**	**31.21**	**32.59**	**30.38**	**33.04**	**35.77**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.65	2.65	2.70	2.76	2.26	2.45	2.68	2.03	2.37	2.75
E85[8]	0.00	0.00	0.00	0.00	1.07	0.97	0.95	1.53	1.34	1.26
Motor Gasoline[2]	17.62	17.54	17.68	17.84	16.20	16.99	17.78	15.04	16.40	17.83
Jet Fuel[9]	3.16	3.41	3.44	3.47	4.10	4.15	4.13	4.62	4.79	4.83
Kerosene	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.12	0.13	0.13
Distillate Fuel Oil	8.59	8.76	8.97	9.19	9.31	10.00	10.74	9.80	11.28	12.77
Residual Fuel Oil	1.23	1.22	1.23	1.24	1.17	1.19	1.21	1.15	1.20	1.24
Petrochemical Feedstocks	1.41	1.32	1.36	1.41	1.22	1.39	1.57	1.01	1.29	1.60
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.64	4.27	4.40	4.54	4.14	4.38	4.64	4.18	4.56	4.96
Liquid Fuels and Other Petroleum Subtotal	39.41	39.30	39.90	40.56	39.58	41.65	43.83	39.49	43.37	47.37
Natural Gas	14.12	15.03	15.19	15.30	15.25	15.98	16.72	14.82	16.27	17.64
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.17	1.20	1.21	1.22	1.22	1.25	1.27	1.23	1.27	1.32
Pipeline Natural Gas	0.59	0.63	0.64	0.65	0.66	0.69	0.71	0.68	0.72	0.76
Natural Gas Subtotal	15.88	16.86	17.04	17.17	17.13	17.93	18.70	16.73	18.26	19.73
Metallurgical Coal	0.60	0.59	0.60	0.61	0.49	0.54	0.58	0.39	0.48	0.57
Other Coal	1.35	1.38	1.40	1.41	1.24	1.29	1.33	1.19	1.27	1.34
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.15	0.34	0.58	0.34	0.55	1.27
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.02	0.04	0.06
Coal Subtotal	2.02	2.00	2.03	2.05	1.92	2.21	2.54	1.93	2.35	3.25
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.67	1.50	1.49	1.49	2.34	2.31	2.29
Renewable Energy[13]	2.23	2.19	2.23	2.28	2.22	2.37	2.52	2.21	2.52	2.85
Electricity	12.49	13.08	13.20	13.31	13.93	14.54	15.16	14.74	16.05	17.36
Delivered Energy	**72.32**	**74.10**	**75.08**	**76.05**	**76.28**	**80.18**	**84.23**	**77.43**	**84.86**	**92.85**
Electricity Related Losses	27.19	28.08	28.26	28.41	29.54	30.67	31.81	30.78	33.16	35.54
Total	**99.52**	**102.19**	**103.34**	**104.46**	**105.82**	**110.85**	**116.04**	**108.21**	**118.01**	**128.38**
Electric Power[14]										
Distillate Fuel Oil	0.18	0.18	0.18	0.18	0.18	0.20	0.21	0.20	0.23	0.24
Residual Fuel Oil	0.46	0.38	0.38	0.38	0.38	0.39	0.39	0.39	0.40	0.41
Liquid Fuels and Other Petroleum Subtotal	0.64	0.55	0.56	0.56	0.56	0.59	0.60	0.59	0.63	0.64
Natural Gas	6.42	6.64	6.89	7.14	5.86	6.09	5.97	5.18	5.13	4.99
Steam Coal	20.48	21.00	21.01	21.01	22.57	23.67	25.20	25.07	27.55	29.75
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.92
Renewable Energy[15]	3.74	4.48	4.53	4.52	5.41	5.64	5.75	5.77	6.13	6.40
Electricity Imports	0.06	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.08	0.07
Total[16]	**39.68**	**41.16**	**41.46**	**41.72**	**43.47**	**45.21**	**46.96**	**45.52**	**49.21**	**52.90**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Energy Consumption										
Liquefied Petroleum Gases	2.65	2.65	2.70	2.76	2.26	2.45	2.68	2.03	2.37	2.75
E85[8]	0.00	0.00	0.00	0.00	1.07	0.97	0.95	1.53	1.34	1.26
Motor Gasoline[2]	17.62	17.54	17.68	17.84	16.20	16.99	17.78	15.04	16.40	17.83
Jet Fuel[9]	3.16	3.41	3.44	3.47	4.10	4.15	4.13	4.62	4.79	4.83
Kerosene	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.12	0.13	0.13
Distillate Fuel Oil	8.77	8.94	9.15	9.37	9.49	10.20	10.96	10.01	11.51	13.01
Residual Fuel Oil	1.69	1.60	1.60	1.62	1.55	1.58	1.60	1.54	1.60	1.65
Petrochemical Feedstocks	1.41	1.32	1.36	1.41	1.22	1.39	1.57	1.01	1.29	1.60
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.64	4.27	4.40	4.54	4.14	4.38	4.64	4.18	4.56	4.96
Liquid Fuels and Other Petroleum Subtotal	40.06	39.85	40.46	41.12	40.15	42.24	44.43	40.08	43.99	48.01
Natural Gas	20.54	21.68	22.08	22.44	21.10	22.07	22.70	20.00	21.40	22.63
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.17	1.20	1.21	1.22	1.22	1.25	1.27	1.23	1.27	1.32
Pipeline Natural Gas	0.59	0.63	0.64	0.65	0.66	0.69	0.71	0.68	0.72	0.76
Natural Gas Subtotal	22.30	23.51	23.93	24.31	22.99	24.01	24.68	21.91	23.39	24.71
Metallurgical Coal	0.60	0.59	0.60	0.61	0.49	0.54	0.58	0.39	0.48	0.57
Other Coal	21.83	22.38	22.41	22.42	23.81	24.96	26.53	26.26	28.82	31.09
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.15	0.34	0.58	0.34	0.55	1.27
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.02	0.04	0.06
Coal Subtotal	22.50	23.00	23.03	23.06	24.48	25.87	27.74	27.00	29.90	32.99
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.92
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.67	1.50	1.49	1.49	2.34	2.31	2.29
Renewable Energy[17]	5.97	6.67	6.76	6.81	7.63	8.01	8.27	7.98	8.66	9.25
Electricity Imports	0.06	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.08	0.07
Total	**99.52**	**102.19**	**103.34**	**104.46**	**105.82**	**110.85**	**116.04**	**108.21**	**118.01**	**128.38**
Energy Use and Related Statistics										
Delivered Energy Use	72.32	74.10	75.08	76.05	76.28	80.18	84.23	77.43	84.86	92.85
Total Energy Use	99.52	102.19	103.34	104.46	105.82	110.85	116.04	108.21	118.01	128.38
Ethanol Consumed in Motor Gasoline and E85	0.47	1.04	1.05	1.05	1.82	1.82	1.82	2.04	2.01	2.01
Population (millions)	300.13	309.46	310.85	312.64	325.45	337.74	351.32	336.65	365.59	396.34
Gross Domestic Product (billion 2000 dollars)	11319	12110	12453	12797	14743	15984	17239	17429	20219	23002
Carbon Dioxide Emissions (million metric tons)	5890.3	5953.4	6010.6	6068.7	6076.9	6384.1	6720.8	6263.6	6851.0	7452.0

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2006 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 population and gross domestic product: Global Insight, Global Insight Industry and Employment models, July 2007. 2006 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LM2008.D031608A, AEO2008.D030208F, and HM2008.D031608A.

Table B3. Energy Prices by Sector and Source
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Liquefied Petroleum Gases	23.08	25.00	25.21	25.41	23.99	24.23	24.25	25.03	25.43	25.85
Distillate Fuel Oil	17.94	16.74	17.21	17.48	13.96	14.27	14.71	15.20	16.27	17.12
Natural Gas	13.40	11.95	12.15	12.36	11.14	11.39	11.44	12.47	12.91	13.36
Electricity	30.52	30.99	31.37	31.75	29.19	30.20	30.75	29.59	30.63	31.72
Commercial										
Distillate Fuel Oil	14.59	14.78	15.24	15.51	12.88	13.24	13.81	13.96	15.00	16.08
Residual Fuel Oil	8.60	9.95	10.06	10.17	7.73	7.95	8.11	8.52	9.22	9.80
Natural Gas	11.50	10.41	10.59	10.79	9.72	9.91	9.89	11.13	11.43	11.75
Electricity	27.75	27.46	27.89	28.32	24.63	25.64	26.14	25.22	26.17	27.20
Industrial[1]										
Liquefied Petroleum Gases	19.71	17.58	17.74	17.93	16.65	16.79	16.71	17.60	17.79	18.16
Distillate Fuel Oil	15.33	15.27	15.72	15.99	14.21	14.62	15.23	15.21	16.26	17.47
Residual Fuel Oil	9.06	10.51	10.86	11.10	7.96	8.29	8.65	8.84	9.62	10.61
Natural Gas[2]	7.66	7.02	7.21	7.41	6.00	6.21	6.20	6.95	7.29	7.65
Metallurgical Coal	3.54	4.06	4.07	4.09	3.38	3.42	3.45	3.54	3.60	3.67
Other Industrial Coal	2.34	2.41	2.42	2.43	2.24	2.28	2.34	2.26	2.33	2.41
Coal to Liquids	--	--	--	--	0.94	1.09	1.27	1.20	1.30	1.39
Electricity	17.97	18.88	19.21	19.56	16.49	17.27	17.59	16.93	17.63	18.24
Transportation										
Liquefied Petroleum Gases[3]	21.72	25.82	26.03	26.24	24.70	24.94	24.95	25.64	26.03	26.44
E85[4]	24.81	22.26	23.58	23.84	18.66	18.15	19.83	18.85	19.62	21.43
Motor Gasoline[5]	21.19	20.80	21.23	21.47	18.98	19.64	19.96	19.29	20.37	21.58
Jet Fuel[6]	14.83	15.33	15.77	16.03	13.02	13.27	13.54	14.37	15.37	16.36
Distillate Fuel Oil[7]	19.72	19.21	19.68	19.96	17.74	18.26	19.03	18.43	19.59	21.01
Residual Fuel Oil	7.89	10.22	10.53	10.81	8.30	8.69	9.04	9.55	10.39	11.21
Natural Gas[8]	14.28	13.37	13.60	13.83	11.79	12.15	12.32	12.27	12.83	13.45
Electricity	29.73	30.39	30.95	31.46	27.97	29.05	29.40	28.89	29.65	30.46
Electric Power[9]										
Distillate Fuel Oil	13.35	13.16	13.62	13.91	10.37	10.69	11.16	11.66	12.71	13.54
Residual Fuel Oil	8.17	9.18	9.45	9.70	7.14	7.50	7.83	8.25	9.04	9.90
Natural Gas	6.87	6.76	6.96	7.17	5.73	5.95	5.93	6.64	6.93	7.27
Steam Coal	1.69	1.83	1.84	1.84	1.69	1.72	1.76	1.72	1.78	1.85
Average Price to All Users[10]										
Liquefied Petroleum Gases	20.35	19.13	19.27	19.44	18.53	18.59	18.42	19.77	19.82	20.01
E85[4]	24.81	22.26	23.58	23.84	18.66	18.15	19.83	18.85	19.62	21.43
Motor Gasoline[5]	21.06	20.79	21.23	21.47	18.98	19.64	19.96	19.29	20.37	21.57
Jet Fuel	14.83	15.33	15.77	16.03	13.02	13.27	13.54	14.37	15.37	16.36
Distillate Fuel Oil	18.56	18.00	18.48	18.77	16.69	17.20	17.92	17.55	18.74	20.15
Residual Fuel Oil	8.21	10.01	10.31	10.57	7.93	8.29	8.62	9.06	9.87	10.71
Natural Gas	9.22	8.55	8.72	8.89	7.80	7.98	7.99	9.03	9.36	9.73
Metallurgical Coal	3.54	4.06	4.07	4.09	3.38	3.42	3.45	3.54	3.60	3.67
Other Coal	1.73	1.87	1.88	1.88	1.72	1.75	1.79	1.74	1.81	1.87
Coal to Liquids	--	--	--	--	0.94	1.09	1.27	1.20	1.30	1.39
Electricity	26.10	26.54	26.90	27.25	24.37	25.23	25.61	25.21	25.93	26.71

Table B3. Energy Prices by Sector and Source (Continued)
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Non-Renewable Energy Expenditures by Sector (billion 2006 dollars)										
Residential	225.38	237.66	241.71	245.66	230.03	243.22	253.57	250.85	274.70	299.44
Commercial	166.54	170.25	174.38	177.99	176.99	189.37	198.43	206.78	227.37	249.73
Industrial	205.11	214.18	224.65	235.03	170.98	193.16	213.17	161.83	203.93	249.45
Transportation	542.63	542.10	560.74	574.98	488.82	530.80	570.19	502.22	587.86	684.41
Total Non-Renewable Expenditures	1139.66	1164.20	1201.48	1233.66	1066.82	1156.54	1235.36	1121.67	1293.86	1483.04
Transportation Renewable Expenditures	0.03	0.07	0.06	0.07	19.95	17.64	18.92	28.91	26.35	26.92
Total Expenditures	**1139.70**	**1164.27**	**1201.54**	**1233.72**	**1086.77**	**1174.18**	**1254.28**	**1150.58**	**1320.22**	**1509.95**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2006 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 transportation sector natural gas delivered prices are model results. 2006 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2006 through April 2007. 2006 coal prices based on: EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007) and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. 2006 electricity prices: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2008 National Energy Modeling System runs LM2008.D031608A, AEO2008.D030208F, and HM2008.D031608A.

Economic Growth Case Comparisons

Table B4. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Real Gross Domestic Product	11319	12110	12453	12797	14743	15984	17239	17429	20219	23002
Components of Real Gross Domestic Product										
Real Consumption	8044	8670	8845	9021	10568	11362	12169	12323	13999	15679
Real Investment	1920	1763	1939	2114	2314	2614	2914	3000	3743	4477
Real Government Spending	1981	2055	2087	2118	2118	2258	2398	2167	2471	2772
Real Exports	1304	1784	1797	1809	3059	3387	3720	5218	6191	7170
Real Imports	1929	2143	2190	2246	3326	3474	3589	5386	5723	6008
Energy Intensity (thousand Btu per 2000 dollar of GDP)										
Delivered Energy	6.39	6.12	6.03	5.94	5.15	5.00	4.87	4.41	4.16	4.01
Total Energy	8.79	8.44	8.30	8.16	7.16	6.91	6.71	6.17	5.80	5.55
Price Indices										
GDP Chain-Type Price Index (2000=1.000)	1.166	1.274	1.260	1.245	1.642	1.520	1.400	2.122	1.871	1.630
Consumer Price Index (1982-4=1)										
All-Urban	2.02	2.22	2.20	2.17	2.86	2.64	2.43	3.72	3.29	2.88
Energy Commodities and Services	1.97	2.14	2.15	2.15	2.54	2.43	2.29	3.40	3.14	2.88
Wholesale Price Index (1982=1.00)										
All Commodities	1.65	1.82	1.80	1.77	2.15	1.96	1.78	2.64	2.26	1.91
Fuel and Power	1.67	1.86	1.88	1.89	2.14	2.04	1.92	2.98	2.75	2.51
Interest Rates (percent, nominal)										
Federal Funds Rate	4.96	4.96	4.69	4.40	5.42	4.92	4.45	5.46	4.91	4.37
10-Year Treasury Note	4.79	5.56	5.24	4.89	5.99	5.44	4.90	6.08	5.46	4.89
AA Utility Bond Rate	5.84	6.84	6.65	6.44	7.52	6.98	6.45	7.76	7.13	6.54
Value of Shipments (billion 2000 dollars)										
Total Industrial	5821	5788	5997	6202	6447	7113	7768	6533	7997	9450
Non-manufacturing	1531	1324	1419	1515	1427	1619	1814	1440	1715	1988
Manufacturing	4290	4464	4577	4687	5020	5493	5953	5092	6283	7462
Energy-Intensive	1225	1257	1283	1309	1287	1387	1487	1251	1447	1643
Non-Energy Intensive	3065	3207	3295	3378	3733	4107	4466	3842	4836	5819
Population and Employment (millions)										
Population with Armed Forces Overseas	300.1	309.5	310.9	312.6	325.4	337.7	351.3	336.7	365.6	396.3
Population (aged 16 and over)	235.0	243.5	244.9	246.7	257.6	266.0	275.2	270.4	289.3	309.4
Population, over age 65	37.3	40.3	40.4	40.6	54.0	54.9	55.8	69.3	71.6	74.1
Employment, Nonfarm	136.1	137.3	142.4	147.6	143.5	154.5	165.7	152.9	168.1	183.2
Employment, Manufacturing	14.2	14.0	14.2	14.3	13.3	13.8	14.2	10.1	11.2	12.0
Key Labor Indicators										
Labor Force (millions)	151.4	155.1	156.8	158.3	160.3	165.6	171.6	168.5	177.9	187.6
Non-farm Labor Productivity (1992=1.00)	1.35	1.44	1.45	1.47	1.68	1.77	1.87	1.92	2.14	2.37
Unemployment Rate (percent)	4.63	5.12	5.03	4.93	4.80	4.62	4.41	4.99	4.80	4.68
Key Indicators for Energy Demand										
Real Disposable Personal Income	8397	9284	9472	9661	11888	12654	13436	14627	16246	17874
Housing Starts (millions)	1.93	1.42	1.68	1.93	1.39	1.78	2.17	1.15	1.70	2.24
Commercial Floorspace (billion square feet)	74.8	78.0	78.8	79.4	85.6	89.3	92.6	93.8	100.8	108.0
Unit Sales of Light-Duty Vehicles (millions)	16.50	16.05	16.38	17.09	16.36	17.47	18.88	17.16	19.39	21.86

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2006: Global Insight, Global Insight Industry and Employment models, July 2007. **Projections:** Energy Information Administration, AEO2008 National Energy Modeling System runs LM2008.D031608A, AEO2008.D030208F, and HM2008.D031608A.

Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Production										
Crude Oil and Lease Condensate	10.80	12.85	12.76	12.64	13.67	13.40	13.57	11.15	12.04	13.71
Natural Gas Plant Liquids	2.36	2.27	2.27	2.26	2.32	2.31	2.28	2.09	2.11	2.11
Dry Natural Gas	19.04	19.83	19.85	19.81	20.14	20.24	20.26	19.98	20.00	20.36
Coal[1]	23.79	23.97	23.97	23.97	23.33	25.20	26.13	25.88	28.63	32.46
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.66
Hydropower	2.89	2.92	2.92	2.92	3.00	3.00	3.01	3.01	3.00	3.01
Biomass[2]	2.94	4.08	4.05	4.02	6.48	6.42	6.48	8.28	8.12	7.88
Other Renewable Energy[3]	0.88	1.39	1.51	1.51	1.77	2.00	2.10	2.11	2.45	2.45
Other[4]	0.50	0.53	0.54	0.55	0.60	0.58	0.57	0.65	0.64	0.63
Total	**71.41**	**76.16**	**76.17**	**75.99**	**80.21**	**82.21**	**83.66**	**81.87**	**86.56**	**93.27**
Imports										
Crude Oil	22.08	21.40	21.14	20.42	22.41	21.58	19.62	26.43	24.41	18.93
Liquid Fuels and Other Petroleum[5]	7.21	5.48	5.61	6.27	6.72	5.43	4.94	7.46	5.44	4.71
Natural Gas	4.29	5.00	4.80	4.63	6.40	4.68	3.52	6.98	4.64	3.17
Other Imports[6]	0.98	0.95	0.95	0.96	1.89	1.93	2.00	2.60	2.74	2.92
Total	**34.57**	**32.83**	**32.49**	**32.27**	**37.43**	**33.62**	**30.08**	**43.47**	**37.22**	**29.73**
Exports										
Petroleum[7]	2.60	2.87	2.82	2.88	3.03	2.98	3.08	3.07	3.33	3.25
Natural Gas	0.73	0.85	0.84	0.84	1.12	1.02	0.91	1.60	1.36	1.08
Coal	1.26	1.79	1.79	1.79	0.87	0.87	0.82	0.91	0.88	0.88
Total	**4.59**	**5.50**	**5.45**	**5.51**	**5.02**	**4.87**	**4.82**	**5.58**	**5.56**	**5.21**
Discrepancy[8]	**1.87**	**-0.08**	**-0.13**	**-0.10**	**0.22**	**0.12**	**0.14**	**0.37**	**0.21**	**0.25**
Consumption										
Liquid Fuels and Other Petroleum[9]	40.06	40.61	40.46	40.19	44.30	42.24	40.20	46.89	43.99	41.48
Natural Gas	22.30	24.11	23.93	23.72	25.55	24.01	22.71	25.47	23.39	22.24
Coal[10]	22.50	23.03	23.03	23.03	24.18	25.87	26.81	27.38	29.90	32.11
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.66
Hydropower	2.89	2.92	2.92	2.92	3.00	3.00	3.01	3.01	3.00	3.01
Biomass[11]	2.50	3.02	3.01	2.99	4.53	4.50	4.49	5.63	5.51	5.36
Other Renewable Energy[3]	0.88	1.39	1.51	1.51	1.77	2.00	2.10	2.11	2.45	2.45
Other[12]	0.19	0.18	0.18	0.19	0.17	0.17	0.19	0.18	0.20	0.22
Total	**99.52**	**103.57**	**103.34**	**102.87**	**112.39**	**110.85**	**108.78**	**119.39**	**118.01**	**117.54**

Table C1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Prices (2006 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price	66.02	71.45	74.03	79.02	39.07	59.70	102.07	42.35	70.45	118.65
Imported Crude Oil Price[13]	59.05	62.64	65.18	69.19	33.46	51.55	88.31	34.61	58.66	96.42
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.73	6.61	6.90	7.28	5.01	5.95	7.08	6.00	7.22	8.43
Wellhead Price[14]	6.24	5.89	6.16	6.50	4.43	5.29	6.32	5.33	6.45	7.55
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.42	6.06	6.33	6.69	4.56	5.44	6.50	5.49	6.63	7.77
Coal (dollars per ton)										
Minemouth Price[15]	24.63	25.88	26.16	26.17	21.68	22.51	23.62	22.06	23.32	24.79
Coal (dollars per million Btu)										
Minemouth Price[15]	1.21	1.27	1.28	1.28	1.09	1.14	1.20	1.12	1.19	1.28
Average Delivered Price[15]	1.78	1.92	1.93	1.94	1.69	1.77	1.86	1.72	1.82	1.92
Average Electricity Price (cents per kilowatthour)	8.9	9.1	9.2	9.3	8.3	8.6	8.9	8.5	8.8	9.1

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.47	0.48	0.48	0.48	0.52	0.52	0.51	0.56	0.55	0.55
Kerosene	0.07	0.08	0.08	0.08	0.09	0.08	0.08	0.09	0.08	0.07
Distillate Fuel Oil	0.70	0.76	0.75	0.75	0.78	0.73	0.65	0.72	0.65	0.56
Liquid Fuels and Other Petroleum Subtotal	1.25	1.32	1.31	1.31	1.40	1.33	1.24	1.37	1.29	1.18
Natural Gas	4.50	4.97	4.95	4.93	5.41	5.30	5.20	5.44	5.32	5.23
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.41	0.44	0.44	0.44	0.39	0.40	0.42	0.36	0.38	0.40
Electricity	4.61	4.95	4.95	4.94	5.29	5.25	5.22	5.90	5.88	5.85
Delivered Energy	**10.77**	**11.69**	**11.66**	**11.63**	**12.49**	**12.30**	**12.09**	**13.08**	**12.88**	**12.66**
Electricity Related Losses	10.04	10.58	10.59	10.58	10.98	11.08	11.12	11.91	12.14	12.10
Total	**20.82**	**22.27**	**22.25**	**22.21**	**23.47**	**23.39**	**23.21**	**24.99**	**25.01**	**24.76**
Commercial										
Liquefied Petroleum Gases	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.42	0.38	0.38	0.38	0.45	0.41	0.37	0.49	0.41	0.38
Residual Fuel Oil	0.11	0.10	0.10	0.09	0.11	0.10	0.10	0.11	0.10	0.10
Liquid Fuels and Other Petroleum Subtotal	0.68	0.64	0.63	0.63	0.73	0.68	0.63	0.76	0.68	0.64
Natural Gas	2.92	3.06	3.04	3.03	3.56	3.47	3.37	3.87	3.78	3.67
Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Renewable Energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.43	4.74	4.73	4.72	5.72	5.67	5.62	6.68	6.62	6.57
Delivered Energy	**8.25**	**8.64**	**8.62**	**8.59**	**10.22**	**10.03**	**9.83**	**11.52**	**11.30**	**11.09**
Electricity Related Losses	9.66	10.12	10.12	10.12	11.87	11.96	11.99	13.47	13.68	13.59
Total	**17.91**	**18.76**	**18.74**	**18.70**	**22.08**	**21.98**	**21.82**	**24.99**	**24.98**	**24.68**
Industrial[4]										
Liquefied Petroleum Gases	2.09	2.13	2.12	2.12	1.87	1.83	1.78	1.75	1.71	1.71
Motor Gasoline[2]	0.38	0.38	0.38	0.37	0.37	0.37	0.37	0.38	0.38	0.37
Distillate Fuel Oil	1.28	1.29	1.29	1.28	1.26	1.23	1.22	1.29	1.23	1.23
Residual Fuel Oil	0.28	0.28	0.28	0.28	0.30	0.23	0.19	0.37	0.23	0.19
Petrochemical Feedstocks	1.41	1.37	1.36	1.36	1.41	1.39	1.36	1.30	1.29	1.30
Other Petroleum[5]	4.48	4.31	4.25	4.14	4.67	4.22	3.73	4.93	4.41	3.62
Liquid Fuels and Other Petroleum Subtotal	9.92	9.76	9.67	9.57	9.89	9.27	8.65	10.02	9.25	8.42
Natural Gas	6.68	7.15	7.16	7.12	7.00	7.14	7.21	6.73	7.08	7.21
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.20
Lease and Plant Fuel[6]	1.17	1.21	1.21	1.21	1.25	1.25	1.26	1.27	1.27	1.30
Natural Gas Subtotal	7.85	8.36	8.37	8.33	8.25	8.39	8.68	8.00	8.35	8.71
Metallurgical Coal	0.60	0.60	0.60	0.59	0.56	0.54	0.51	0.50	0.48	0.47
Other Industrial Coal	1.26	1.31	1.31	1.30	1.19	1.20	1.19	1.16	1.18	1.18
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.09	0.34	0.45	0.09	0.55	2.69
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Coal Subtotal	1.92	1.94	1.93	1.92	1.87	2.11	2.19	1.80	2.26	4.39
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.66	1.51	1.49	1.49	2.41	2.31	2.09
Renewable Energy[7]	1.69	1.67	1.66	1.66	1.86	1.83	1.80	2.04	2.02	2.00
Electricity	3.42	3.52	3.50	3.48	3.65	3.59	3.52	3.51	3.52	3.58
Delivered Energy	**25.10**	**25.93**	**25.82**	**25.62**	**27.04**	**26.70**	**26.32**	**27.77**	**27.70**	**29.19**
Electricity Related Losses	7.45	7.52	7.50	7.45	7.57	7.57	7.51	7.07	7.28	7.40
Total	**32.55**	**33.45**	**33.32**	**33.07**	**34.61**	**34.27**	**33.83**	**34.84**	**34.98**	**36.59**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Transportation										
Liquefied Petroleum Gases	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.01	0.01	0.02
E85[8]	0.00	0.00	0.00	0.00	0.95	0.97	0.91	1.17	1.34	1.65
Motor Gasoline[2]	17.20	17.28	17.25	17.14	17.46	16.56	15.36	17.54	15.97	13.83
Jet Fuel[9]	3.16	3.45	3.44	3.43	4.16	4.15	4.14	4.79	4.79	4.79
Distillate Fuel Oil[10]	6.18	6.56	6.54	6.52	7.75	7.63	7.64	9.09	8.98	9.29
Residual Fuel Oil	0.83	0.85	0.85	0.85	0.86	0.86	0.86	0.87	0.87	0.87
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[11]	0.18	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.18
Liquid Fuels and Other Petroleum Subtotal	27.57	28.34	28.29	28.14	31.36	30.37	29.11	33.65	32.15	30.62
Pipeline Fuel Natural Gas	0.59	0.64	0.64	0.64	0.71	0.69	0.66	0.76	0.72	0.70
Compressed Natural Gas	0.02	0.04	0.04	0.04	0.07	0.07	0.07	0.08	0.08	0.09
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Delivered Energy	**28.20**	**29.04**	**28.98**	**28.84**	**32.17**	**31.15**	**29.87**	**34.51**	**32.98**	**31.44**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Total	**28.25**	**29.09**	**29.03**	**28.89**	**32.23**	**31.21**	**29.92**	**34.57**	**33.04**	**31.50**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.65	2.72	2.70	2.71	2.50	2.45	2.40	2.41	2.37	2.37
E85[8]	0.00	0.00	0.00	0.00	0.95	0.97	0.91	1.17	1.34	1.65
Motor Gasoline[2]	17.62	17.71	17.68	17.56	17.88	16.99	15.78	17.97	16.40	14.25
Jet Fuel[9]	3.16	3.45	3.44	3.43	4.16	4.15	4.14	4.79	4.79	4.79
Kerosene	0.11	0.12	0.12	0.12	0.13	0.13	0.12	0.13	0.13	0.11
Distillate Fuel Oil	8.59	8.99	8.97	8.93	10.25	10.00	9.89	11.59	11.28	11.46
Residual Fuel Oil	1.23	1.23	1.23	1.23	1.27	1.19	1.15	1.35	1.20	1.16
Petrochemical Feedstocks	1.41	1.37	1.36	1.36	1.41	1.39	1.36	1.30	1.29	1.30
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.64	4.47	4.40	4.29	4.83	4.38	3.88	5.09	4.56	3.77
Liquid Fuels and Other Petroleum Subtotal	39.41	40.06	39.90	39.64	43.38	41.65	39.63	45.80	43.37	40.87
Natural Gas	14.12	15.21	15.19	15.11	16.04	15.98	15.85	16.11	16.27	16.19
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.20
Lease and Plant Fuel[6]	1.17	1.21	1.21	1.21	1.25	1.25	1.26	1.27	1.27	1.30
Pipeline Natural Gas	0.59	0.64	0.64	0.64	0.71	0.69	0.66	0.76	0.72	0.70
Natural Gas Subtotal	15.88	17.06	17.04	16.96	18.00	17.93	17.97	18.14	18.26	18.39
Metallurgical Coal	0.60	0.60	0.60	0.59	0.56	0.54	0.51	0.50	0.48	0.47
Other Coal	1.35	1.40	1.40	1.40	1.28	1.29	1.28	1.25	1.27	1.27
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.09	0.34	0.45	0.09	0.55	2.69
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Coal Subtotal	2.02	2.03	2.03	2.02	1.96	2.21	2.28	1.89	2.35	4.48
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.66	1.51	1.49	1.49	2.41	2.31	2.09
Renewable Energy[13]	2.23	2.24	2.23	2.23	2.38	2.37	2.35	2.53	2.52	2.53
Electricity	12.49	13.23	13.20	13.16	14.68	14.54	14.38	16.12	16.05	16.03
Delivered Energy	**72.32**	**75.30**	**75.08**	**74.67**	**81.92**	**80.18**	**78.10**	**86.88**	**84.86**	**84.38**
Electricity Related Losses	27.19	28.27	28.26	28.20	30.47	30.67	30.68	32.51	33.16	33.15
Total	**99.52**	**103.57**	**103.34**	**102.87**	**112.39**	**110.85**	**108.78**	**119.39**	**118.01**	**117.54**
Electric Power[14]										
Distillate Fuel Oil	0.18	0.18	0.18	0.18	0.20	0.20	0.20	0.22	0.23	0.22
Residual Fuel Oil	0.46	0.38	0.38	0.38	0.72	0.39	0.37	0.87	0.40	0.39
Liquid Fuels and Other Petroleum Subtotal	0.64	0.56	0.56	0.56	0.92	0.59	0.57	1.09	0.63	0.61
Natural Gas	6.42	7.05	6.89	6.76	7.55	6.09	4.74	7.34	5.13	3.85
Steam Coal	20.48	21.00	21.01	21.01	22.21	23.67	24.54	25.50	27.55	27.63
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.66
Renewable Energy[15]	3.74	4.41	4.53	4.53	5.40	5.64	5.76	5.80	6.13	6.21
Electricity Imports	0.06	0.05	0.05	0.06	0.04	0.04	0.07	0.05	0.08	0.09
Total[16]	**39.68**	**41.50**	**41.46**	**41.36**	**45.16**	**45.21**	**45.06**	**48.63**	**49.21**	**49.18**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Total Energy Consumption										
Liquefied Petroleum Gases	2.65	2.72	2.70	2.71	2.50	2.45	2.40	2.41	2.37	2.37
E85[8]	0.00	0.00	0.00	0.00	0.95	0.97	0.91	1.17	1.34	1.65
Motor Gasoline[2]	17.62	17.71	17.68	17.56	17.88	16.99	15.78	17.97	16.40	14.25
Jet Fuel[9]	3.16	3.45	3.44	3.43	4.16	4.15	4.14	4.79	4.79	4.79
Kerosene	0.11	0.12	0.12	0.12	0.13	0.13	0.12	0.13	0.13	0.11
Distillate Fuel Oil	8.77	9.17	9.15	9.11	10.45	10.20	10.09	11.81	11.51	11.68
Residual Fuel Oil	1.69	1.61	1.60	1.61	1.99	1.58	1.52	2.22	1.60	1.55
Petrochemical Feedstocks	1.41	1.37	1.36	1.36	1.41	1.39	1.36	1.30	1.29	1.30
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.64	4.47	4.40	4.29	4.83	4.38	3.88	5.09	4.56	3.77
Liquid Fuels and Other Petroleum Subtotal	40.06	40.61	40.46	40.19	44.30	42.24	40.20	46.89	43.99	41.48
Natural Gas	20.54	22.26	22.08	21.88	23.59	22.07	20.58	23.45	21.40	20.04
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.20
Lease and Plant Fuel[6]	1.17	1.21	1.21	1.21	1.25	1.25	1.26	1.27	1.27	1.30
Pipeline Natural Gas	0.59	0.64	0.64	0.64	0.71	0.69	0.66	0.76	0.72	0.70
Natural Gas Subtotal	22.30	24.11	23.93	23.72	25.55	24.01	22.71	25.47	23.39	22.24
Metallurgical Coal	0.60	0.60	0.60	0.59	0.56	0.54	0.51	0.50	0.48	0.47
Other Coal	21.83	22.40	22.41	22.41	23.49	24.96	25.82	26.75	28.82	28.90
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.09	0.34	0.45	0.09	0.55	2.69
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Coal Subtotal	22.50	23.03	23.03	23.03	24.18	25.87	26.81	27.38	29.90	32.11
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.66
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.66	1.51	1.49	1.49	2.41	2.31	2.09
Renewable Energy[17]	5.97	6.65	6.76	6.76	7.79	8.01	8.11	8.34	8.66	8.74
Electricity Imports	0.06	0.05	0.05	0.06	0.04	0.04	0.07	0.05	0.08	0.09
Total	**99.52**	**103.57**	**103.34**	**102.87**	**112.39**	**110.85**	**108.78**	**119.39**	**118.01**	**117.54**
Energy Use and Related Statistics										
Delivered Energy Use	72.32	75.30	75.08	74.67	81.92	80.18	78.10	86.88	84.86	84.38
Total Energy Use	99.52	103.57	103.34	102.87	112.39	110.85	108.78	119.39	118.01	117.54
Ethanol Consumed in Motor Gasoline and E85	0.47	1.05	1.05	1.03	1.82	1.82	1.68	1.97	2.01	2.07
Population (millions)	300.13	310.85	310.85	310.85	337.74	337.74	337.74	365.59	365.59	365.59
Gross Domestic Product (billion 2000 dollars)	11319	12465	12453	12426	16030	15984	15944	20228	20219	20258
Carbon Dioxide Emissions (million metric tons)	5890.3	6030.9	6010.6	5983.0	6450.0	6384.1	6258.9	6941.2	6851.0	6799.2

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2006 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 population and gross domestic product. Global Insight, Global Insight Industry and Employment models, July 2007. 2006 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C3. Energy Prices by Sector and Source
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Residential										
Liquefied Petroleum Gases	23.08	24.91	25.21	25.59	23.30	24.23	25.36	24.26	25.43	26.63
Distillate Fuel Oil	17.94	16.45	17.21	18.25	10.60	14.27	22.09	11.54	16.27	24.45
Natural Gas	13.40	11.85	12.15	12.55	10.43	11.39	12.57	11.71	12.91	14.10
Electricity	30.52	31.02	31.37	31.79	29.21	30.20	31.09	29.82	30.63	31.48
Commercial										
Distillate Fuel Oil	14.59	14.51	15.24	16.12	9.51	13.24	20.37	10.27	15.00	23.16
Residual Fuel Oil	8.60	9.64	10.06	10.69	5.03	7.95	13.09	5.50	9.22	15.41
Natural Gas	11.50	10.30	10.59	10.98	8.97	9.91	11.04	10.26	11.43	12.61
Electricity	27.75	27.52	27.89	28.35	24.45	25.64	26.90	25.01	26.17	27.33
Industrial[1]										
Liquefied Petroleum Gases	19.71	17.49	17.74	18.12	15.94	16.79	17.75	16.77	17.79	19.02
Distillate Fuel Oil	15.33	15.02	15.72	16.46	10.85	14.62	21.23	11.56	16.26	24.32
Residual Fuel Oil	9.06	10.10	10.86	11.00	5.48	8.29	12.92	6.20	9.62	15.20
Natural Gas[2]	7.66	6.94	7.21	7.58	5.35	6.21	7.29	6.22	7.29	8.44
Metallurgical Coal	3.54	4.06	4.07	4.08	3.39	3.42	3.48	3.56	3.60	3.67
Other Industrial Coal	2.34	2.41	2.42	2.43	2.20	2.28	2.38	2.23	2.33	2.48
Coal to Liquids	--	--	--	--	0.86	1.09	1.26	0.95	1.30	1.57
Electricity	17.97	18.90	19.21	19.60	16.47	17.27	17.89	16.98	17.63	18.11
Transportation										
Liquefied Petroleum Gases[3]	21.72	25.74	26.03	26.35	24.02	24.94	26.04	24.87	26.03	27.21
E85[4]	24.81	21.86	23.58	26.14	15.25	18.15	27.14	15.22	19.62	28.81
Motor Gasoline[5]	21.19	20.43	21.23	23.66	15.35	19.64	27.35	15.35	20.37	29.37
Jet Fuel[6]	14.83	15.13	15.77	17.13	9.18	13.27	21.13	10.22	15.37	23.87
Distillate Fuel Oil[7]	19.72	19.00	19.68	20.45	14.47	18.26	24.74	14.87	19.59	27.72
Residual Fuel Oil	7.89	9.93	10.53	10.83	5.68	8.69	14.02	6.50	10.39	16.44
Natural Gas[8]	14.28	13.33	13.60	13.99	11.22	12.15	13.37	11.64	12.83	14.12
Electricity	29.73	30.48	30.95	31.53	27.77	29.05	30.29	28.56	29.65	30.43
Electric Power[9]										
Distillate Fuel Oil	13.35	12.88	13.62	14.64	7.07	10.69	18.33	8.02	12.71	20.66
Residual Fuel Oil	8.17	8.87	9.45	9.79	4.43	7.50	12.73	5.09	9.04	15.14
Natural Gas	6.87	6.71	6.96	7.31	5.11	5.95	6.96	5.90	6.93	8.06
Steam Coal	1.69	1.83	1.84	1.85	1.62	1.72	1.82	1.66	1.78	1.93
Average Price to All Users[10]										
Liquefied Petroleum Gases	20.35	19.01	19.27	19.65	17.70	18.59	19.63	18.72	19.82	21.03
E85[4]	24.81	21.86	23.58	26.14	15.25	18.15	27.14	15.22	19.62	28.81
Motor Gasoline[5]	21.06	20.43	21.23	23.66	15.35	19.64	27.35	15.35	20.37	29.37
Jet Fuel	14.83	15.13	15.77	17.13	9.18	13.27	21.13	10.22	15.37	23.87
Distillate Fuel Oil	18.56	17.78	18.48	19.25	13.39	17.20	23.84	13.99	18.74	26.92
Residual Fuel Oil	8.21	9.69	10.31	10.61	5.16	8.29	13.50	5.84	9.87	15.90
Natural Gas	9.22	8.43	8.72	9.10	7.00	7.98	9.18	8.07	9.36	10.63
Metallurgical Coal	3.54	4.06	4.07	4.08	3.39	3.42	3.48	3.56	3.60	3.67
Other Coal	1.73	1.86	1.88	1.89	1.66	1.75	1.85	1.69	1.81	1.95
Coal to Liquids	--	--	--	--	0.86	1.09	1.26	0.95	1.30	1.57
Electricity	26.10	26.54	26.90	27.34	24.19	25.23	26.22	25.03	25.93	26.79

Table C3. Energy Prices by Sector and Source (Continued)
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Non-Renewable Energy Expenditures by Sector (billion 2006 dollars)										
Residential	225.38	238.17	241.71	246.28	232.30	243.22	256.49	262.54	274.70	287.88
Commercial	166.54	171.75	174.38	177.84	179.61	189.37	201.22	215.50	227.37	240.45
Industrial	205.11	218.32	224.65	230.83	171.15	193.16	221.31	177.82	203.93	235.22
Transportation	542.63	540.60	560.74	608.98	426.17	530.80	712.89	462.11	587.86	797.19
Total Non-Renewable Expenditures	1139.66	1168.84	1201.48	1263.94	1009.23	1156.54	1391.91	1117.96	1293.86	1560.74
Transportation Renewable Expenditures	0.03	0.07	0.06	0.07	14.43	17.64	24.80	17.78	26.35	47.45
Total Expenditures	**1139.70**	**1168.91**	**1201.54**	**1264.00**	**1023.66**	**1174.18**	**1416.71**	**1135.74**	**1320.22**	**1608.20**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2006 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 transportation sector natural gas delivered prices are model results. 2006 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2006 through April 2007. 2006 coal prices based on: EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007) and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. 2006 electricity prices: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C4. Liquid Fuels Supply and Disposition
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Crude Oil										
Domestic Crude Production[1]	5.10	5.97	5.93	5.87	6.35	6.23	6.31	5.18	5.59	6.37
Alaska	0.74	0.69	0.69	0.68	0.77	0.70	0.65	0.32	0.30	0.41
Lower 48 States	4.36	5.29	5.24	5.19	5.59	5.53	5.66	4.86	5.30	5.96
Net Imports	10.09	9.72	9.60	9.27	10.12	9.75	8.87	11.93	11.03	8.54
Gross Imports	10.12	9.75	9.63	9.30	10.15	9.79	8.90	11.95	11.06	8.57
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Crude Supply[2]	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.24**	**15.69**	**15.53**	**15.15**	**16.47**	**15.98**	**15.17**	**17.11**	**16.63**	**14.91**
Other Supply										
Natural Gas Plant Liquids	1.74	1.69	1.68	1.68	1.72	1.72	1.69	1.56	1.57	1.56
Net Product Imports	2.31	1.63	1.72	2.07	2.00	1.37	1.15	2.41	1.26	0.88
Gross Refined Product Imports[3]	2.17	1.48	1.61	1.72	1.74	1.41	1.22	2.11	1.56	1.16
Unfinished Oil Imports	0.69	0.70	0.67	0.58	0.79	0.64	0.57	0.87	0.70	0.54
Blending Component Imports	0.68	0.77	0.74	1.09	0.85	0.67	0.78	0.81	0.52	0.68
Exports	1.22	1.31	1.30	1.32	1.38	1.36	1.41	1.38	1.52	1.50
Refinery Processing Gain[4]	0.99	1.06	1.05	0.96	0.99	1.00	0.86	0.99	0.99	0.68
Other Inputs	0.45	1.03	1.04	1.02	1.87	1.97	2.11	2.20	2.41	3.53
Ethanol	0.36	0.81	0.81	0.80	1.41	1.41	1.30	1.53	1.56	1.61
Domestic Production	0.32	0.76	0.74	0.73	1.19	1.17	1.10	1.44	1.44	1.35
Net Imports	0.05	0.06	0.07	0.06	0.22	0.24	0.20	0.09	0.12	0.26
Biodiesel	0.02	0.04	0.04	0.04	0.07	0.07	0.08	0.07	0.08	0.10
Domestic Production	0.02	0.04	0.04	0.04	0.07	0.07	0.08	0.07	0.08	0.10
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00	0.13
Liquids from Coal	0.00	0.00	0.00	0.00	0.04	0.15	0.20	0.04	0.24	1.18
Liquids from Biomass	0.00	0.00	0.00	0.00	0.14	0.14	0.20	0.33	0.29	0.28
Other[5]	0.07	0.18	0.18	0.19	0.21	0.21	0.20	0.24	0.24	0.23
Total Primary Supply[6]	**20.74**	**21.10**	**21.02**	**20.87**	**23.06**	**22.04**	**20.99**	**24.26**	**22.86**	**21.57**
Liquid Fuels Consumption										
by Fuel										
Liquefied Petroleum Gases	2.05	2.06	2.05	2.06	1.90	1.86	1.82	1.83	1.80	1.80
E85[7]	0.00	0.00	0.00	0.00	0.65	0.67	0.63	0.80	0.92	1.13
Motor Gasoline[8]	9.25	9.60	9.59	9.54	9.73	9.24	8.60	9.77	8.91	7.75
Jet Fuel[9]	1.63	1.67	1.66	1.66	2.01	2.01	2.00	2.31	2.31	2.31
Distillate Fuel Oil[10]	4.17	4.41	4.40	4.38	5.03	4.91	4.85	5.68	5.53	5.61
Diesel	3.21	3.73	3.72	3.71	4.31	4.23	4.22	4.96	4.87	5.01
Residual Fuel Oil	0.69	0.70	0.70	0.70	0.87	0.69	0.66	0.97	0.70	0.67
Other[11]	2.86	2.61	2.58	2.53	2.80	2.58	2.35	2.85	2.62	2.28
by Sector										
Residential and Commercial	1.07	1.09	1.08	1.08	1.18	1.13	1.06	1.20	1.12	1.05
Industrial[12]	5.15	5.10	5.06	5.01	5.08	4.79	4.50	5.09	4.73	4.37
Transportation	14.05	14.63	14.60	14.54	16.31	15.79	15.11	17.46	16.66	15.87
Electric Power[13]	0.29	0.25	0.25	0.25	0.41	0.26	0.26	0.48	0.28	0.27
Total	**20.65**	**21.06**	**20.99**	**20.87**	**22.99**	**21.96**	**20.92**	**24.22**	**22.80**	**21.57**
Discrepancy[14]	**0.09**	**0.04**	**0.03**	**-0.00**	**0.07**	**0.08**	**0.08**	**0.04**	**0.06**	**0.00**

Table C4. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Domestic Refinery Distillation Capacity[15]	17.3	18.3	18.3	18.3	18.3	18.3	18.3	18.6	18.4	18.3
Capacity Utilization Rate (percent)[16]	90.0	87.6	86.8	84.6	92.0	89.3	84.7	93.8	92.0	83.2
Net Import Share of Product Supplied (percent)	60.0	54.1	54.2	54.6	53.5	51.6	48.7	59.5	54.3	44.9
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2006 dollars)	264.86	243.47	254.07	266.30	148.06	207.19	311.47	178.98	261.91	324.14

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, and ethers.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[11]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, liquid hydrogen,and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 data: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C5. Petroleum Product Prices
(2006 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Crude Oil Prices (2006 dollars per barrel)										
Imported Low Sulfur Light Crude Oil	66.02	71.45	74.03	79.02	39.07	59.70	102.07	42.35	70.45	118.65
Imported Crude Oil[1]	59.05	62.64	65.18	69.19	33.46	51.55	88.31	34.61	58.66	96.42
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	198.1	213.8	216.3	219.6	200.0	207.9	217.7	208.2	218.3	228.6
Distillate Fuel Oil	248.8	228.1	238.6	253.1	147.0	198.0	306.3	160.1	225.7	339.0
Commercial										
Distillate Fuel Oil	201.8	200.2	210.2	222.4	131.1	182.5	280.9	141.5	206.7	319.3
Residual Fuel Oil	128.8	144.3	150.7	160.0	75.3	118.9	196.0	82.3	138.0	230.6
Residual Fuel Oil (2006 dollars per barrel)	54.09	60.60	63.27	67.19	31.64	49.95	82.32	34.55	57.97	96.87
Industrial[2]										
Liquefied Petroleum Gases	169.2	150.1	152.3	155.5	136.8	144.1	152.4	144.0	152.7	163.2
Distillate Fuel Oil	212.1	206.6	216.2	226.4	149.0	200.7	291.4	158.7	223.1	333.9
Residual Fuel Oil	135.6	151.1	162.6	164.7	82.1	124.0	193.3	92.7	144.0	227.6
Residual Fuel Oil (2006 dollars per barrel)	56.96	63.48	68.29	69.16	34.47	52.10	81.20	38.95	60.48	95.58
Transportation										
Liquefied Petroleum Gases	186.4	220.9	223.4	226.1	206.2	214.0	223.5	213.4	223.4	233.5
Ethanol (E85)[3]	235.4	207.4	223.7	248.0	144.6	172.2	257.5	144.4	186.1	273.4
Ethanol Wholesale Price	250.0	179.5	180.8	203.5	196.5	200.7	194.1	145.9	152.2	179.6
Motor Gasoline[4]	263.3	245.8	255.4	284.1	184.1	235.5	327.5	184.2	244.6	352.3
Jet Fuel[5]	200.2	204.3	212.8	231.2	123.9	179.2	285.2	137.9	207.5	322.3
Diesel Fuel (distillate fuel oil)[6]	271.0	260.5	269.8	280.3	198.3	250.2	339.0	203.8	268.5	379.9
Residual Fuel Oil	118.1	148.6	157.7	162.1	85.1	130.1	209.9	97.3	155.5	246.1
Residual Fuel Oil (2006 dollars per barrel)	49.62	62.41	66.22	68.09	35.73	54.64	88.14	40.86	65.32	103.38
Electric Power[7]										
Distillate Fuel Oil	185.1	178.6	189.0	203.1	98.1	148.3	254.3	111.2	176.2	286.5
Residual Fuel Oil	122.3	132.8	141.5	146.6	66.4	112.3	190.5	76.1	135.3	226.6
Residual Fuel Oil (2006 dollars per barrel)	51.37	55.80	59.43	61.56	27.87	47.18	80.02	31.98	56.84	95.17
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	174.6	163.2	165.4	168.7	151.9	159.5	168.5	160.7	170.1	180.5
Motor Gasoline[4]	261.6	245.7	255.4	284.1	184.0	235.5	327.5	184.2	244.6	352.2
Jet Fuel[5]	200.2	204.3	212.8	231.2	123.9	179.2	285.2	137.9	207.5	322.3
Distillate Fuel Oil	255.9	244.4	253.9	264.5	183.8	236.1	327.2	191.9	257.1	369.4
Residual Fuel Oil	122.9	145.1	154.3	158.8	77.3	124.1	202.1	87.5	147.7	238.0
Residual Fuel Oil (2006 dollars per barrel)	51.63	60.93	64.80	66.69	32.47	52.12	84.89	36.74	62.04	99.95
Average	**234.5**	**224.3**	**233.1**	**252.3**	**166.4**	**214.1**	**296.3**	**171.4**	**229.6**	**326.4**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2006 imported crude oil price: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2006 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2006 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2006 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2006 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C6. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Crude Oil Prices (2006 dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price	66.02	71.45	74.03	79.02	39.07	59.70	102.07	42.35	70.45	118.65
Imported Crude Oil Price[1]	59.05	62.64	65.18	69.19	33.46	51.55	88.31	34.61	58.66	96.42
Conventional Production (Conventional)[2]										
OPEC[3]										
Asia	1.11	1.04	1.03	1.03	1.03	0.98	0.82	1.14	0.94	0.67
Middle East	23.21	25.67	22.41	20.69	30.59	24.09	21.58	38.17	27.35	22.18
North Africa	3.90	4.28	4.28	4.24	4.98	4.78	3.99	5.80	4.82	3.40
West Africa	4.02	5.78	5.77	5.73	7.71	7.41	6.19	9.89	8.23	5.79
South America	2.06	1.99	1.99	1.97	2.27	2.18	1.82	2.60	2.16	1.52
Total OPEC	**34.30**	**38.76**	**35.48**	**33.67**	**46.58**	**39.45**	**34.40**	**57.59**	**43.50**	**33.55**
Non-OPEC										
OECD										
United States (50 states)	7.91	8.89	8.84	8.70	9.28	9.15	9.06	7.96	8.39	8.70
Canada	2.00	1.86	1.85	1.84	1.66	1.32	1.05	1.32	1.05	0.76
Mexico	3.74	3.39	3.37	3.34	4.12	3.25	2.59	4.21	3.35	2.44
OECD Europe[4]	5.52	4.93	4.89	4.85	4.51	3.59	2.86	4.25	3.39	2.47
Japan	0.13	0.12	0.12	0.12	0.16	0.14	0.11	0.19	0.15	0.11
Australia and New Zealand	0.57	0.62	0.62	0.61	0.83	0.65	0.52	0.83	0.66	0.48
Total OECD	**19.85**	**19.81**	**19.69**	**19.46**	**20.57**	**18.10**	**16.19**	**18.76**	**16.99**	**14.96**
Non-OECD										
Russia	9.82	10.40	10.34	10.27	13.82	10.90	8.69	14.71	11.69	8.50
Other Eurasia[5]	2.85	3.80	3.77	3.75	6.92	5.46	4.35	8.01	6.36	4.63
China	3.80	3.86	3.83	3.80	4.90	3.87	3.09	4.43	3.53	2.57
Other Asia[6]	2.89	2.94	2.92	2.90	4.30	3.40	2.71	3.99	3.17	2.31
Middle East[7]	1.69	1.61	2.00	1.59	2.36	2.40	1.48	2.45	2.90	1.42
Africa	2.49	2.93	2.92	2.90	4.86	3.83	3.06	5.03	3.99	2.91
Brazil	1.84	2.42	2.40	2.39	4.30	3.39	2.71	4.61	3.66	2.67
Other Central and South America	2.36	2.33	2.32	2.30	3.39	2.67	2.13	4.41	3.51	2.55
Total Non-OECD	**27.73**	**30.28**	**30.51**	**29.89**	**44.83**	**35.94**	**28.23**	**47.64**	**38.81**	**27.55**
Total Conventional Production	**81.88**	**88.85**	**85.67**	**83.02**	**111.98**	**93.48**	**78.82**	**123.99**	**99.30**	**76.07**
Unconventional Production[8]										
United States (50 states)	0.34	0.80	0.78	0.78	1.44	1.53	1.71	1.87	2.06	3.19
Other North America	1.23	1.89	1.91	1.92	1.71	2.85	3.48	2.10	3.96	4.88
OECD Europe[3]	0.04	0.07	0.07	0.07	0.09	0.15	0.27	0.14	0.26	0.51
Middle East[7]	0.00	0.03	0.03	0.03	0.18	0.31	0.36	0.66	1.24	1.45
Africa	0.17	0.31	0.31	0.31	0.27	0.44	0.79	0.44	0.83	1.51
Central and South America	0.80	1.17	1.18	1.19	1.05	1.76	2.46	1.33	2.51	3.64
Other	0.20	0.43	0.44	0.44	0.76	1.28	2.46	1.66	3.15	6.47
Total Unconventional Production	**2.78**	**4.70**	**4.73**	**4.75**	**5.49**	**8.32**	**11.52**	**8.19**	**14.00**	**21.65**
Total Production	**84.66**	**93.55**	**90.40**	**87.76**	**117.47**	**101.80**	**90.34**	**132.18**	**113.31**	**97.71**

Table C6. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Consumption[6]										
OECD										
United States (50 states)	20.65	21.06	20.99	20.87	22.51	21.47	20.45	23.62	22.11	20.73
United States Territories	0.38	0.46	0.43	0.39	0.62	0.51	0.48	0.70	0.59	0.54
Canada	2.27	2.43	2.32	2.23	2.82	2.36	2.04	2.87	2.40	2.01
Mexico	2.06	2.29	2.19	2.10	3.09	2.61	2.24	3.53	2.95	2.48
OECD Europe[3]	15.42	16.22	15.47	14.85	18.69	15.71	13.59	18.99	15.86	13.27
Japan	5.16	5.41	5.18	4.98	6.18	5.22	4.54	6.26	5.26	4.44
South Korea	2.18	2.36	2.25	2.16	3.07	2.57	2.23	3.37	2.81	2.36
Australia and New Zealand	1.03	1.12	1.07	1.03	1.41	1.19	1.03	1.54	1.28	1.08
Total OECD	**49.16**	**51.36**	**49.90**	**48.61**	**58.38**	**51.64**	**46.60**	**60.88**	**53.28**	**46.89**
Non-OECD										
Russia	2.79	3.00	2.89	2.80	3.65	3.13	2.77	3.90	3.32	2.84
Other Non-OECD Eurasia[5]	2.09	2.37	2.26	2.17	3.11	2.64	2.29	3.50	2.96	2.50
China	7.26	9.86	9.44	9.08	14.21	11.96	10.39	18.73	15.69	13.20
India	2.49	2.81	2.68	2.57	4.30	3.62	3.14	5.23	4.37	3.67
Other Non-OECD Asia	6.14	6.97	6.67	6.40	9.86	8.35	7.20	11.74	9.86	8.29
Middle East[7]	6.15	7.30	7.13	7.05	9.65	8.46	7.61	11.36	9.84	8.61
Africa	2.99	3.53	3.36	3.20	5.20	4.35	3.71	5.94	4.93	4.09
Brazil	2.34	2.69	2.57	2.47	3.75	3.15	2.72	4.42	3.68	3.08
Other Central and South America	3.26	3.68	3.51	3.41	5.37	4.51	3.90	6.48	5.37	4.53
Total Non-OECD	**35.51**	**42.20**	**40.51**	**39.16**	**59.09**	**50.16**	**43.73**	**71.30**	**60.02**	**50.81**
Total Consumption	**84.66**	**93.55**	**90.40**	**87.76**	**117.48**	**101.80**	**90.34**	**132.18**	**113.30**	**97.70**
OPEC Production[10]	34.90	39.67	36.40	34.59	47.42	40.87	36.12	59.00	46.16	36.75
Non-OPEC Production[10]	49.76	53.88	54.00	53.17	70.05	60.94	54.22	73.19	67.15	60.96
Net Eurasia Exports	9.63	11.25	11.37	11.44	18.28	13.98	10.70	19.92	15.43	10.46
OPEC Market Share	41.2	42.4	40.3	39.4	40.4	40.1	40.0	44.6	40.7	37.6

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela. Does not include Ecuador, which was admitted to OPEC as a full member on November 17, 2007.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Eurasia consists of Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2006 imported crude oil price: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **2006 quantities and projections:** Energy Information Administration, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Appendix D

Results from Side Cases

Table D1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2006	2010				2020			
		2008 Technology	Reference	High Technology	Best Available Technology	2008 Technology	Reference	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.47	0.48	0.48	0.48	0.47	0.53	0.52	0.51	0.49
Kerosene	0.07	0.08	0.08	0.08	0.08	0.09	0.08	0.08	0.07
Distillate Fuel Oil	0.70	0.75	0.75	0.75	0.74	0.74	0.73	0.72	0.65
Liquid Fuels and Other Petroleum	1.25	1.32	1.31	1.31	1.28	1.36	1.33	1.31	1.20
Natural Gas	4.50	4.97	4.95	4.93	4.78	5.49	5.30	5.18	4.46
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.41	0.44	0.44	0.44	0.43	0.42	0.40	0.40	0.37
Electricity	4.61	5.00	4.95	4.94	4.40	5.53	5.25	5.08	4.30
Delivered Energy	**10.77**	**11.74**	**11.66**	**11.63**	**10.91**	**12.81**	**12.30**	**11.97**	**10.34**
Electricity Related Losses	10.04	10.70	10.59	10.57	9.42	11.66	11.08	10.72	9.06
Total	**20.82**	**22.45**	**22.25**	**22.20**	**20.33**	**24.47**	**23.39**	**22.69**	**19.41**
Delivered Energy Intensity (million Btu per household)	**95.8**	**101.2**	**100.5**	**100.2**	**94.0**	**99.2**	**95.3**	**92.7**	**80.1**
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.03**	**0.04**	**0.04**	**0.03**
Commercial									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.42	0.38	0.38	0.38	0.38	0.42	0.41	0.41	0.45
Residual Fuel Oil	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Liquid Fuels and Other Petroleum	0.68	0.63	0.63	0.63	0.64	0.68	0.68	0.67	0.71
Natural Gas	2.92	3.05	3.04	3.03	3.00	3.50	3.47	3.41	3.29
Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Renewable Energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.43	4.78	4.73	4.69	4.58	5.95	5.67	5.39	4.90
Delivered Energy	**8.25**	**8.68**	**8.62**	**8.56**	**8.43**	**10.34**	**10.03**	**9.69**	**9.11**
Electricity Related Losses	9.66	10.24	10.12	10.03	9.80	12.56	11.96	11.38	10.34
Total	**17.91**	**18.92**	**18.74**	**18.59**	**18.23**	**22.90**	**21.98**	**21.06**	**19.45**
Delivered Energy Intensity (thousand Btu per square foot)	**110.3**	**110.1**	**109.3**	**108.6**	**107.0**	**115.9**	**112.3**	**108.5**	**102.1**
Commercial Sector Generation									
Net Summer Generation Capacity (megawatts)									
Natural Gas	630	662	665	671	672	908	1106	1325	1452
Solar Photovoltaic	243	505	505	505	506	789	860	902	1013
Wind	18	18	18	19	21	45	71	118	254
Electricity Generation (billion kilowatthours)									
Natural Gas	4.54	4.76	4.79	4.83	4.84	6.53	8.00	9.59	10.52
Solar Photovoltaic	0.38	0.81	0.81	0.81	0.81	1.27	1.41	1.48	1.66
Wind	0.02	0.02	0.02	0.03	0.03	0.06	0.10	0.17	0.36
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, biogenic municipal waste, and other biomass for combined heat and power.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2008 National Energy Modeling System, runs BLDFRZN.D030408A, AEO2008.D030208F, BLDHIGH.D030408A, and BLDBEST.D030408A.

2030				Annual Growth 2006-2030 (percent)			
2008 Technology	Reference	High Technology	Best Available Technology	2008 Technology	Reference	High Technology	Best Available Technology
0.58	0.55	0.54	0.50	0.9%	0.7%	0.6%	0.3%
0.09	0.08	0.08	0.05	0.7%	0.5%	0.1%	-1.4%
0.69	0.65	0.63	0.55	-0.1%	-0.3%	-0.5%	-1.1%
1.35	1.29	1.24	1.10	0.3%	0.1%	-0.0%	-0.5%
5.72	5.32	5.04	3.96	1.0%	0.7%	0.5%	-0.5%
0.01	0.01	0.01	0.01	-0.1%	-0.4%	-0.5%	-0.6%
0.40	0.38	0.36	0.33	-0.1%	-0.3%	-0.5%	-0.9%
6.30	5.88	5.58	4.59	1.3%	1.0%	0.8%	-0.0%
13.78	**12.88**	**12.24**	**9.99**	**1.0%**	**0.7%**	**0.5%**	**-0.3%**
13.01	12.14	11.53	9.49	1.1%	0.8%	0.6%	-0.2%
26.78	**25.01**	**23.77**	**19.48**	**1.1%**	**0.8%**	**0.6%**	**-0.3%**
98.0	**91.6**	**87.0**	**71.1**	**0.1%**	**-0.2%**	**-0.4%**	**-1.2%**
0.05	**0.07**	**0.07**	**0.08**	**4.2%**	**5.9%**	**6.2%**	**6.7%**
0.09	0.09	0.09	0.09	0.6%	0.6%	0.6%	0.6%
0.05	0.05	0.05	0.05	0.4%	0.4%	0.4%	0.4%
0.02	0.02	0.02	0.02	0.2%	0.2%	0.2%	0.2%
0.42	0.41	0.41	0.48	0.0%	-0.0%	-0.1%	0.6%
0.10	0.10	0.10	0.10	-0.4%	-0.4%	-0.4%	-0.4%
0.69	0.68	0.68	0.75	0.1%	0.0%	-0.0%	0.4%
3.81	3.78	3.75	3.62	1.1%	1.1%	1.1%	0.9%
0.08	0.08	0.08	0.08	-0.1%	-0.1%	-0.1%	-0.1%
0.13	0.13	0.13	0.13	0.0%	0.0%	-0.0%	0.0%
7.07	6.62	6.17	5.38	2.0%	1.7%	1.4%	0.8%
11.79	**11.30**	**10.81**	**9.95**	**1.5%**	**1.3%**	**1.1%**	**0.8%**
14.61	13.68	12.73	11.11	1.7%	1.5%	1.2%	0.6%
26.40	**24.98**	**23.55**	**21.06**	**1.6%**	**1.4%**	**1.1%**	**0.7%**
117.0	**112.2**	**107.3**	**98.8**	**0.2%**	**0.1%**	**-0.1%**	**-0.5%**
1462	2621	3631	4720	3.6%	6.1%	7.6%	8.8%
1098	1700	2235	4628	6.5%	8.4%	9.7%	13.1%
168	239	588	2249	9.8%	11.4%	15.7%	22.3%
10.53	19.02	26.37	34.29	3.6%	6.2%	7.6%	8.8%
1.75	2.84	3.73	7.73	6.6%	8.7%	10.0%	13.4%
0.24	0.35	0.84	3.08	10.2%	11.9%	16.0%	22.5%
0.03	**0.04**	**0.04**	**0.07**	**1.1%**	**1.7%**	**2.2%**	**4.0%**

Table D2. Key Results for Industrial Sector Technology Cases, Excluding Refining

Consumption	2006	2010			2020			2030		
		2008 Technology	Reference	High Technology	2008 Technology	Reference	High Technology	2008 Technology	Reference	High Technology
Value of Shipments (billion 2000 dollars)										
Manufacturing	4290	4577	4577	4577	5493	5493	5493	6283	6283	6283
Nonmanufacturing	1531	1419	1419	1419	1619	1619	1619	1715	1715	1715
Total	**5821**	**5997**	**5997**	**5997**	**7113**	**7113**	**7113**	**7997**	**7997**	**7997**
Energy Consumption excluding Refining[1] (quadrillion Btu)										
Liquefied Petroleum Gases	2.08	2.15	2.08	2.02	2.07	1.80	1.59	1.99	1.70	1.48
Heat and Power	0.16	0.17	0.17	0.17	0.18	0.16	0.16	0.18	0.16	0.15
Feedstocks	1.91	1.98	1.92	1.86	1.90	1.64	1.43	1.82	1.55	1.34
Motor Gasoline	0.38	0.38	0.38	0.37	0.40	0.37	0.34	0.42	0.38	0.35
Distillate Fuel Oil	1.28	1.31	1.29	1.27	1.34	1.23	1.14	1.39	1.23	1.11
Residual Fuel Oil	0.27	0.29	0.28	0.27	0.27	0.22	0.21	0.27	0.21	0.20
Petrochemical Feedstocks	1.41	1.38	1.36	1.35	1.45	1.39	1.34	1.37	1.29	1.23
Petroleum Coke	0.36	0.35	0.34	0.34	0.38	0.31	0.29	0.39	0.30	0.27
Asphalt and Road Oil	1.26	1.26	1.22	1.19	1.27	1.08	0.93	1.36	1.13	0.92
Miscellaneous Petroleum[2]	0.56	0.41	0.39	0.38	0.46	0.33	0.31	0.44	0.29	0.26
Petroleum Subtotal	7.60	7.53	7.34	7.20	7.65	6.73	6.14	7.63	6.55	5.82
Natural Gas Heat and Power	5.01	5.30	5.12	5.10	6.05	5.22	5.13	6.16	5.22	5.07
Natural Gas Feedstocks	0.57	0.56	0.54	0.52	0.55	0.46	0.40	0.48	0.39	0.33
Lease and Plant Fuel[3]	1.17	1.21	1.21	1.21	1.25	1.25	1.25	1.27	1.27	1.27
Natural Gas Subtotal	6.74	7.08	6.86	6.83	7.85	6.93	6.78	7.90	6.88	6.66
Metallurgical Coal and Coke[4]	0.66	0.64	0.63	0.61	0.63	0.57	0.49	0.60	0.52	0.42
Other Industrial Coal	1.20	1.26	1.25	1.24	1.23	1.14	1.10	1.23	1.12	1.07
Coal Subtotal	1.86	1.90	1.87	1.85	1.86	1.71	1.59	1.82	1.64	1.49
Renewables[5]	1.69	1.66	1.66	1.68	1.79	1.83	1.91	1.92	2.02	2.17
Purchased Electricity	3.27	3.40	3.35	3.30	3.67	3.42	3.26	3.73	3.35	3.08
Delivered Energy	**21.17**	**21.57**	**21.09**	**20.86**	**22.81**	**20.62**	**19.68**	**23.00**	**20.44**	**19.22**
Electricity Related Losses	7.13	7.28	7.17	7.06	7.73	7.22	6.87	7.70	6.92	6.36
Total	**28.29**	**28.85**	**28.27**	**27.92**	**30.54**	**27.84**	**26.55**	**30.70**	**27.35**	**25.58**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 2000 dollar)	**4.31**	**4.38**	**4.31**	**4.27**	**4.06**	**3.75**	**3.62**	**3.79**	**3.46**	**3.31**
Onsite Industrial Combined Heat and Power										
Capacity (gigawatts)	25.69	28.05	28.11	28.28	36.43	36.84	37.90	43.57	44.85	47.23
Generation (billion kilowatthours)	139.50	155.16	155.59	156.67	218.02	220.78	227.59	272.50	281.41	296.46

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, biogenic municipal waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs INDFRZN.D030608A, AEO2008.D030208F, and INDHIGH.D032208A.

Table D3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2006	2010		2020		2030	
		Reference	High Technology	Reference	High Technology	Reference	High Technology
Level of Travel							
(billion vehicle miles traveled)							
Light-Duty Vehicles less than 8,500	2693	2777	2777	3375	3379	4069	4074
Commercial Light Trucks[1]	70	73	73	87	87	101	101
Freight Trucks greater than 10,000	235	250	250	304	304	351	351
(billion seat miles available)							
Air	994	1130	1130	1457	1457	1665	1665
(billion ton miles traveled)							
Rail	1656	1702	1703	1932	1933	2147	2148
Domestic Shipping	619	643	643	701	701	721	721
Energy Efficiency Indicators							
(miles per gallon)							
New Light-Duty Vehicle[2]	26.5	27.2	27.6	35.8	36.1	36.6	37.2
New Car[2]	31.1	31.5	32.2	42.0	42.2	42.1	42.6
New Light Truck[2]	23.2	23.7	24.1	31.4	32.2	32.4	33.4
Light-Duty Stock[3]	20.3	20.3	20.3	23.7	23.9	27.9	28.2
New Commercial Light Truck[1]	15.6	15.7	16.0	19.8	20.7	20.2	21.4
Stock Commercial Light Truck[1]	14.3	14.9	14.9	17.4	17.8	19.8	20.6
Freight Truck	6.0	6.0	6.1	6.5	6.7	6.8	7.2
(seat miles per gallon)							
Aircraft	62.2	63.5	63.5	67.2	67.4	70.0	70.6
(ton miles per thousand Btu)							
Rail	2.9	2.9	2.9	3.0	3.1	3.0	3.2
Domestic Shipping	2.0	2.0	2.0	2.0	2.1	2.0	2.2
Energy Use (quadrillion Btu)							
by Mode							
Light-Duty Vehicles	16.41	16.52	16.48	17.10	16.98	17.52	17.37
Commercial Light Trucks[1]	0.62	0.62	0.61	0.63	0.62	0.64	0.62
Bus Transportation	0.26	0.26	0.26	0.27	0.26	0.29	0.27
Freight Trucks	4.89	5.18	5.15	5.85	5.66	6.44	6.14
Rail, Passenger	0.04	0.05	0.05	0.05	0.05	0.06	0.06
Rail, Freight	0.57	0.58	0.58	0.65	0.63	0.72	0.67
Shipping, Domestic	0.32	0.33	0.32	0.35	0.33	0.36	0.33
Shipping, International	0.78	0.79	0.79	0.79	0.79	0.80	0.80
Recreational Boats	0.24	0.25	0.25	0.28	0.28	0.30	0.30
Air	2.65	2.90	2.90	3.61	3.60	4.22	4.18
Military Use	0.69	0.73	0.73	0.73	0.73	0.76	0.76
Lubricants	0.15	0.14	0.14	0.14	0.14	0.15	0.15
Pipeline Fuel	0.59	0.64	0.64	0.69	0.69	0.72	0.72
Total	**28.20**	**28.98**	**28.91**	**31.15**	**30.77**	**32.98**	**32.37**
by Fuel							
Liquefied Petroleum Gases	0.02	0.02	0.02	0.01	0.01	0.01	0.01
E85[4]	0.00	0.00	0.00	0.97	0.98	1.34	1.35
Motor Gasoline[5]	17.20	17.25	17.21	16.56	16.42	15.97	15.78
Jet Fuel[6]	3.16	3.44	3.44	4.15	4.14	4.79	4.75
Distillate Fuel Oil[7]	6.18	6.54	6.51	7.63	7.39	8.98	8.60
Residual Fuel Oil	0.83	0.85	0.85	0.86	0.85	0.87	0.86
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[8]	0.18	0.17	0.17	0.18	0.18	0.18	0.18
Liquid Fuels and Other Petroleum	27.57	28.29	28.21	30.37	29.98	32.15	31.54
Pipeline Fuel Natural Gas	0.59	0.64	0.64	0.69	0.69	0.72	0.72
Compressed Natural Gas	0.02	0.04	0.04	0.07	0.07	0.08	0.08
Electricity	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Delivered Energy	**28.20**	**28.98**	**28.91**	**31.15**	**30.76**	**32.98**	**32.37**
Electricity Related Losses	0.05	0.05	0.05	0.06	0.06	0.06	0.06
Total	**28.25**	**29.03**	**28.96**	**31.21**	**30.82**	**33.04**	**32.43**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[6]Includes only kerosene type.
[7]Diesel fuel for on- and off- road use.
[8]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs AEO2008.D030208F, and TRNHIGH.D031408A.

Table D4. Key Results for Integrated Technology Cases

Consumption and Emissions	2006	2010			2020			2030		
		2008 Technology	Reference	High Technology	2008 Technology	Reference	High Technology	2008 Technology	Reference	High Technology
Energy Consumption by Sector (quadrillion Btu)										
Residential	10.77	11.73	11.66	11.64	12.79	12.30	12.00	13.73	12.88	12.29
Commercial	8.25	8.66	8.62	8.57	10.30	10.03	9.73	11.69	11.30	10.88
Industrial[1]	25.10	26.30	25.82	25.58	28.96	26.70	25.79	30.15	27.70	26.57
Transportation	28.20	28.98	28.98	28.92	31.18	31.15	30.80	33.00	32.98	32.44
Electric Power[2]	39.68	41.77	41.46	41.23	47.34	45.21	43.63	52.40	49.21	45.79
Total	**99.52**	**104.11**	**103.34**	**102.82**	**115.28**	**110.85**	**107.94**	**123.83**	**118.01**	**112.79**
Energy Consumption by Fuel (quadrillion Btu)										
Liquid Fuels and Other Petroleum[3]	40.06	40.69	40.46	40.24	43.25	42.24	41.30	45.16	43.99	42.68
Natural Gas	22.30	24.44	23.93	23.68	25.24	24.01	23.10	24.96	23.39	22.19
Coal	22.50	23.06	23.03	23.01	28.11	25.87	24.82	33.61	29.90	28.00
Nuclear Power	8.21	8.31	8.31	8.31	8.98	9.05	9.15	8.85	9.57	8.99
Renewable Energy[4]	6.27	7.42	7.43	7.39	9.52	9.50	9.39	11.02	10.97	10.75
Other[5]	0.19	0.19	0.18	0.18	0.18	0.17	0.17	0.23	0.20	0.18
Total	**99.52**	**104.11**	**103.34**	**102.82**	**115.28**	**110.85**	**107.94**	**123.83**	**118.01**	**112.79**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**8.79**	**8.37**	**8.30**	**8.25**	**7.22**	**6.93**	**6.74**	**6.14**	**5.84**	**5.57**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	338	356	355	354	385	374	367	396	372	354
Commercial	213	215	215	215	242	241	238	259	258	257
Industrial[1]	1010	1074	1052	1044	1173	1069	1032	1193	1086	1038
Transportation	1985	1975	1976	1971	2074	2072	2047	2188	2188	2149
Electric Power[6]	2344	2429	2413	2404	2827	2627	2509	3299	2948	2746
Total	**5890**	**6049**	**6011**	**5987**	**6701**	**6384**	**6193**	**7335**	**6851**	**6543**
Carbon Dioxide Emissions by Fuel (million metric tons)										
Petroleum	2581	2565	2555	2546	2692	2650	2607	2816	2767	2701
Natural Gas	1163	1282	1256	1243	1325	1262	1216	1312	1231	1169
Coal	2134	2190	2188	2186	2671	2459	2359	3194	2841	2661
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5890**	**6049**	**6011**	**5987**	**6701**	**6384**	**6193**	**7335**	**6851**	**6543**
Carbon Dioxide Emissions (tons per person)	**19.6**	**19.5**	**19.3**	**19.3**	**19.8**	**18.9**	**18.3**	**20.1**	**18.7**	**17.9**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal waste; other biomass; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste and net electricity imports.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal waste because under international guidelines these are accounted for as waste, not energy.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs HTECHCOST.D031408A, AEO2008.D030208F, and LTECHCOST.D032208A.

Table D5. Key Results for Advanced Nuclear Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2006	2010			2020			2030		
		High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost
Capacity										
Coal	309.8	316.0	316.0	316.0	343.8	343.1	341.5	415.1	406.1	389.8
Oil and Natural Gas Steam	119.7	118.4	118.4	118.4	92.8	93.3	91.4	92.4	92.9	89.9
Combined Cycle	176.5	190.0	190.0	190.0	196.8	196.7	196.8	213.5	210.0	208.4
Combustion Turbine/Diesel	130.9	137.4	137.4	137.4	132.1	132.1	132.0	162.9	164.7	162.3
Nuclear Power	100.2	100.9	100.9	100.9	108.9	110.9	113.6	104.4	114.9	136.6
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	96.3	111.6	111.6	111.6	123.6	123.6	123.5	133.1	132.5	131.2
Distributed Generation (Natural Gas)	0.0	0.3	0.3	0.3	2.6	2.7	2.7	9.1	9.8	9.7
Combined Heat and Power[1]	27.9	30.7	30.7	30.7	40.5	40.4	40.5	51.8	51.8	52.4
Total	**982.9**	**1026.7**	**1026.7**	**1026.7**	**1062.5**	**1064.2**	**1063.5**	**1203.8**	**1204.2**	**1201.8**
Cumulative Additions										
Coal	0.0	7.7	7.7	7.7	37.7	37.0	35.5	109.2	100.2	83.8
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	13.5	13.5	13.5	20.3	20.2	20.3	36.9	33.4	31.8
Combustion Turbine/Diesel	0.0	7.2	7.2	7.2	10.5	10.5	10.3	42.0	43.4	41.9
Nuclear Power	0.0	0.0	0.0	0.0	6.0	8.0	10.7	6.0	16.6	38.2
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	15.2	15.3	15.3	27.3	27.3	27.2	36.8	36.2	34.9
Distributed Generation	0.0	0.3	0.3	0.3	2.6	2.7	2.7	9.1	9.8	9.7
Combined Heat and Power[1]	0.0	2.9	2.9	2.9	12.6	12.5	12.7	23.9	23.9	24.5
Total	**0.0**	**46.7**	**46.8**	**46.8**	**117.0**	**118.2**	**119.3**	**264.0**	**263.5**	**264.8**
Cumulative Retirements	**0.0**	**3.6**	**3.6**	**3.6**	**40.0**	**39.5**	**41.4**	**45.7**	**44.8**	**48.6**
Generation by Fuel (billion kilowatthours)										
Coal	1966	2034	2034	2034	2332	2319	2310	2856	2787	2656
Petroleum	59	50	50	50	53	53	53	57	57	56
Natural Gas	732	821	820	820	724	722	710	610	599	574
Nuclear Power	787	797	797	797	854	868	888	837	917	1082
Pumped Storage	0	1	1	1	1	1	1	1	1	1
Renewable Sources	351	424	424	424	521	522	523	557	558	554
Distributed Generation	0	0	0	0	1	1	1	3	4	4
Combined Heat and Power[1]	152	169	169	169	238	238	239	313	313	317
Total	**4047**	**4294**	**4294**	**4294**	**4723**	**4723**	**4724**	**5234**	**5235**	**5243**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	55	43	43	43	45	45	45	48	48	47
Natural Gas	340	366	365	366	324	323	318	275	272	263
Coal	1938	1992	1993	1992	2259	2247	2241	2675	2615	2515
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2344**	**2413**	**2413**	**2413**	**2641**	**2627**	**2616**	**3010**	**2948**	**2837**
Prices to the Electric Power Sector[2] (2006 dollars per million Btu)										
Petroleum	9.63	10.80	10.79	10.79	8.58	8.57	8.57	10.38	10.37	10.29
Natural Gas	6.87	6.97	6.96	6.97	5.95	5.95	5.92	6.95	6.93	6.85
Coal	1.69	1.84	1.84	1.84	1.72	1.72	1.72	1.80	1.78	1.76

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.

Source: Energy Information Administration, AEO2008 National Energy Modeling System runs HCNUC08.D030308A, AEO2008.D030208F, and LCNUC08.D030308A.

Table D6. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2006	2010			2020			2030		
		High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost
Capacity										
Pulverized Coal	309.3	315.5	315.5	315.5	341.5	338.2	325.3	397.5	376.1	331.7
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	3.1	4.8	17.6	4.7	30.0	94.6
Conventional Natural Gas Combined-Cycle	176.5	190.0	190.0	190.0	192.3	192.1	192.1	194.5	192.1	192.1
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	0.5	4.6	8.7	0.9	17.9	37.4
Conventional Combustion Turbine	130.9	136.6	136.5	136.5	128.2	127.9	127.7	132.1	128.4	125.7
Advanced Combustion Turbine	0.0	0.8	0.9	0.9	7.9	4.2	3.1	37.9	36.3	25.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.2	100.9	100.9	100.9	111.2	110.9	109.9	121.5	114.9	105.4
Oil and Natural Gas Steam	119.7	118.4	118.4	118.4	91.3	93.3	94.6	90.9	92.9	92.6
Renewable Sources/Pumped Storage	117.8	133.1	133.1	133.1	145.5	145.1	144.4	154.1	154.0	150.8
Distributed Generation	0.0	0.3	0.3	0.3	2.7	2.7	1.5	12.6	9.8	5.7
Combined Heat and Power[1]	27.9	30.7	30.7	30.7	40.6	40.4	40.5	52.1	51.8	51.0
Total	**982.9**	**1026.7**	**1026.7**	**1026.7**	**1065.0**	**1064.2**	**1065.4**	**1198.9**	**1204.2**	**1212.8**
Cumulative Additions										
Pulverized Coal	0.0	7.7	7.7	7.7	36.0	32.7	19.8	92.2	70.7	26.4
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	2.5	4.3	17.1	4.2	29.5	94.1
Conventional Natural Gas Combined-Cycle	0.0	13.5	13.5	13.5	15.8	15.5	15.5	17.9	15.5	15.5
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	0.5	4.6	8.7	0.9	17.9	37.4
Conventional Combustion Turbine	0.0	6.4	6.3	6.3	6.9	6.4	6.3	10.7	7.1	6.3
Advanced Combustion Turbine	0.0	0.8	0.9	0.9	7.9	4.2	3.1	37.9	36.3	25.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	8.4	8.0	7.0	23.1	16.6	7.0
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	15.3	15.3	15.3	27.7	27.3	26.6	36.3	36.2	33.0
Distributed Generation	0.0	0.3	0.3	0.3	2.7	2.7	1.5	12.6	9.8	5.7
Combined Heat and Power[1]	0.0	2.9	2.9	2.9	12.8	12.5	12.6	24.2	23.9	23.1
Total	**0.0**	**46.8**	**46.8**	**46.8**	**121.2**	**118.2**	**118.2**	**260.1**	**263.5**	**274.4**
Cumulative Retirements	**0.0**	**3.6**	**3.6**	**3.6**	**41.8**	**39.5**	**38.3**	**46.8**	**44.8**	**47.0**
Generation by Fuel (billion kilowatthours)										
Coal	1966	2034	2034	2034	2334	2319	2319	2749	2787	2917
Petroleum	59	50	50	50	53	53	51	58	57	52
Natural Gas	732	820	820	820	704	722	733	575	599	588
Nuclear Power	787	797	797	797	871	868	861	967	917	845
Renewable Sources/Pumped Storage	351	425	425	425	523	523	524	558	559	553
Distributed Generation	0	0	0	0	1	1	1	4	4	2
Combined Heat and Power[1]	152	169	169	169	240	238	238	315	313	308
Total	**4047**	**4294**	**4294**	**4294**	**4727**	**4723**	**4727**	**5225**	**5235**	**5266**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.48	21.01	21.01	21.01	23.84	23.67	23.54	27.45	27.55	27.62
Petroleum	0.64	0.56	0.56	0.56	0.59	0.59	0.57	0.63	0.63	0.59
Natural Gas	6.42	6.89	6.89	6.89	5.99	6.09	6.12	5.06	5.13	4.83
Nuclear Power	8.21	8.31	8.31	8.31	9.08	9.05	8.98	10.08	9.57	8.81
Renewable Sources	3.74	4.52	4.53	4.52	5.66	5.64	5.66	6.10	6.13	6.06
Total	**39.62**	**41.42**	**41.41**	**41.41**	**45.29**	**45.16**	**45.00**	**49.46**	**49.13**	**48.04**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[3]										
Coal	1938	1992	1993	1992	2263	2247	2235	2608	2615	2623
Petroleum	55	43	43	43	45	45	44	49	48	45
Natural Gas	340	366	365	366	318	323	325	268	272	256
Other[1]	12	12	12	12	12	12	12	12	12	12
Total	**2344**	**2413**	**2413**	**2413**	**2639**	**2627**	**2616**	**2938**	**2948**	**2937**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs HCFOSS08.D030308A, AEO2008.D030208F, and LCFOSS08.D030308A.

Table D7. Key Results for Renewable Technology Cases

Capacity, Generation, and Emissions	2006	2010			2020			2030		
		High Renewable Cost	Reference	Low Renewable Cost	High Renewable Cost	Reference	Low Renewable Cost	High Renewable Cost	Reference	Low Renewable Cost
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	76.72	76.73	76.73	76.73	77.35	77.26	77.13	77.35	77.32	77.32
Geothermal[2]	2.29	2.50	2.50	2.50	3.15	3.28	3.26	4.06	4.18	3.96
Municipal Waste[3]	3.39	3.99	3.99	3.92	4.06	4.02	3.96	4.07	4.06	3.97
Wood and Other Biomass[4]	2.01	2.20	2.20	2.20	4.56	4.39	4.53	5.33	5.58	6.48
Solar Thermal	0.40	0.54	0.54	0.54	0.82	0.82	0.82	0.86	0.86	0.86
Solar Photovoltaic	0.03	0.07	0.07	0.07	0.22	0.22	0.22	0.39	0.39	0.39
Wind	11.50	25.61	25.61	25.61	31.53	33.64	36.92	36.57	40.15	43.80
Total	**96.34**	**111.63**	**111.63**	**111.57**	**121.68**	**123.62**	**126.83**	**128.63**	**132.54**	**136.77**
End-Use Sector[5]										
Conventional Hydropower	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Wood and Other Biomass	4.64	4.87	4.89	4.95	8.32	8.57	8.95	11.97	12.60	13.13
Solar Photovoltaic	0.27	0.67	0.67	0.70	1.01	1.13	1.23	1.39	2.80	3.97
Wind	0.04	0.04	0.04	0.04	0.07	0.09	0.11	0.19	0.26	0.33
Total	**6.00**	**6.63**	**6.65**	**6.74**	**10.45**	**10.85**	**11.33**	**14.60**	**16.72**	**18.48**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	1966	2035	2034	2035	2316	2319	2315	2784	2787	2777
Petroleum	59	50	50	50	52	53	53	56	57	56
Natural Gas	732	821	820	820	728	722	720	606	599	593
Total Fossil	**2757**	**2905**	**2903**	**2904**	**3097**	**3093**	**3088**	**3447**	**3443**	**3426**
Conventional Hydropower	285.07	289.47	289.47	289.47	298.51	298.00	297.16	298.72	298.53	298.35
Geothermal	14.84	17.52	17.52	17.52	22.95	23.96	23.80	30.13	31.05	29.32
Municipal Waste[3]	13.46	18.85	18.85	18.30	19.44	19.08	18.67	19.48	19.47	18.70
Wood and Other Biomass[4]	10.97	21.75	22.98	22.42	86.48	77.53	68.58	92.57	82.55	71.51
Dedicated Plants	9.06	10.94	11.06	11.21	28.80	27.74	28.50	34.54	36.64	42.84
Cofiring	1.91	10.80	11.92	11.22	57.68	49.79	40.07	58.03	45.91	28.68
Solar Thermal	0.49	1.15	1.15	1.15	2.04	2.04	2.04	2.18	2.18	2.18
Solar Photovoltaic	0.01	0.16	0.16	0.16	0.52	0.52	0.52	0.96	0.96	0.96
Wind	25.78	72.85	74.13	73.50	89.99	101.23	113.36	105.86	123.18	137.80
Total Renewable	**350.62**	**421.75**	**424.27**	**422.53**	**519.94**	**522.35**	**524.12**	**549.91**	**557.91**	**558.82**
End-Use Sector[5]										
Total Fossil	99	115	115	115	156	157	158	201	198	200
Conventional Hydropower[7]	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	2.06	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.82
Wood and Other Biomass	28.44	29.83	29.98	30.29	55.52	57.00	59.20	83.13	86.99	89.54
Solar Photovoltaic	0.43	1.07	1.07	1.12	1.61	1.85	2.01	2.22	4.76	6.75
Wind	0.06	0.06	0.06	0.06	0.09	0.13	0.15	0.27	0.38	0.48
Total Renewable	**34.22**	**37.02**	**37.17**	**37.53**	**63.30**	**65.05**	**67.43**	**91.69**	**98.19**	**102.84**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]										
Coal	1938	1994	1993	1993	2243	2247	2246	2610	2615	2609
Petroleum	55	43	43	43	45	45	45	48	48	47
Natural Gas	340	366	365	366	326	323	323	275	272	270
Other[8]	12	12	12	12	12	12	12	12	12	12
Total	**2344**	**2414**	**2413**	**2414**	**2625**	**2627**	**2626**	**2945**	**2948**	**2938**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Represents own-use industrial hydroelectric power.
[8]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs HIRENCST08.D030408A, AEO2008.D030208F, and LORENCST08.D030408A.

Table D8. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Natural Gas Prices										
(2006 dollars per million Btu)										
Henry Hub Spot Price	6.73	6.94	6.90	6.86	6.13	5.95	5.69	7.72	7.22	6.66
Average Lower 48 Wellhead Price[1]	6.24	6.19	6.16	6.12	5.45	5.29	5.05	6.90	6.45	5.94
(2006 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[1]	6.42	6.37	6.33	6.30	5.61	5.44	5.20	7.10	6.63	6.11
Dry Gas Production[2]	**18.51**	**19.27**	**19.29**	**19.32**	**19.27**	**19.67**	**20.40**	**18.50**	**19.44**	**20.69**
Lower 48 Onshore	15.04	15.27	15.26	15.26	13.90	14.16	14.70	12.82	13.95	15.21
Associated-Dissolved	1.42	1.41	1.41	1.41	1.29	1.33	1.38	1.10	1.20	1.24
Non-Associated	13.62	13.86	13.85	13.84	12.61	12.83	13.32	11.72	12.76	13.97
Conventional	5.14	4.82	4.81	4.80	3.59	3.47	3.31	3.57	3.23	2.83
Unconventional	8.48	9.04	9.04	9.05	9.02	9.36	10.01	8.15	9.53	11.14
Lower 48 Offshore	3.05	3.58	3.61	3.65	4.18	4.31	4.51	3.32	3.47	3.47
Associated-Dissolved	0.62	0.72	0.73	0.74	0.93	0.97	1.02	0.73	0.77	0.83
Non-Associated	2.43	2.86	2.88	2.91	3.25	3.35	3.49	2.59	2.69	2.64
Alaska	0.42	0.42	0.42	0.42	1.19	1.19	1.19	2.37	2.01	2.01
Supplemental Natural Gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.46**	**3.85**	**3.85**	**3.85**	**3.60**	**3.55**	**3.41**	**3.23**	**3.18**	**2.73**
Pipeline[4]	2.94	2.64	2.64	2.65	1.14	1.18	1.22	0.23	0.33	0.44
Liquefied Natural Gas	0.52	1.21	1.20	1.20	2.46	2.37	2.19	3.00	2.84	2.29
Total Supply	**22.03**	**23.18**	**23.20**	**23.23**	**22.93**	**23.28**	**23.87**	**21.80**	**22.68**	**23.48**
Consumption by Sector										
Residential	4.37	4.80	4.81	4.81	5.13	5.15	5.17	5.12	5.17	5.22
Commercial	2.83	2.95	2.96	2.96	3.35	3.37	3.39	3.63	3.67	3.72
Industrial[5]	6.49	6.94	6.95	6.96	6.88	6.93	6.99	6.76	6.87	7.02
Electric Power[6]	6.24	6.69	6.70	6.72	5.69	5.92	6.36	4.37	4.99	5.49
Transportation[7]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.08	0.09	0.09
Pipeline Fuel	0.58	0.62	0.62	0.62	0.66	0.67	0.69	0.68	0.70	0.72
Lease and Plant Fuel[8]	1.14	1.18	1.18	1.18	1.20	1.22	1.25	1.20	1.23	1.28
Total	**21.66**	**23.23**	**23.25**	**23.28**	**22.98**	**23.33**	**23.92**	**21.85**	**22.72**	**23.53**
Discrepancy[9]	**0.37**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.04**
Lower 48 End of Year Reserves	**202.99**	**219.82**	**220.62**	**221.61**	**209.51**	**219.31**	**237.64**	**176.29**	**200.42**	**233.48**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2006 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.

Sources: 2006 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 consumption based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs OGLTEC08.D030508A, AEO2008.D030208F, and OGHTEC08.D030508A.

Table D9. Liquid Fuels Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Prices (2006 dollars per barrel)										
Imported Low Sulfur Light Crude Oil	66.02	74.11	74.03	73.96	60.00	59.70	59.39	71.11	70.45	70.03
Imported Crude Oil[1]	59.05	65.25	65.18	65.02	51.85	51.55	51.08	61.36	58.66	57.97
Crude Oil Supply										
Domestic Crude Oil Production[2]	5.10	5.88	5.93	5.98	5.94	6.23	6.53	4.98	5.59	5.94
Alaska	0.74	0.69	0.69	0.69	0.69	0.70	0.70	0.29	0.30	0.30
Lower 48 Onshore	2.93	3.08	3.10	3.13	3.08	3.28	3.46	2.88	3.38	3.58
Lower 48 Offshore	1.43	2.12	2.14	2.16	2.17	2.25	2.37	1.80	1.92	2.06
Net Crude Oil Imports	10.09	9.61	9.60	9.58	10.01	9.75	9.53	11.50	11.03	10.78
Other Crude Oil Supply	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	15.24	15.49	15.53	15.56	15.95	15.98	16.06	16.48	16.63	16.72
Other Supply										
Natural Gas Plant Liquids	1.74	1.68	1.68	1.68	1.70	1.72	1.74	1.50	1.57	1.61
Net Product Imports[3]	2.31	1.76	1.72	1.70	1.39	1.37	1.29	1.38	1.26	1.13
Refinery Processing Gain[4]	0.99	1.05	1.05	1.05	1.00	1.00	1.01	0.98	0.99	0.99
Other Supply[5]	0.45	1.04	1.04	1.04	2.00	1.97	1.98	2.44	2.41	2.44
Total Primary Supply[6]	20.74	21.01	21.02	21.03	22.05	22.04	22.08	22.79	22.86	22.89
Liquid Fuels Consumption by Sector										
Residential and Commercial	1.07	1.08	1.08	1.08	1.12	1.13	1.13	1.11	1.12	1.12
Industrial[7]	5.15	5.06	5.06	5.06	4.79	4.79	4.80	4.71	4.73	4.73
Transportation	14.05	14.59	14.60	14.60	15.79	15.79	15.81	16.63	16.66	16.69
Electric Power[8]	0.29	0.25	0.25	0.25	0.26	0.26	0.26	0.28	0.28	0.28
Total	20.65	20.98	20.99	21.00	21.96	21.96	21.99	22.74	22.80	22.83
Discrepancy[9]	0.09	0.03	0.03	0.03	0.08	0.08	0.09	0.05	0.06	0.06
Lower 48 End of Year Reserves (billion barrels)[2]	19.02	19.59	19.89	20.20	19.68	20.78	21.91	17.69	19.89	20.98

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes ethanol (including imports), alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, biodiesel (including imports), natural gas converted to liquid fuel, coal converted to liquid fuel, and biomass converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[8]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[9]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 product supplied data based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 data: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs OGLTEC08.D030508A, AEO2008.D030208F, and OGHTEC08.D030508A.

Table D10. Natural Gas Supply and Disposition, Liquefied Natural Gas Supply Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2010			2020			2030		
		Low LNG Supply	Reference	High LNG Supply	Low LNG Supply	Reference	High LNG Supply	Low LNG Supply	Reference	High LNG Supply
Dry Gas Production[1]	**18.51**	**19.46**	**19.29**	**19.30**	**20.52**	**19.67**	**18.57**	**20.63**	**19.44**	**16.86**
Lower 48 Onshore	15.04	15.39	15.26	15.26	14.94	14.16	13.19	14.74	13.95	11.75
Associated-Dissolved	1.42	1.41	1.41	1.41	1.34	1.33	1.33	1.20	1.20	1.19
Non-Associated	13.62	13.98	13.85	13.85	13.61	12.83	11.86	13.54	12.76	10.55
Conventional	5.14	4.87	4.81	4.81	3.74	3.47	3.11	3.53	3.23	2.48
Unconventional	8.48	9.11	9.04	9.04	9.87	9.36	8.75	10.01	9.53	8.08
Lower 48 Offshore	3.05	3.65	3.61	3.61	4.38	4.31	4.19	3.53	3.47	3.10
Associated-Dissolved	0.62	0.73	0.73	0.73	0.97	0.97	0.97	0.78	0.77	0.76
Non-Associated	2.43	2.92	2.88	2.88	3.41	3.35	3.23	2.75	2.69	2.34
Alaska	0.42	0.42	0.42	0.42	1.19	1.19	1.19	2.37	2.01	2.01
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.46**	**3.67**	**3.85**	**3.85**	**2.36**	**3.55**	**5.71**	**1.56**	**3.18**	**8.33**
Pipeline[3]	2.94	2.67	2.64	2.64	1.33	1.18	0.97	0.53	0.33	-0.19
Liquefied Natural Gas	0.52	0.99	1.20	1.20	1.03	2.37	4.74	1.03	2.84	8.53
Total Supply	**22.03**	**23.19**	**23.20**	**23.20**	**22.94**	**23.28**	**24.35**	**22.26**	**22.68**	**25.25**
Consumption by Sector										
Residential	4.37	4.80	4.81	4.81	5.13	5.15	5.19	5.14	5.17	5.27
Commercial	2.83	2.95	2.96	2.96	3.35	3.37	3.40	3.65	3.67	3.77
Industrial[4]	6.49	6.95	6.95	6.95	6.87	6.93	7.04	6.82	6.87	7.19
Electric Power[5]	6.24	6.69	6.70	6.70	5.65	5.92	6.84	4.61	4.99	7.13
Transportation[6]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.08	0.09	0.09
Pipeline Fuel	0.58	0.62	0.62	0.62	0.67	0.67	0.68	0.70	0.70	0.73
Lease and Plant Fuel[7]	1.14	1.19	1.18	1.18	1.25	1.22	1.17	1.29	1.23	1.12
Total	**21.66**	**23.23**	**23.25**	**23.25**	**22.98**	**23.33**	**24.39**	**22.30**	**22.72**	**25.30**
Discrepancy[8]	**0.37**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.04**
Lower 48 End of Year Reserves	**202.99**	**221.15**	**220.62**	**220.63**	**226.28**	**219.31**	**212.07**	**207.46**	**200.42**	**183.11**
Natural Gas Prices										
(2006 dollars per million Btu)										
Henry Hub Spot Price	6.73	7.00	6.90	6.90	6.18	5.95	5.51	7.52	7.22	6.03
Average Lower 48 Wellhead Price[9]	6.24	6.25	6.16	6.16	5.50	5.29	4.89	6.72	6.45	5.37
(2006 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[9]	6.42	6.43	6.33	6.34	5.66	5.44	5.03	6.92	6.63	5.52
Delivered Prices										
(2006 dollars per thousand cubic feet)										
Residential	13.80	12.61	12.52	12.52	11.97	11.74	11.30	13.59	13.30	12.09
Commercial	11.85	11.00	10.91	10.91	10.43	10.20	9.77	12.07	11.78	10.59
Industrial[4]	7.89	7.52	7.43	7.43	6.62	6.40	5.98	7.80	7.50	6.35
Electric Power[5]	7.07	7.25	7.16	7.16	6.33	6.11	5.74	7.41	7.13	6.05
Transportation[10]	14.71	14.09	14.01	14.01	12.74	12.52	12.12	13.49	13.22	12.13
Average[11]	**9.49**	**9.06**	**8.97**	**8.97**	**8.47**	**8.22**	**7.72**	**9.96**	**9.63**	**8.25**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2006 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[11]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 consumption based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LOLNG08.D0305086A, AEO2008.D030208F, and HILNG08.D030508A.

Table D11. Liquid Fuels Supply and Disposition, ANWR Drilling Case
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2010		2020		2030	
		Reference	ANWR	Reference	ANWR	Reference	ANWR
Crude Oil							
Domestic Crude Production[1]	5.10	5.93	5.93	6.23	6.48	5.59	6.28
Alaska	0.74	0.69	0.69	0.70	0.95	0.30	1.01
Lower 48 States	4.36	5.24	5.24	5.53	5.53	5.30	5.27
Net Imports	10.09	9.60	9.60	9.75	9.53	11.03	10.58
Other Crude Supply[2]	0.05	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.24**	**15.53**	**15.53**	**15.98**	**16.00**	**16.63**	**16.86**
Other Supply							
Natural Gas Plant Liquids	1.74	1.68	1.68	1.72	1.73	1.57	1.60
Net Product Imports[3]	2.31	1.72	1.72	1.37	1.37	1.26	1.09
Refinery Processing Gain[4]	0.99	1.05	1.05	1.00	1.01	0.99	1.04
Ethanol[5]	0.36	0.81	0.81	1.41	1.41	1.56	1.54
Biodiesel[5]	0.02	0.04	0.04	0.07	0.07	0.08	0.08
Liquids from Coal	0.00	0.00	0.00	0.15	0.13	0.24	0.20
Liquids from Biomass	0.00	0.00	0.00	0.14	0.14	0.29	0.30
Other[6]	0.07	0.18	0.18	0.21	0.21	0.24	0.25
Total Primary Supply[7]	**20.74**	**21.02**	**21.02**	**22.04**	**22.08**	**22.86**	**22.97**
Liquid Fuels Consumption							
by Fuel							
Liquefied Petroleum Gases	2.05	2.05	2.05	1.86	1.86	1.80	1.80
E85[8]	0.00	0.00	0.00	0.67	0.67	0.92	0.90
Motor Gasoline[9]	9.25	9.59	9.59	9.24	9.24	8.91	8.96
Jet Fuel[10]	1.63	1.66	1.66	2.01	2.01	2.31	2.31
Distillate Fuel Oil[11]	4.17	4.40	4.40	4.91	4.91	5.53	5.53
Residual Fuel Oil	0.69	0.70	0.70	0.69	0.69	0.70	0.70
Other[12]	2.86	2.58	2.58	2.58	2.60	2.62	2.67
by Sector							
Residential and Commercial	1.07	1.08	1.08	1.13	1.13	1.12	1.12
Industrial[13]	5.15	5.06	5.06	4.79	4.80	4.73	4.78
Transportation	14.05	14.60	14.60	15.79	15.80	16.66	16.68
Electric Power[14]	0.29	0.25	0.25	0.26	0.26	0.28	0.28
Total	**20.65**	**20.99**	**20.99**	**21.96**	**21.98**	**22.80**	**22.86**
Discrepancy[15]	**0.09**	**0.03**	**0.03**	**0.08**	**0.10**	**0.06**	**0.11**
Imported Low Sulfur Light Crude Oil Price (2006 dollars per barrel)	66.02	74.03	74.03	59.70	59.46	70.45	69.78
Imported Crude Oil Price[16] (2006 dollars per barrel)	59.05	65.18	65.18	51.55	51.00	58.66	57.32
Import Share of Product Supplied (percent)	60.0	54.2	54.2	51.6	50.5	54.3	51.3
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2006 dollars)	264.86	254.07	254.07	207.19	200.42	261.91	241.11

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes net imports.
[6]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers.
[7]Total crude supply plus all components of Other Supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate and kerosene.
[12]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power (CHP), which produces electricity and other useful thermal energy.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]Weighted average price delivered to U.S. refiners.
ANWR = Arctic National Wildlife Refuge.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 data: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F and ANWR2008.D031008A.

Table D12. Key Results for Coal Cost Cases
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2015			2030			Growth Rate, 2006-2030		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Supply										
Production[1]	1163	1240	1215	1180	1620	1455	1110	1.4%	0.9%	-0.2%
Appalachia	392	347	340	335	365	328	309	-0.3%	-0.7%	-1.0%
Interior	151	189	193	186	241	241	236	2.0%	2.0%	1.9%
West	619	703	682	659	1015	885	565	2.1%	1.5%	-0.4%
Waste Coal Supplied[2]	14	11	14	16	8	12	18	-2.0%	-0.4%	1.1%
Net Imports	-15	-5	-3	0	52	78	118	--	--	--
Total Supply[3]	**1161**	**1245**	**1225**	**1197**	**1681**	**1545**	**1246**	**1.6%**	**1.2%**	**0.3%**
Consumption by Sector										
Residential and Commercial	4	4	4	4	4	4	4	-0.2%	-0.2%	-0.2%
Coke Plants	23	21	21	21	19	18	18	-0.8%	-0.9%	-1.0%
Other Industrial[4]	61	60	60	59	57	58	56	-0.2%	-0.2%	-0.3%
Coal-to-Liquids Heat and Power	0	14	9	6	63	35	8	--	--	--
Coal-to-Liquids Liquids Production	0	12	7	5	53	29	6	--	--	--
Electric Power[5]	1026	1135	1125	1102	1485	1401	1155	1.5%	1.3%	0.5%
Total Coal Use	**1114**	**1245**	**1225**	**1197**	**1681**	**1545**	**1246**	**1.7%**	**1.4%**	**0.5%**
Average Minemouth Price[6]										
(2006 dollars per short ton)	24.63	19.64	23.38	28.25	13.13	23.32	44.23	-2.6%	-0.2%	2.5%
(2006 dollars per million Btu)	1.21	0.98	1.17	1.41	0.67	1.19	2.21	-2.4%	-0.1%	2.5%
Delivered Prices[7]										
(2006 dollars per short ton)										
Coke Plants	92.87	82.67	92.85	105.20	65.65	94.68	131.91	-1.4%	0.1%	1.5%
Other Industrial[4]	51.67	45.43	49.16	54.03	38.70	49.91	69.85	-1.2%	-0.1%	1.3%
Coal to Liquids	--	15.03	14.44	17.29	12.42	20.60	32.23	--	--	--
Electric Power[5]										
(2006 dollars per short ton)	33.85	30.75	34.24	38.95	25.22	35.03	54.10	-1.2%	0.1%	2.0%
(2006 dollars per million Btu)	1.69	1.56	1.74	1.97	1.28	1.78	2.69	-1.1%	0.2%	2.0%
Average	**36.03**	**32.00**	**35.71**	**40.63**	**25.24**	**35.70**	**55.68**	**-1.5%**	**-0.0%**	**1.8%**
Exports[8]	70.93	64.55	71.83	79.72	55.19	79.44	95.10	-1.0%	0.5%	1.2%
Cumulative Electricity Generating Capacity Additions (gigawatts)[9]										
Coal	0.0	22.7	18.4	14.2	134.8	104.2	40.1	--	--	--
Conventional: Pulverized Coal	0.0	18.0	15.8	11.9	99.8	70.7	33.5	--	--	--
Advanced: IGCC	0.0	4.8	2.6	2.3	34.9	33.5	6.6	--	--	--
Petroleum	0.0	0.5	0.5	0.5	0.9	0.9	1.0	--	--	--
Natural Gas	0.0	28.0	28.3	29.8	91.7	94.9	97.6	--	--	--
Nuclear	0.0	0.0	0.0	0.0	6.0	16.6	59.8	--	--	--
Renewables[10]	0.0	22.9	23.2	22.6	47.8	46.9	44.9	--	--	--
Other	0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	--	--	--
Total	**0.0**	**74.1**	**70.5**	**67.1**	**281.0**	**263.5**	**243.4**	--	--	--
Liquids from Coal (million barrels per day)	0.00	0.10	0.06	0.04	0.43	0.24	0.05	--	--	--
Labor Productivity										
Coal Mining (short tons per miner per hour)	6.26	8.36	6.71	5.29	14.93	7.25	2.98	3.7%	0.6%	-3.0%
Rail: Eastern Railroads (billion freight ton-miles per employee per year)	8.58	15.09	12.49	10.29	29.86	17.20	9.77	5.3%	2.9%	0.5%
Rail: Western Railroads (billion freight ton-miles per employee per year)	12.49	18.87	15.56	12.77	33.35	19.08	10.77	4.2%	1.8%	-0.6%

Table D12. Key Results for Coal Cost Cases (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2015			2030			Growth Rate, 2006-2030		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Cost Indices										
(constant dollar index, 2006=1.000)										
Transportation Rate Multipliers										
Eastern Railroads	1.000	1.013	1.031	1.048	0.936	1.006	1.080	-0.3%	0.0%	0.3%
Western Railroads	1.000	1.016	1.031	1.045	0.962	1.018	1.077	-0.2%	0.1%	0.3%
Equipment Costs										
Mining										
Underground	1.000	0.954	1.024	1.098	0.821	1.024	1.275	-0.8%	0.1%	1.0%
Surface	1.000	0.933	1.001	1.073	0.803	1.001	1.246	-0.9%	0.0%	0.9%
Railroads	1.000	0.893	0.967	1.047	0.785	0.987	1.238	-1.0%	-0.1%	0.9%
Average Coal Miner Wage										
(2006 dollars per hour)	**22.08**	**20.58**	**22.08**	**23.67**	**17.71**	**22.08**	**27.49**	**-0.9%**	**0.0%**	**0.9%**

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Production plus waste coal supplied plus net imports.
[4]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal to liquids process.
[5]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes reported prices for both open market and captive mines.
[7]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[8]F.a.s. price at U.S. port of exit.
[9]Cumulative additions after December 31, 2006. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[10]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
Btu = British thermal unit.
IGCC = Integrated gasification combined cycle.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 data based on: Energy Information Administration (EIA), *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007); EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007); Securities and Exchange Commission Form 10K filings (BNSF, Norfolk Southern, and Union Pacific), web site www.sec.gov; CSX Corporation, web site www.csx.com; U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. **Projections:** EIA, AEO2008 National Energy Modeling System runs LCCST08.D030508A, AEO2008.D030208F, and HCCST08.D030508A.

Table D13. Energy Supply, Disposition, Prices, and Emissions, Natural Gas Cases

Supply, Disposition, and Prices	2006	2015				2030			
		Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply	Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply
Production (quadrillion Btu)									
Crude Oil and Lease Condensate	10.80	13.25	12.21	13.27	12.23	12.04	10.17	12.10	10.24
Natural Gas Plant Liquids	2.36	2.29	2.28	2.30	2.28	2.11	2.05	2.32	2.26
Dry Natural Gas	19.04	20.08	19.97	20.30	20.53	20.00	17.46	22.26	19.48
Coal[1]	23.79	24.48	25.22	23.99	24.05	28.63	29.38	21.39	22.33
Nuclear Power	8.21	8.41	8.41	8.29	8.29	9.57	10.12	7.88	7.88
Hydropower	2.89	2.99	3.00	2.99	3.02	3.00	3.01	3.07	3.10
Biomass[2]	2.94	5.12	5.18	5.05	5.04	8.12	8.04	8.46	8.59
Other Renewable Energy[3]	0.88	1.75	1.82	1.74	1.88	2.45	3.05	2.96	3.94
Other[4]	0.50	0.58	0.59	0.58	0.59	0.64	0.64	0.66	0.63
Total	**71.41**	**78.96**	**78.67**	**78.50**	**77.92**	**86.56**	**83.92**	**81.09**	**78.44**
Net Imports (quadrillion Btu)									
Liquid Fuels and Other Petroleum[5]	26.70	24.23	25.26	24.24	25.34	26.52	28.82	26.62	28.96
Natural Gas	3.56	4.15	2.95	4.25	3.05	3.28	2.03	4.70	3.06
Other[6]	-0.28	-0.09	-0.09	-0.01	0.02	1.86	1.98	2.80	2.90
Total	**29.99**	**28.29**	**28.12**	**28.49**	**28.41**	**31.66**	**32.83**	**34.12**	**34.92**
Consumption (quadrillion Btu)									
Liquid Fuels and Other Petroleum[7]	40.06	41.80	41.81	41.80	41.88	43.99	44.79	44.05	44.90
Natural Gas	22.30	24.35	23.05	24.67	23.70	23.39	19.20	27.08	22.26
Coal[8]	22.50	24.19	24.92	23.81	23.88	29.90	30.74	23.91	24.90
Nuclear Power	8.21	8.41	8.41	8.29	8.29	9.57	10.12	7.88	7.88
Hydropower	2.89	2.99	3.00	2.99	3.02	3.00	3.01	3.07	3.10
Biomass[9]	2.50	3.60	3.66	3.53	3.53	5.51	5.47	5.84	5.98
Other Renewable Energy[3]	0.88	1.75	1.82	1.74	1.88	2.45	3.05	2.96	3.94
Other[10]	0.19	0.17	0.17	0.17	0.18	0.20	0.23	0.27	0.33
Total	**99.52**	**107.26**	**106.83**	**107.00**	**106.36**	**118.01**	**116.60**	**115.05**	**113.28**
Prices (2006 dollars per unit)									
Imported Low Sulfur Light Crude Oil (dollars per barrel)	66.02	59.85	60.44	59.86	60.49	70.45	71.62	70.57	71.79
Natural Gas Wellhead Price[11] (dollars per thousand cubic feet)	6.42	5.36	6.13	5.43	6.48	6.63	9.61	7.57	12.55
Coal Minemouth Price[12] (dollars per ton)	24.63	23.38	23.72	28.29	28.43	23.32	23.88	44.35	45.27
Average Electricity Price (cents per kilowatthour)	8.9	8.5	8.8	8.7	9.1	8.8	9.3	10.0	12.1
Carbon Dioxide Emissions by Fuel (million metric tons)									
Petroleum	2581	2636	2638	2637	2644	2767	2837	2787	2862
Natural Gas	1163	1279	1210	1296	1245	1231	999	1427	1157
Coal	2134	2299	2369	2262	2270	2841	2921	2264	2271
Total	**5890**	**6226**	**6229**	**6207**	**6171**	**6851**	**6769**	**6490**	**6303**

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes crude oil, finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke, and electricity.
[7]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol, biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[8]Excludes coal converted to coal-based synthetic liquids.
[9]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[10]Includes non-biogenic municipal waste and net electricity imports.
[11]Represents lower 48 onshore and offshore supplies.
[12]Includes reported prices for both open market and captive mines.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 coal minemouth price: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F, and LOGASSUP.D030408A, HIGASDEM.D030408A, and HDEMLSUP.D030408A.

Table D14. Natural Gas Supply and Disposition, Natural Gas Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2015				2030			
		Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply	Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply
Dry Gas Production[1]	**18.51**	**19.52**	**19.41**	**19.73**	**19.95**	**19.44**	**16.97**	**21.64**	**18.93**
Lower 48 Onshore	15.04	14.81	14.83	14.98	15.30	13.95	12.57	15.65	14.17
Associated-Dissolved	1.42	1.40	1.32	1.40	1.32	1.20	1.00	1.20	1.01
Non-Associated	13.62	13.41	13.51	13.59	13.98	12.76	11.57	14.45	13.16
Conventional	5.14	3.96	4.25	4.02	4.44	3.23	3.86	3.86	4.48
Unconventional	8.48	9.45	9.26	9.56	9.53	9.53	7.71	10.59	8.68
Lower 48 Offshore	3.05	4.32	4.20	4.36	4.27	3.47	3.50	3.62	3.65
Associated-Dissolved	0.62	0.95	0.90	0.95	0.90	0.77	0.72	0.78	0.74
Non-Associated	2.43	3.37	3.30	3.41	3.37	2.69	2.77	2.84	2.90
Alaska	0.42	0.38	0.38	0.38	0.38	2.01	0.90	2.37	1.12
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.46**	**4.03**	**2.87**	**4.13**	**2.96**	**3.18**	**1.97**	**4.57**	**2.97**
Pipeline	2.94	1.91	1.83	1.95	1.93	0.33	0.93	0.74	1.94
Liquefied Natural Gas	0.52	2.12	1.03	2.18	1.03	2.84	1.03	3.83	1.03
Total Supply	**22.03**	**23.61**	**22.34**	**23.92**	**22.98**	**22.68**	**19.00**	**26.27**	**21.96**
Consumption by Sector									
Residential	4.37	5.01	4.95	5.01	4.92	5.17	4.92	5.09	4.74
Commercial	2.83	3.20	3.14	3.19	3.12	3.67	3.46	3.63	3.30
Industrial[3]	6.49	7.00	6.80	6.99	6.74	6.87	5.53	6.49	5.40
Natural Gas-to-Liquids Heat and Power[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.28
Natural Gas-to-Liquids Production[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.38
Electric Power[6]	6.24	6.56	5.65	6.88	6.35	4.99	2.84	8.91	6.06
Transportation[7]	0.02	0.06	0.05	0.06	0.05	0.09	0.08	0.08	0.07
Pipeline Fuel	0.58	0.64	0.61	0.64	0.62	0.70	0.53	0.78	0.58
Lease and Plant Fuel[8]	1.14	1.19	1.19	1.20	1.21	1.23	1.10	1.34	1.19
Total	**21.66**	**23.66**	**22.39**	**23.97**	**23.02**	**22.72**	**18.92**	**26.31**	**22.01**
Lower 48 End of Year Reserves	**202.99**	**227.01**	**209.85**	**228.55**	**212.55**	**200.42**	**156.39**	**214.14**	**165.54**
Natural Gas Prices									
(2006 dollars per million Btu)									
Henry Hub Spot Price	6.73	5.87	6.69	5.94	7.06	7.22	10.37	8.21	13.47
Average Lower 48 Wellhead Price[9]	6.24	5.21	5.96	5.28	6.30	6.45	9.34	7.35	12.20
(2006 dollars per thousand cubic feet)									
Average Lower 48 Wellhead Price[9]	6.42	5.36	6.13	5.43	6.48	6.63	9.61	7.57	12.55
Delivered Prices									
(2006 dollars per thousand cubic feet)									
Residential	13.80	11.54	12.39	11.61	12.74	13.30	16.53	14.26	19.61
Commercial	11.85	9.97	10.80	10.04	11.13	11.78	14.93	12.72	17.94
Industrial[5]	7.89	6.33	7.12	6.41	7.48	7.50	10.61	8.51	13.63
Electric Power[6]	7.07	6.10	6.84	6.19	7.23	7.13	9.90	8.24	13.14
Transportation[10]	14.71	12.71	13.46	12.78	13.80	13.22	16.24	14.17	19.16
Average[11]	**9.49**	**8.00**	**8.89**	**8.06**	**9.18**	**9.63**	**13.13**	**10.27**	**15.67**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[5]Includes any natural gas that is converted into liquid fuel.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Compressed natural gas used as vehicle fuel.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[11]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 consumption based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F, and LOGASSUP.D030408A, HIGASDEM.D030408A, and HDEMLSUP.D030408A.

Table D15. Electricity Generating Capacity, Natural Gas Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity[1]	2006	2015				2030			
		Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply	Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply
Capacity									
Coal	309.8	323.9	336.0	318.3	319.0	406.1	436.3	319.1	336.3
Oil and Natural Gas Steam	119.7	93.6	84.7	99.0	94.5	92.9	83.3	97.6	92.5
Combined Cycle	176.5	192.4	192.3	195.0	194.8	210.0	195.2	289.1	255.3
Combustion Turbine/Diesel	130.9	130.0	123.7	130.8	129.8	164.7	153.3	145.3	144.2
Nuclear Power	100.2	102.1	102.1	102.1	102.1	114.9	121.5	114.9	114.9
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	96.3	117.3	119.1	117.4	118.6	132.5	142.4	138.4	142.6
Distributed Generation (Natural Gas)	0.0	0.9	0.5	1.0	0.4	9.8	5.1	6.0	3.1
Combined Heat and Power[1]	27.9	34.6	34.1	34.6	34.1	51.8	49.9	53.1	53.0
Total	**982.9**	**1016.3**	**1013.8**	**1019.6**	**1014.7**	**1204.2**	**1208.4**	**1185.0**	**1163.4**
Cumulative Additions									
Coal	0.0	17.5	28.3	11.3	11.3	100.2	129.4	12.1	28.6
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	15.8	15.8	18.5	18.3	33.4	18.7	112.6	78.8
Combustion Turbine/Diesel	0.0	8.4	8.1	10.1	9.2	43.4	39.9	25.7	25.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	16.6	23.1	16.6	16.6
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	21.0	22.8	21.1	22.3	36.2	46.1	42.1	46.2
Distributed Generation	0.0	0.9	0.5	1.0	0.4	9.8	5.1	6.0	3.1
Combined Heat and Power[1]	0.0	6.8	6.2	6.7	6.2	23.9	22.0	25.2	25.1
Total	**0.0**	**70.5**	**81.5**	**68.7**	**67.6**	**263.5**	**284.2**	**240.3**	**223.6**
Cumulative Retirements	**0.0**	**38.9**	**52.4**	**33.8**	**37.7**	**44.8**	**61.4**	**40.9**	**45.7**
Generation by Fuel (billion kilowatthours)									
Coal	1966	2154	2235	2115	2122	2787	2904	2136	2256
Petroleum	59	51	52	51	59	57	90	61	152
Natural Gas	732	806	684	848	785	599	310	1218	809
Nuclear Power	787	807	807	795	795	917	970	756	756
Pumped Storage	0	1	1	1	1	1	1	1	1
Renewable Sources	351	469	482	464	474	558	602	613	652
Distributed Generation	0	1	0	2	0	4	2	5	1
Combined Heat and Power[1]	152	197	193	197	193	313	294	318	301
Total	**4047**	**4485**	**4455**	**4473**	**4429**	**5235**	**5174**	**5107**	**4928**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]									
Petroleum	55	44	45	44	51	48	78	54	116
Natural Gas	340	358	308	375	347	272	155	486	331
Coal	1938	2105	2176	2072	2080	2615	2698	2088	2097
Other[3]	12	12	12	12	12	12	12	13	13
Total	**2344**	**2519**	**2541**	**2503**	**2490**	**2948**	**2943**	**2640**	**2557**
Prices to the Electric Power Sector[2] (2006 dollars per million Btu)									
Petroleum	9.63	8.45	8.55	8.47	8.36	10.37	10.10	9.91	10.55
Natural Gas	6.87	5.93	6.66	6.02	7.03	6.93	9.63	8.02	12.78
Coal	1.69	1.74	1.76	1.97	1.98	1.78	1.81	2.69	2.76

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.

Sources: 2006 capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F, and LOGASSUP.D030408A, HIGASDEM.D030408A, and HDEMLSUP.D030408A.

Table D16. Electricity Generating Capacity, Commodity Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2006	2010			2020			2030		
		Low Commodity Cost	Reference	High Commodity Cost	Low Commodity Cost	Reference	High Commodity Cost	Low Commodity Cost	Reference	High Commodity Cost
Capacity										
Coal	309.8	316.0	316.0	316.0	344.4	343.1	337.3	410.9	406.1	393.2
Oil and Natural Gas Steam	119.7	118.4	118.4	118.4	95.6	93.3	92.7	93.4	92.9	92.6
Combined Cycle	176.5	190.0	190.0	190.0	197.6	196.7	193.5	208.9	210.0	209.8
Combustion Turbine/Diesel	130.9	137.4	137.4	137.4	132.1	132.1	140.1	155.8	164.7	176.9
Nuclear Power	100.2	100.9	100.9	100.9	113.6	110.9	102.9	125.2	114.9	98.4
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	96.3	111.6	111.6	111.9	125.4	123.6	120.3	135.2	132.5	124.1
Distributed Generation (Natural Gas)	0.0	0.3	0.3	0.2	4.0	2.7	0.5	16.5	9.8	0.5
Combined Heat and Power[1]	27.9	30.8	30.7	30.8	41.1	40.4	40.0	52.5	51.8	54.1
Total	**982.9**	**1026.7**	**1026.7**	**1026.8**	**1075.4**	**1064.2**	**1048.8**	**1219.7**	**1204.2**	**1171.0**
Cumulative Additions										
Coal	0.0	7.7	7.7	7.7	38.2	37.0	31.5	104.7	100.2	87.6
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	13.5	13.5	13.5	21.1	20.2	16.9	32.4	33.4	33.3
Combustion Turbine/Diesel	0.0	7.2	7.2	7.1	10.1	10.5	20.1	35.6	43.4	56.9
Nuclear Power	0.0	0.0	0.0	0.0	10.7	8.0	0.0	26.8	16.6	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	15.2	15.3	15.5	29.1	27.3	24.0	38.9	36.2	27.8
Distributed Generation	0.0	0.3	0.3	0.2	4.0	2.7	0.5	16.5	9.8	0.5
Combined Heat and Power[1]	0.0	2.9	2.9	2.9	13.3	12.5	12.2	24.6	23.9	26.2
Total	**0.0**	**46.8**	**46.8**	**46.9**	**126.6**	**118.2**	**105.2**	**279.4**	**263.5**	**232.3**
Cumulative Retirements	**0.0**	**3.6**	**3.6**	**3.6**	**36.7**	**39.5**	**42.0**	**45.2**	**44.8**	**46.8**
Generation by Fuel (billion kilowatthours)										
Coal	1966	2034	2034	2033	2343	2319	2235	2809	2787	2664
Petroleum	59	50	50	49	53	53	51	55	57	53
Natural Gas	732	823	820	813	698	722	814	533	599	749
Nuclear Power	787	797	797	797	888	868	812	999	917	789
Pumped Storage	0	1	1	1	1	1	1	1	1	1
Renewable Sources	351	423	424	427	522	522	534	559	558	563
Distributed Generation	0	0	0	0	2	1	1	6	4	1
Combined Heat and Power[1]	152	169	169	169	244	238	235	320	313	325
Total	**4047**	**4296**	**4294**	**4289**	**4750**	**4723**	**4683**	**5282**	**5235**	**5146**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	55	43	43	43	45	45	44	47	48	46
Natural Gas	340	367	365	363	314	323	362	248	272	331
Coal	1938	1993	1993	1991	2269	2247	2164	2623	2615	2502
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2344**	**2414**	**2413**	**2408**	**2640**	**2627**	**2582**	**2931**	**2948**	**2890**
Prices to the Electric Power Sector[2] (2006 dollars per million Btu)										
Petroleum	9.63	10.81	10.79	10.81	8.60	8.57	8.57	10.39	10.37	10.44
Natural Gas	6.87	6.93	6.96	6.99	5.66	5.95	6.34	6.58	6.93	7.55
Coal	1.69	1.84	1.84	1.84	1.72	1.72	1.73	1.77	1.78	1.79
Average Electricity Price (2006 cents per kilowatthour)	**8.9**	**9.1**	**9.2**	**9.2**	**8.4**	**8.6**	**9.0**	**8.5**	**8.8**	**9.7**

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs LC2008.D030308A, AEO2008.D030208F, and HC2008.D030308A.

Table D17. Oil and Gas Supply, Commodity Cost Cases

Production and Prices	2006	2010			2020			2030		
		Low Commodity Cost	Reference	High Commodity Cost	Low Commodity Cost	Reference	High Commodity Cost	Low Commodity Cost	Reference	High Commodity Cost
Crude Oil										
Lower 48 Average Wellhead Price[1] (2006 dollars per barrel)	**60.18**	**79.17**	**78.45**	**78.00**	**52.26**	**52.54**	**52.85**	**60.77**	**60.59**	**62.05**
Production (million barrels per day)[2]										
United States Total	5.10	5.93	5.93	5.89	6.25	6.23	6.18	5.61	5.59	5.29
Lower 48 Onshore	2.93	3.11	3.10	3.10	3.30	3.28	3.23	3.40	3.38	3.05
Lower 48 Offshore	1.43	2.14	2.14	2.10	2.25	2.25	2.25	1.92	1.92	1.95
Alaska	0.74	0.69	0.69	0.69	0.70	0.70	0.70	0.30	0.30	0.30
Lower 48 End of Year Reserves[2] (billion barrels)	**19.02**	**19.91**	**19.89**	**19.79**	**20.86**	**20.78**	**20.60**	**19.94**	**19.89**	**18.79**
Natural Gas										
Prices (2006 dollars per million Btu)										
Henry Hub Spot Price	6.73	6.88	6.90	6.92	5.66	5.95	6.34	6.87	7.22	7.74
Average Lower 48 Wellhead Price[3]	6.24	6.13	6.16	6.17	5.02	5.29	5.65	6.13	6.45	6.92
Prices (2006 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[3]	6.42	6.31	6.33	6.35	5.17	5.44	5.81	6.30	6.63	7.12
Production (trillion cubic feet)	**18.57**	**19.37**	**19.36**	**19.28**	**19.25**	**19.73**	**20.36**	**18.98**	**19.50**	**20.61**
Dry Gas Production[4]	18.51	19.30	19.29	19.21	19.19	19.67	20.29	18.91	19.44	20.55
Lower 48 Onshore	15.04	15.27	15.26	15.23	13.78	14.16	14.66	13.50	13.95	14.62
Lower 48 Offshore	3.05	3.61	3.61	3.56	4.22	4.31	4.44	3.40	3.47	3.56
Alaska	0.42	0.42	0.42	0.42	1.19	1.19	1.19	2.01	2.01	2.37
Supplemental Gaseous Supplies[5]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports (trillion cubic feet)	**3.46**	**3.88**	**3.85**	**3.83**	**3.98**	**3.55**	**3.53**	**3.35**	**3.18**	**3.14**
Pipeline	2.94	2.64	2.64	2.65	1.41	1.18	1.41	0.54	0.33	0.61
Liquefied Natural Gas	0.52	1.24	1.20	1.18	2.57	2.37	2.12	2.81	2.84	2.54
Total Supply (trillion cubic feet)	**22.03**	**23.25**	**23.20**	**23.11**	**23.23**	**23.28**	**23.89**	**22.33**	**22.68**	**23.76**
Consumption by Sector (trillion cubic feet)										
Residential	4.37	4.81	4.81	4.80	5.18	5.15	5.11	5.20	5.17	5.12
Commercial	2.83	2.96	2.96	2.96	3.39	3.37	3.34	3.69	3.67	3.66
Industrial[6]	6.49	6.97	6.95	6.91	7.02	6.93	6.85	6.95	6.87	6.85
Electric Power[7]	6.24	6.72	6.70	6.65	5.75	5.92	6.63	4.55	4.99	6.06
Transportation[8]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.09	0.09	0.08
Pipeline Fuel	0.58	0.62	0.62	0.62	0.67	0.67	0.68	0.69	0.70	0.73
Lease and Plant Fuel[9]	1.14	1.18	1.18	1.17	1.20	1.22	1.25	1.21	1.23	1.29
Total	21.66	23.30	23.25	23.15	23.28	23.33	23.93	22.37	22.72	23.80
Lower 48 End of Year Dry Reserves (trillion cubic feet)	**202.99**	**221.43**	**220.62**	**219.40**	**219.15**	**219.31**	**218.76**	**197.47**	**200.42**	**204.82**
Total Lower 48 Wells Drilled (thousands)	**49.72**	**64.60**	**62.33**	**60.72**	**36.07**	**37.19**	**40.30**	**35.80**	**35.78**	**38.59**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Represents lower 48 onshore and offshore supplies.
[4]Marketed production (wet) minus extraction losses.
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[6]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Compressed natural gas used as vehicle fuel.
[9]Represents natural gas used in field gathering and processing plant machinery.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2006 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). Other 2006 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2008 National Energy Modeling System runs LC2008.D030308A, AEO2008.D030208F, and HC2008.D030308A.

Table D18. Energy Supply, Disposition, and Prices
AEO2008 Reference Case Compared to the Early Release

Supply, Disposition, and Prices	2006	2010		2020		2030	
		Reference	Early-Release Reference	Reference	Early-Release Reference	Reference	Early-Release Reference
Production (quadrillion Btu)							
Petroleum[1]	13.16	15.03	14.92	15.71	16.02	14.15	14.30
Dry Natural Gas	19.04	19.85	19.61	20.24	20.28	20.00	20.41
Coal[2]	23.79	23.97	23.31	25.20	25.61	28.63	31.16
Nuclear Power	8.21	8.31	8.31	9.05	9.15	9.57	9.89
Hydropower	2.89	2.92	2.92	3.00	3.00	3.00	3.00
Biomass[3]	2.94	4.05	4.11	6.42	4.93	8.12	5.52
Other Renewable Energy[4]	0.88	1.51	1.50	2.00	1.99	2.45	2.49
Other[5]	0.50	0.54	0.55	0.58	0.64	0.64	0.72
Total	71.41	76.17	75.22	82.21	81.62	86.56	87.48
Net Imports (quadrillion Btu)							
Petroleum[6]	26.70	23.93	24.49	24.03	26.72	26.52	31.20
Natural Gas	3.56	3.96	4.13	3.66	4.40	3.28	3.51
Other Imports[7]	-0.28	-0.84	-0.26	1.06	1.03	1.86	1.79
Total	29.99	27.04	28.36	28.75	32.15	31.66	36.50
Consumption (quadrillion Btu)							
Liquid Fuels and Other Petroleum[8]	40.06	40.46	40.82	42.24	44.41	43.99	48.23
Natural Gas	22.30	23.93	23.90	24.01	24.83	23.39	24.07
Coal[9]	22.50	23.03	22.94	25.87	26.23	29.90	31.71
Nuclear Power	8.21	8.31	8.31	9.05	9.15	9.57	9.89
Hydropower	2.89	2.92	2.92	3.00	3.00	3.00	3.00
Biomass[10]	2.50	3.01	3.08	4.50	3.83	5.51	4.17
Other Renewable Energy[4]	0.88	1.51	1.50	2.00	1.99	2.45	2.49
Other[11]	0.19	0.18	0.18	0.17	0.18	0.20	0.20
Total	99.52	103.34	103.64	110.85	113.61	118.01	123.76
Prices (2006 dollars per unit)							
Imported Low Sulfur Light Crude Oil Price (dollars per barrel)	66.02	74.03	66.89	59.70	61.05	70.45	71.87
Natural Gas Wellhead Price[12] (dollars per thousand cubic feet)	6.42	6.33	6.09	5.44	5.42	6.63	6.60
Coal Minemouth Price[13] (dollars per ton)	24.63	26.16	24.53	22.51	22.63	23.32	23.45
Average Electricity Price (cents per kilowatthour)	8.9	9.2	9.1	8.6	8.6	8.8	8.8
Liquids Supply and Disposition (million barrels per day)							
Domestic Crude Oil Production[14]	5.10	5.93	5.91	6.23	6.39	5.59	5.63
Net Petroleum Imports	12.41	11.32	11.60	11.12	12.50	12.29	14.46
Natural Gas Plant Liquids	1.74	1.68	1.64	1.72	1.68	1.57	1.61
Refinery Processing Gain[15]	0.99	1.05	1.08	1.00	1.10	0.99	1.14
Biofuels[16]	0.38	0.85	0.84	1.62	1.04	1.93	1.33
of which: Ethanol[17]	0.36	0.81	0.83	1.41	0.96	1.56	1.11
Liquids from Coal	0.00	0.00	0.00	0.15	0.16	0.24	0.58
Other[18]	0.12	0.18	0.18	0.21	0.23	0.24	0.27
Total Primary Supply	20.74	21.02	21.24	22.04	23.10	22.86	25.03
Liquid Fuels Consumption	20.65	20.99	21.18	21.96	23.01	22.80	24.93
Net Import Share of Product Supplied (percent)	60.0	54.2	54.8	51.6	55.0	54.3	59.2
Natural Gas Supply and Disposition (trillion cubic feet)							
Dry Gas Production[19]	18.51	19.29	19.06	19.67	19.70	19.43	19.84
Supplemental Natural Gas[20]	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	3.46	3.85	4.01	3.55	4.28	3.18	3.41
Total Supply	22.03	23.20	23.14	23.28	24.04	22.68	23.31
Total Consumption	21.66	23.25	23.22	23.33	24.12	22.72	23.39

Table D18. Energy Supply, Disposition, and Prices (Continued)
AEO2008 Reference Case Compared to the Early Release

Supply, Disposition, Indicators and Emissions	2006	2010		2020		2030	
		Reference	Early-Release Reference	Reference	Early-Release Reference	Reference	Early-Release Reference
Coal Supply and Disposition (million tons)							
Production	1163	1166	1139	1270	1289	1455	1595
Waste Coal Supplied[21]	14	13	13	11	11	12	13
Net Imports	-15	-34	-11	46	45	78	75
Total Supply	1161	1144	1141	1326	1345	1545	1683
Total Consumption	1114	1145	1141	1327	1344	1545	1682
Macroeconomic Indicators							
Real Gross Domestic Product (billion 2000 chain-weighted dollars)	11319	12453	12555	15984	16177	20219	20832
GDP Chain-type Price Index (2000=1.000)	1.166	1.260	1.267	1.520	1.509	1.871	1.838
Industrial Value of Shipments (billion 2000 dollars)	5821	5997	5882	7113	7044	7997	8226
Nonmanufacturing	1531	1419	1494	1619	1672	1715	1804
Manufacturing	4290	4577	4389	5493	5372	6283	6422
Energy-Intensive	1225	1283	1204	1387	1338	1447	1442
Non-energy Intensive	3065	3295	3185	4107	4034	4836	4980
Real Disposable Personal Income (billion 2000 dollars)	8397	9472	9594	12654	12811	16246	16916
Housing Starts (millions)	1.93	1.68	1.85	1.78	1.84	1.70	1.72
Commercial Floorspace (billion square feet)	74.8	78.8	78.7	89.3	89.3	100.8	100.9
Unit Sales of Light-Duty Vehicles (millions)	16.50	16.38	16.92	17.47	18.72	19.39	20.04
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**8.79**	**8.30**	**8.25**	**6.91**	**7.02**	**5.80**	**5.94**
Carbon Dioxide Emissions (million metric tons)	**5890**	**6011**	**6034**	**6384**	**6646**	**6851**	**7373**

[1]Includes crude oil, lease condensate, and natural gas plant liquids.
[2]Includes waste coal.
[3]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes crude oil, finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes coal, coal coke, and electricity.
[8]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol, biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[9]Excludes coal converted to coal-based synthetic liquids.
[10]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[11]Includes non-biogenic municipal waste and net electricity imports.
[12]Represents lower 48 onshore and offshore supplies.
[13]Includes reported prices for both open market and captive mines.
[14]Includes lease condensate.
[15]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[16]Domestic production and net imports of ethanol, biodiesel, and liquids from biomass.
[17]Includes net imports.
[18]Includes petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, ethers, and renewable fuels such as biodiesel.
[19]Marketed production (wet) minus extraction losses.
[20]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[21]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values: EIA, #PSA#. 2006 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F and AEO2008.D112607A.

Appendix E

NEMS Overview and Brief Description of Cases

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2008* (*AEO2008*) are generated from the National Energy Modeling System (NEMS) [*1*], developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *Annual Energy Outlook* (*AEO*) projections, NEMS is also used in analytical studies for the U.S. Congress, the White House, other offices within the U.S. Department of Energy (DOE), and other Federal agencies. The *AEO* projections are also used by analysts and planners in other government agencies and nongovernment organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the long-term period through 2030, approximately 25 years into the future. In order to represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information among the modules are the delivered prices of energy to end users and the quantities consumed by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply.

The Integrating Module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data structure. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached annually through the long-term horizon. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide, nitrogen oxides, and mercury from the electricity generation sector. The version of NEMS used for *AEO2008* represents current legislation and environmental regulations as of December 31, 2007 (such as the Energy Independence and Security Act of 2007 [EISA2007], which was signed into law on December 19, 2007; the Energy Policy Acts of 2005 [EPACT2005]; the Working Families Tax Relief Act of 2004; and the American Jobs Creation Act of 2004) and the costs of compliance with regulations (such as the Clean Air Interstate Rule and Clean Air Mercury Rule [CAMR], both of which were finalized and published in 2005, and the new stationary diesel regulations issued by the U.S. Environmental Protection Agency [EPA] in July 2006 [*2*].) The potential impacts of pending or proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS.

In general, the historical data used for the *AEO2008* projections were based on EIA's *Annual Energy Review 2006*, published in June 2007 [*3*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2006. CO_2 emissions were calculated by using CO_2 coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2006*, published in November 2007 [*4*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2008* appendix tables indicate the definitions and sources of historical data.

The *AEO2008* projections for years 2007 and 2008 incorporate short-term projections from EIA's January 2008 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to monthly updates of the *STEO* [5].

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices or expenditures of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of macroeconomic drivers to the energy modules, and there is a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, new light-duty vehicle sales, interest rates, and employment. The module uses the following models from Global Insight, Inc.: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Module

The International Module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are a set of crude oil and product supply curves that are available to U.S. markets for each case/scenario analyzed. The petroleum import supply curves are made available to U.S. markets through the Petroleum Market Module (PMM) of NEMS in the form of 5 categories of imported crude oil and 17 international petroleum products, including supply curves for oxygenates and unfinished oils. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international liquids supply and demand (new to *AEO2008*), current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and nonbuilding uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies, and the effects of both building shell and appliance standards, including the recently enacted provisions of the EISA2007. The Commercial Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on a 10-year average and on State-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module projects the consumption of energy for heat and power and for feedstocks and raw materials in each of 21 industries, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the Macroeconomic Activity Module,

the value of shipments is based on NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Bulk chemicals are further disaggregated to organic, inorganic, resins, and agricultural chemicals. A generalized representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the PMM, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module projects consumption of fuels in the transportation sector, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen, by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and industrial shipments. Fleet vehicles are represented separately to allow analysis of the Energy Policy Act of 1992 (EPACT1992) and other legislation and legislative proposals. EPACT2005 is used to assess the impact of tax credits on the purchase of hybrid gas-electric, alternative-fuel, and fuel-cell vehicles. The module also includes a component to assess the penetration of alternative-fuel vehicles. The corporate average fuel economy and biofuel representation in the module reflect the provisions in EISA2007.

The air transportation component explicitly represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets [6]. For air freight shipments, the model represents regional fuel use in narrow-body and wide-body aircraft. An infrastructure constraint limits overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs and macroeconomic variables for costs of capital and domestic investment; enforced environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 (CAAA90) are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated (e.g., fine particulate proposals) are not incorporated. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have recently enacted air emission regulations that affect the electricity generation sector. Where firm State compliance plans have been announced, the regulations are represented in *AEO2008*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits for renewable fuels are incorporated, as currently legislated in EPACT1992 and EPACT2005. EPACT1992 provides a 10-percent tax credit for business investment in solar energy (thermal non-power uses as well as power uses) and geothermal power; those credits have no expiration date. EPACT2005 increases the tax credit to 30 percent for solar energy systems installed before January 1, 2009.

Production tax credits for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants are also represented. They provide a tax credit of up to 1.9 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2008*, new plants coming on line before January 1, 2009, are eligible to receive the credit. Significant changes made for *AEO2008* in the accounting of new renewable energy capacity resulting

from State renewable portfolio standard programs, mandates, and goals will be described in *Assumptions to the Annual Energy Outlook 2008* [7].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and unconventional techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. The module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and imports and exports of liquefied natural gas (LNG).

Crude oil production quantities are used as inputs to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module for determining natural gas prices and quantities. International LNG supply sources and options for construction of new regasification terminals in Canada, Mexico, and the United States, as well as expansions of existing U.S. regasification terminals, are represented, based on the projected regional costs associated with international natural gas supply, liquefaction, transportation, and regasification and world natural gas market conditions.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 U.S. demand regions. The flow of natural gas is determined for both a peak and off-peak period in the year. Key components of pipeline and distributor tariffs are included in separate pricing algorithms.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and biofuels (ethanol, biodiesel, biobutanol, etc.). The module represents refining activities in the five PADDs. It explicitly models the requirements of EISA2007 and CAAA90 and the costs of automotive fuels, such as conventional and reformulated gasoline, and includes the production of biofuels for blending in gasoline and diesel.

AEO2008 represents regulations that limit the sulfur content of all nonroad and locomotive/marine diesel to 15 parts per million (ppm) by mid-2012. The module also reflects the renewable fuels standard (RFS) in EISA2007 that requires the use of 36 billion gallons per year of biofuels by 2022, with corn ethanol limited to 15 billion gallons per year. Demand growth and regulatory changes necessitate capacity expansion for refinery processing units. End-use prices are based on the marginal costs of production, plus markups representing the costs of product marketing and distribution and State and Federal taxes [8]. Refinery capacity expansion at existing sites is permitted in each of the five refining regions modeled.

Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent by volume or less (E10), as well as E85, a blend of up to 85 percent ethanol by volume. Ethanol is produced primarily in the Midwest from corn or other starchy crops, and in the future it may also be produced from cellulosic material, such as switchgrass and poplar. Biodiesel is produced from seed oil, imported palm oil, animal fats, or yellow grease (primarily, recycled cooking oil).

Both domestic and imported ethanol count toward the RFS. Domestic ethanol production is modeled from two feedstocks: corn and cellulosic materials. Corn-based ethanol plants are numerous (more than 100 are now in operation, producing more than 5 billion gallons annually) and are based on a well-known technology that converts sugar into ethanol. Ethanol

from cellulosic sources is a new technology with no pilot plants in operation; however, DOE awarded grants (up to $385 million) in 2007 to construct capacity totaling 147 million gallons per year, which *AEO2008* assumes will be operational in 2012. Imported ethanol may be produced from cane sugar or bagasse, the cellulosic byproduct of sugar milling. The sources of ethanol are modeled to compete on an economic basis and to meet the EISA2007 renewable fuels mandate.

Fuels produced by gasification and Fischer-Tropsch synthesis are modeled in the PMM, based on their economics relative to competing feedstocks and products. The three processes modeled are coal-to-liquids (CTL), gas-to-liquids (GTL), and biomass-to-liquids (BTL). CTL facilities are likely to be built at locations close to coal supplies and water sources, where liquid products and surplus electricity could also be distributed to nearby demand regions. GTL facilities may be built in Alaska, but they would compete with the Alaska Natural Gas Transportation System for available natural gas resources. BTL facilities are likely to be built where there are large supplies of biomass, such as crop residues and forestry waste. Because the BTL process uses cellulosic feedstocks, it is also modeled as a choice to meet the EISA2007 cellulosic biofuels requirement.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by demand region and sector, accounting for minemouth prices, transportation costs, existing coal supply contracts, and sulfur and mercury allowance costs. Over the projection horizon, coal transportation costs in the CMM are projected to vary in response to changes in railroad productivity and the cost of rail transportation equipment and diesel fuel.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports, in the context of world coal trade. The CMM determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export and 20 import regions. U.S. coal production and distribution are computed for 14 supply and 14 demand regions.

Annual Energy Outlook 2008 Cases

Table E1 provides a summary of the cases used to derive the *AEO2008* projections. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed. The following sections describe the cases listed in Table E1. The reference case assumptions for each sector will be described in *Assumptions to the Annual Energy Outlook 2008* [9].at web site www.eia.doe.gov/oiaf/aeo/assumption. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement.

Macroeconomic Growth Cases

In addition to the *AEO2008* reference case, the low economic growth and high economic growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- The *low economic growth case* assumes lower growth rates for population (0.5 percent per year), nonfarm employment (0.5 percent per year), and labor productivity (1.5 percent per year), resulting in higher prices and interest rates and lower growth in industrial output. In the low economic growth case, economic output as measured by real GDP increases by 1.8 percent per year from 2006 through 2030, and growth in real GDP per capita averages 1.3 percent per year.
- The *high economic growth case* assumes higher growth rates for population (1.2 percent per year), nonfarm employment (1.2 percent per year), and labor productivity (2.4 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case, and consequently economic

Table E1. Summary of the *AEO2008* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (2.4 percent per year from 2006 through 2030), world oil price, and technology assumptions. Complete projection tables in Appendix A.	Fully integrated	-	-
Early-Release Reference	Released in 12/2007, this case excludes EISA2007 and other changes in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 3	-
Low Economic Growth	GDP grows at an average annual rate of 1.8 percent from 2006 through 2030. Other assumptions are the same as in the reference case. Partial projection tables in Appendix B.	Fully integrated	p. 54	p. 195
High Economic Growth	GDP grows at an average annual rate of 3.0 percent from 2006 through 2030. Other assumptions are the same as in the reference case. Partial projection tables in Appendix B.	Fully integrated	p. 54	p. 195
Low Price	More optimistic assumptions for worldwide crude oil and natural gas resources and the behavior of the Organization of the Petroleum Exporting Countries (OPEC) than in the reference case. World light, sweet crude oil prices are $42 per barrel in 2030, compared with $70 per barrel in the reference case (2006 dollars). Other assumptions are the same as in the reference case. Partial projection tables in Appendix C.	Fully integrated	p. 50	p. 199
High Price	More pessimistic assumptions for worldwide crude oil and natural gas resources and OPEC behavior than in the reference case. World light, sweet crude oil prices are about $119 per barrel (2006 dollars) in 2030. Other assumptions are the same as in the reference case. Partial projection tables in Appendix C.	Fully integrated	p. 50	p. 199
Residential: 2008 Technology	Future equipment purchases based on equipment available in 2008. Existing building shell efficiencies fixed at 2008 levels. Partial projection tables in Appendix D.	With commercial	p. 59	p. 199
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new construction meet ENERGY STAR requirements after 2016. Partial projection tables in Appendix D.	With commercial	p. 59	p. 199
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available by fuel. Building shell efficiencies for new construction meet the criteria for most efficient components after 2008. Partial projection tables in Appendix D.	With commercial	p. 60	p. 199
Commercial: 2008 Technology	Future equipment purchases based on equipment available in 2008. Building shell efficiencies fixed at 2008 levels. Partial projection tables in Appendix D.	With residential	p. 61	p. 199
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new and existing buildings increase by 8.75 and 6.25 percent, respectively, from 2003 values by 2030. Partial projection tables in Appendix D.	With residential	p. 61	p. 200

Table E1. Summary of the *AEO2008* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available by fuel. Building shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 2003 values by 2030. Partial projection tables in Appendix D.	With residential	p. 62	p. 200
Industrial: 2008 Technology	Efficiency of plant and equipment fixed at 2008 levels. Partial projection tables in Appendix D.	Standalone	p. 65	p. 200
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Partial projection tables in Appendix D.	Standalone	p. 65	p. 200
Transportation: High Technology	Reduced costs and improved efficiencies assumed for advanced technologies. Partial projection tables in Appendix D.	Standalone	p. 66	p. 200
Electricity: Low Nuclear Cost	New nuclear capacity assumed to have 10 percent lower capital and operating costs in 2030 than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 177	p. 201
Electricity: High Nuclear Cost	Costs for new nuclear technology assumed not to improve from 2008 levels in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 177	p. 201
Electricity: Low Fossil Cost	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 178	p. 201
Electricity: High Fossil Cost	New advanced fossil generating technologies assumed not to improve over time from 2008. Partial projection tables in Appendix D.	Fully integrated	p. 178	p. 201
Renewable Fuels: High Renewable Cost	New renewable generating technologies assumed not to improve over time from 2008. Partial projection tables in Appendix D.	Fully integrated	p. 71	p. 201
Renewable Fuels: Low Renewable Cost	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 71	p. 201
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent more rapid improvement than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 76	p. 202
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent slower improvement than in the reference case. Partial projection tables in Appendix D.	Fully Integrated	p. 76	p. 202
Oil and Gas: High LNG Supply	LNG imports exogenously set to a factor times the reference case levels from 2010 forward, with remaining assumptions from the reference case. The factor starts at 1.0 in 2010 and increases linearly to 3.0 by 2030. Partial projection tables in Appendix D.	Fully integrated	p. 49	p. 202
Oil and Gas: Low LNG Supply	LNG imports held constant at 2009 levels, with remaining assumptions from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 49	p. 202
Oil and Gas: ANWR	The Arctic National Wildlife Refuge (ANWR) in Alaska is opened to Federal oil and natural gas leasing, with remaining assumptions from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 183	p. 202

Table E1. Summary of the *AEO2008* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Coal: Low Coal Cost	Productivity for coal mining and coal transportation assumed to increase more rapidly than in the reference case. Coal mining wages, mine equipment, and coal transportation equipment costs assumed to be lower than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 202
Coal: High Coal Cost	Productivity for coal mining and coal transportation assumed to increase more slowly than in the reference case. Coal mining wages, mine equipment, and coal transportation equipment costs assumed to be higher than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 203
Integrated 2008 Technology	Combination of the residential, commercial, and industrial 2008 technology cases; and the electricity high fossil cost, high renewable cost, and high nuclear cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 176	p. 203
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases; and the electricity low fossil cost, low renewable cost, and low nuclear cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 176	p. 203
Integrated Alternative Weather	Assumes future weather resembles 30-year average, as opposed to 10-year average.	Fully integrated	p. 45	p. 203
High Energy Project Cost	Recent cost increases are assumed to continue. Base costs for new electricity generation capacity increase throughout the projection. Capital costs for oil and gas exploration and production (E&P) activities remain at increased levels, as experienced since 2003. Refining costs increase from current costs.	Fully integrated	p. 34	p. 203
Low Energy Project Cost	Recent cost increases are assumed to revert back to lower levels of a few years ago. Base costs for new electricity generation capacity decrease by 15 percent over 10 years, then remain flat. Capital costs for oil and gas E&P fall back toward their pre-2003 levels over time. Refining costs are set to 2004 levels.	Fully integrated	p. 34	p. 203
Limited Electricity Generation Supply	New coal-fired plants are not built unless they include sequestration. Other non-natural-gas capacity restricted to reference case levels or assumed to have higher costs. Existing nuclear units assumed to have lower output than in the reference case.	Fully integrated	p. 38	p. 203
Limited Natural Gas Supply	No Arctic natural gas pipelines are in operation by 2030. LNG import values are held constant at 2009 levels from 2010 forward. Oil and gas resources are 15 percent lower, and the technological progress rate is 50 percent below the rate in the reference case.	Fully integrated	p. 38	p. 204
Combined Limited	Combines all the assumptions of the limited electricity generation supply and limited natural gas supply cases.	Fully integrated	p. 38	p. 204

output grows at a higher rate (3.0 percent per year) than in the reference case (2.4 percent). GDP per capita grows by 1.8 percent per year, compared with 1.6 percent in the reference case.

Price Cases

The world oil price in *AEO2008* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price for light sweet crude oil traded on the New York Mercantile Exchange. *AEO2008* also includes a projection of the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by refiners.

The historical record shows substantial variability in world oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2008* considers three price cases (reference, low price, and high price) to allow an assessment of alternative views on the course of future oil and natural gas prices. In the reference case, world oil prices moderate from 2006 levels through 2016 before beginning to rise to $70 per barrel in 2030 (2006 dollars). The low and high price cases define a wide range of potential price paths (from $42 to $119 per barrel in 2030). The two cases reflect different assumptions about decisions by OPEC members regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources in non-OPEC countries. Because the low and high price cases are not fully integrated with a world economic model, the impact of world oil prices on international economies is not accounted for directly.

- The *reference case* represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources in non-OPEC countries. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's conventional oil production will represent about 40 percent of the world's total liquids production.
- The *low price case* assumes that OPEC countries will increase their conventional oil production to obtain approximately a 44-percent share of total world liquids production, and that conventional oil resources in non-OPEC countries will be more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the reference case. With these assumptions, non-OPEC conventional oil production is higher in the low price case than in the reference case.
- The *high price case* assumes that OPEC countries will continue to hold their production at approximately the current rate, sacrificing market share as global liquids production increases. It also assumes that oil resources in non-OPEC countries will be less accessible and/or more costly to produce than assumed in the reference case.

Buildings Sector Cases

In addition to the *AEO2008* reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes to equipment and building shell efficiencies.

For the residential sector, the three technology-focused cases are as follows:

- The *2008 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2008. Existing building shell efficiencies are assumed to be fixed at 2008 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2008.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*10*]. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. For new construction, building shell efficiencies are assumed to meet the criteria for the most efficient components after 2008.

For the commercial sector, the three technology-focused cases are as follows:

- The *2008 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2008. Building shell efficiencies are assumed to be fixed at 2008 levels.

- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the reference case [*11*]. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 8.75 percent and 6.25 percent higher, respectively, than their 2003 levels—a 25-percent improvement relative to the reference case.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 10.5 percent and 7.5 percent higher, respectively, than their 2003 values—a 50-percent improvement relative to the reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the high renewable and low renewable cost cases, which are discussed in more detail as part of the Renewable Fuels Cases section below. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, these sensitivities analyze the impact of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The *low renewable cost case* assumes greater improvements in residential and commercial PV and wind systems than in the reference case. The low renewable cost assumptions result in capital cost estimates for 2030 that are approximately 10 percent lower than reference case costs for distributed PV technologies.
- The *high renewable cost case* assumes that costs and performance levels for residential and commercial PV and wind systems remain constant at 2008 levels through 2030.

Industrial Sector Cases

In addition to the *AEO2008* reference case, two standalone cases using the Industrial Demand Module of NEMS were developed to examine the effects of less rapid and more rapid technology change and adoption. Because these are standalone cases, the energy intensity changes discussed in this section exclude the refining industry. Energy use in the refining industry is estimated as part of the PMM in NEMS. The Industrial Demand Module was also used as part of the integrated low and high renewable cost cases. For the industrial sector:

- The *2008 technology case* holds the energy efficiency of plant and equipment constant at the 2008 level over the projection period. In this case, delivered energy intensity falls by 1.1 percent annually between 2006 and 2030, as compared with 1.6 percent annually in the reference case. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing composition of industrial output. Because the level and composition of industrial output are the same in the reference, 2008 technology, and high technology cases, any change in energy intensity in the two technology cases is attributable to efficiency changes.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*12*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes (0.7 percent per year, as compared with 0.4 percent per year in the reference case). The same assumption is incorporated in the integrated low renewable cost case, which focuses on electricity generation. Although the choice of 0.7-percent annual rate of improvement in byproduct recovery is an assumption of the high technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Delivered energy intensity falls by 1.9 percent annually in the high technology case.

The 2008 technology case was run with only the Industrial Demand Module, rather than in fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured, and energy consumption and production in the refining industry, which are modeled in the PMM, were excluded.

Transportation Sector Cases

In addition to the *AEO2008* reference case, one standalone case using the Transportation Demand Module of NEMS was developed to examine the effect of more rapid technology change and adoption. For the transportation sector:

- In the *high technology case*, the characteristics of conventional and alternative-fuel light-duty vehicles reflect more optimistic assumptions about

incremental improvements in fuel economy and costs [*13*]. In the freight truck sector, the high technology case assumes more incremental improvement in fuel efficiency for engine and emissions control technologies [*14*]. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail and shipping sectors.

The high technology case was run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices incorporated.

Electricity Sector Cases

In addition to the reference case, four integrated cases with alternative electric power assumptions were developed to analyze uncertainties about the future costs and performance of new generating technologies. Two of the cases examine alternative assumptions for nuclear power technologies, and two examine alternative assumptions for fossil fuel technologies. Reference case values for technology characteristics are determined in consultation with industry and government specialists; however, there is always uncertainty surrounding newer, untested designs. The electricity cases analyze what could happen if costs of advanced designs were either higher or lower than assumed in the reference case. The cases are fully integrated to allow feedback between the potential shifts in fuel consumption and fuel prices.

Nuclear Technology Cases

- The cost assumptions for the *low nuclear cost case* reflect a 10-percent reduction in the capital and operating costs for advanced nuclear technology in 2030, relative to the reference case. The reference case projects an 18-percent reduction in the capital costs of nuclear power plants from 2007 to 2030. The low nuclear cost case assumes a 26-percent reduction between 2007 and 2030.
- The *high nuclear cost case* assumes that capital costs for the advanced nuclear technology do not decline during the projection period but remain fixed at the 2008 levels assumed in the reference case.

Fossil Technology Cases

- In the *low fossil cost case*, capital costs, heat rates, and operating costs for advanced coal and natural gas generating technologies are assumed to be 10 percent lower than reference case levels in 2030. Because learning occurs in the reference case, costs and performance in the low fossil cost case are reduced from initial levels by more than 10 percent. Heat rates in the low fossil cost case fall to between 16 and 31 percent below initial levels, and capital costs are reduced by 19 to 25 percent between 2007 and 2030, depending on the technology.
- In the *high fossil cost case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the projection period but remain fixed at the 2008 values assumed in the reference case.

Additional details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high and low fossil technology cases will be provided in *Assumptions to the Annual Energy Outlook 2008* [*15*].

Renewable Fuels Cases

In addition to the *AEO2008* reference case, two integrated cases with alternative assumptions about renewable fuels were developed to examine the effects of less aggressive and more aggressive improvement in renewable technologies. The cases are as follows:

- In the *high renewable cost case*, capital costs, operating and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2008 levels through 2030.
- In the *low renewable cost case*, the levelized costs of energy for generating technologies using renewable resources are assumed to decline to 10 percent below the reference case costs for the same resources in 2030. For most renewable resources, lower costs are represented by reducing the capital costs of new plant construction. To reflect recent trends in wind energy cost reductions, however, it is assumed that wind plants ultimately achieve the 10-percent cost reduction through a combination of performance improvement (increased capacity factor) and capital cost reductions. Biomass supplies also are assumed to be 10 percent greater for each supply step. Other generating technologies and projection assumptions remain unchanged from those in the reference case. In the low renewable cost case, the rate of improvement in recovery of biomass byproducts from industrial processes is also increased.

Oil and Gas Supply Cases

Two alternative technology cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. In addition, high and low LNG supply cases were developed to examine the impacts of variations in LNG imports on the domestic natural gas market.

- In the *rapid technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the reference case are increased by 50 percent. A number of key E&P technologies for unconventional natural gas also are increased by 50 percent in the rapid technology case. Key supply parameters for Canadian oil and natural gas are also modified to simulate the assumed impacts of more rapid oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model are kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Specific detail by region and fuel category will be provided in *Assumptions to the Annual Energy Outlook 2008* [*16*].
- In the *slow technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the *AEO2008* reference case are reduced by 50 percent. A number of key E&P technologies for unconventional natural gas also are reduced by 50 percent in the slow technology case. Key Canadian supply parameters are also modified to simulate the assumed impacts of slow oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model are kept at the reference case values.
- The *high LNG supply case* exogenously specifies LNG import levels for 2010 through 2030 equal to a factor times the reference case levels. The factor starts at 1.0 in 2010 and linearly increases to 3.0 by 2030. The intent is to project the potential impact on domestic markets if LNG imports turn out to be higher than projected in the reference case.
- The *low LNG supply case* exogenously specifies LNG imports at the 2009 levels projected in the reference case for 2010 through 2030. The intent is to project the potential impact on domestic markets if LNG imports turn out to be lower than projected in the reference case.
- The *ANWR case* assumes that Federal legislation is passed during 2008, which permits Federal oil and gas leasing in ANWR. This case also assumes that oil and natural gas leasing will commence after 2008 in the State and Native lands, which are either in or adjoining ANWR.

Coal Market Cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, and mine equipment costs on the production side, and railroad productivity and rail equipment costs on the transportation side. The alternative productivity and cost assumptions are applied in every year from 2009 through 2030. For the coal cost cases, adjustments to the reference case assumptions for coal mining and railroad productivity are based on variations in growth rates observed in the data for those industries since 1980. The variations in annual productivity growth rates over the historical period are estimated at 3.3 percent for coal mining and 2.5 percent for rail transportation. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the *low coal cost case*, the average annual growth rates for coal mining and railroad productivity are higher than those in the reference case. On the mining side, adjustments to mine productivity are applied at the supply curve level, and adjustments to railroad productivity are made at the regional (East and West) level. As an example, the average growth rate for western railroad productivity is increased from 1.8 percent per year in the reference case to 4.2 percent per year in the low coal cost case. Coal mining wages and mine equipment costs, which remain constant in real dollars in the reference case, are assumed to decline by approximately 1.0 percent per year in real terms in the low coal cost case. Railroad equipment costs, which remain constant in real dollars in the reference case, are assumed to decrease at a rate of 1.0 percent per year in the low coal cost case.

- In the *high coal cost case*, the average annual productivity growth rates for coal mining and railroad productivity are lower than those in the reference case. Coal mining wages and mine equipment costs are assumed to increase by approximately 1.0 percent per year in real terms. Railroad equipment costs also are assumed to increase by 1.0 percent per year.

Additional details about the productivity, wage, and equipment cost assumptions for the reference and alternative coal cost cases are provided in Appendix D.

Cross-Cutting Integrated Cases

In addition to the sector-specific cases described above, a series of cross-cutting integrated cases were used to analyze specific scenarios with broader sectoral impacts. For example, two integrated technology progress cases were formed by combining the assumptions from the other technology progress cases to analyze the broader impact of more rapid and slower technology improvement rates. Another case examined the implications of assuming different levels of heating and cooling degree-days than in the reference case. Two sets of additional cases were analyzed: one set examines the potential impact of uncertainty in energy project costs, and the other set examines the implications of severe demand pressure on the natural gas industry.

Integrated Technology Cases

The *integrated 2008 technology case* combines the assumptions from the residential, commercial, and industrial 2008 technology cases and the electricity high fossil cost, high renewable cost, and high nuclear cost cases. The *integrated high technology case* combines the assumptions from the residential, commercial, industrial, and transportation high technology cases, the electricity high fossil technology case, the low renewables cost case, and the low nuclear cost case.

Integrated Alternative Weather Case

The main cases in *AEO2008* assume a 10-year average for heating and cooling degree-days. The *integrated alternative weather case* assumes a 30-year average for heating and cooling degree-days, in order to examine the impacts of a smaller number of heating and cooling degree-days on energy consumption in the residential, commercial, and electricity generation sectors, as well as on energy prices and CO_2 emissions. Results from this case are summarized in the Issues in Focus section of this report.

Energy Project Cost Cases

Investment in new power plants and new refining and drilling activities depend on the price of certain commodities, such as steel and concrete, that have increased significantly in recent years, as well as other factors such as capital costs for energy equipment and facilities and labor costs. The reference case assumes that investment costs are based on the latest cost data, including any commodity price increases over the past few years, and that they will remain at those levels through 2030; however, there is considerable uncertainty surrounding the future path of commodity prices.

The *high energy project cost case* assumes that costs will continue to rise, leading to increasing investment costs in the energy industry, which are assumed to grow at the historical rate of the past 5 years. Drilling costs in the oil and gas industry are assumed to double from 2006 to 2030, and the costs of steel and other materials are assumed to increase the cost of construction for LNG liquefaction facilities and the cost of the Alaska pipeline.

The *low energy project cost case* assumes that costs will decline gradually, back to the levels of the early 2000s. Results from these two case are summarized in the Issues in Focus section of this report. Additional details will be provided in *Assumptions to the Annual Energy Outlook 2008* [17].

Limited Electricity Generation Supply, Limited Natural Gas Supply, and Combined Limited Cases

Considerable uncertainty surrounds the types of new generating capacity that will be built in the electricity generation sector, depending on potential environmental legislation and technological hurdles for new designs and alternative fuel sources. The volume of recoverable undiscovered natural gas resources, the costs associated with producing those resources, and the potential for bringing new sources of supply to markets in the lower 48 States, either by Arctic pipeline or as LNG, also are uncertain. Three cases were developed to analyze these uncertainties.

The *limited electricity generation supply case* focuses only on the potential challenges facing non-natural-gas generating technologies. This case assumes that, due to the uncertainty of future environmental requirements, no new coal-fired plants will be built unless they include carbon sequestration. It also assumes that new builds of nuclear, wind and biomass will be restricted to reference case levels. New

non-gas capacity, including sequestration and other renewables, is assumed to cost 25 percent more than in the reference case. Output from existing nuclear capacity is also assumed to decline after plants reach 40 years of age due to uncertainties surrounding the ability of older plants to maintain high capacity factors.

The *limited natural gas supply case* examines the impacts of constraints on the development of new natural gas resources. This case assumes that the two large gas pipelines under consideration for development in the Arctic region of North America, to transport gas from the North Slope of Alaska and the MacKenzie Delta to market, will not be in operation by 2030. In the reference case, only the Alaska pipeline is economical, coming on-line in 2020. The *limited natural gas supply case* also assumes that LNG import volumes will remain at 2009 levels through 2030, reflecting the potential inability of the U.S. market to attract significant volumes from the world market. This case also uses an assumption consistent with the *high price case*—a 15-percent reduction in U.S. oil and natural gas resources—and an assumption consistent with the *oil and gas slow technology case*—a 50-percent reduction in the rate of technological progress related to costs, finding rates, and success rates. Like the reference case, the *limited natural gas supply case* also assumes that no additional capacity will be built to produce pipeline-quality natural gas from coal.

The *combined limited case* combines the assumptions of the limited electricity generation supply and limited natural gas supply cases. Results from these three case are summarized in the "Issues in Focus" section of this report. Additional details will be provided in *Assumptions to the Annual Energy Outlook 2008* [*18*].

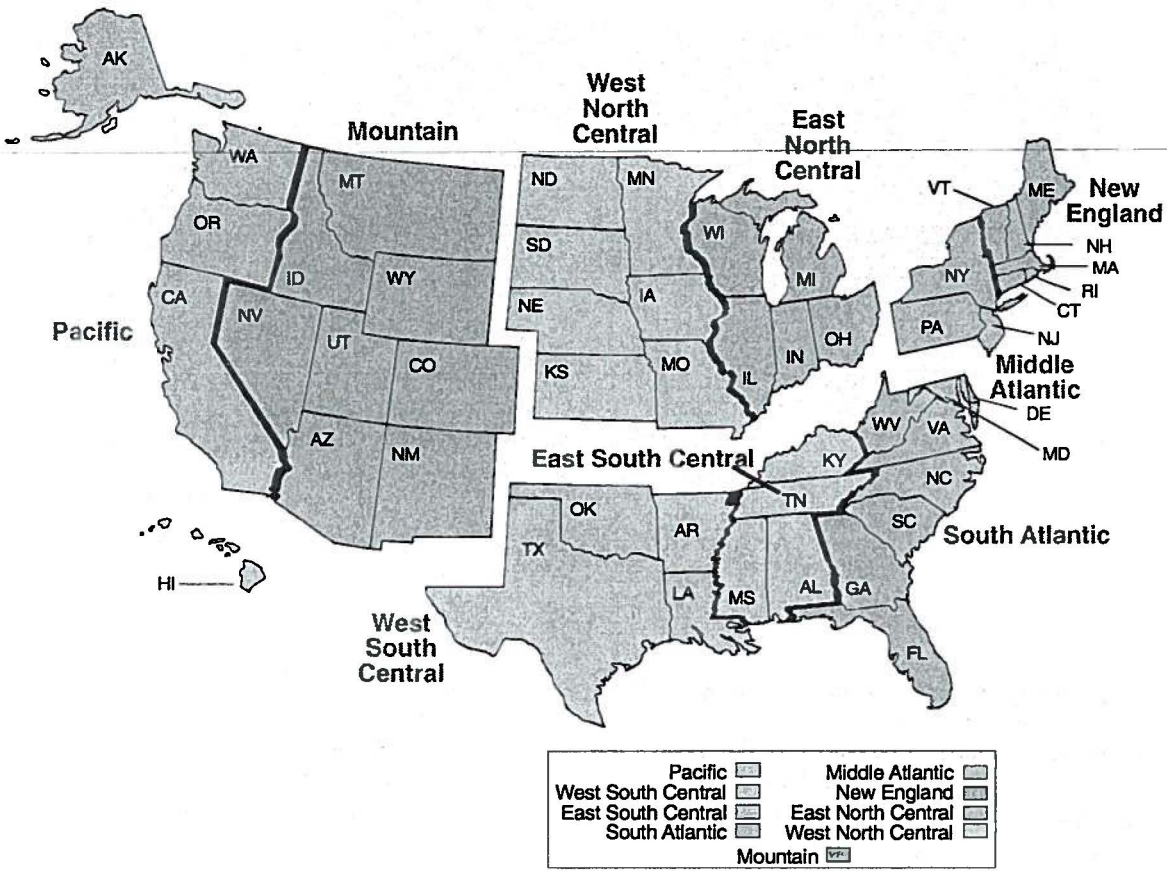
Endnotes

1. Energy Information Administration, *The National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003) (Washington, DC, March 2003).
2. On February 8, 2008, the U.S. Court of Appeals found CAMR to be unlawful and voided it, ruling that the EPA had not proved that mercury was a pollutant eligible for regulation under a less stringent portion of the Clean Air Act; however, EIA did not have time to revise *AEO2008* before publication to remove the impact of CAMR.
3. Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007).
4. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007).
5. Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the NEMS Petroleum Market Module projection.
6. Jet Information Services, Inc., *World Jet Inventory Year-End 2006* (Utica, NY, March 2007); and personal communication from Stuart Miller (Jet Information Services).
7. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554(2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
8. For gasoline blended with ethanol, the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be available through 2010. It is assumed to expire after 2010 under current law.
9. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554(2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
10. High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case Second Edition (Revised)* (Navigant Consulting, Inc., September 2007), and *EIA—Technology Forecast—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., January 2006).
11. High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case Second Edition (Revised)* (Navigant Consulting, Inc., September 2007), and *EIA—Technology Forecast—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., January 2006).
12. These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
13. Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).

14. Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).
15. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554 (2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
16. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554 (2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
17. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554 (2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
18. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554 (2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.

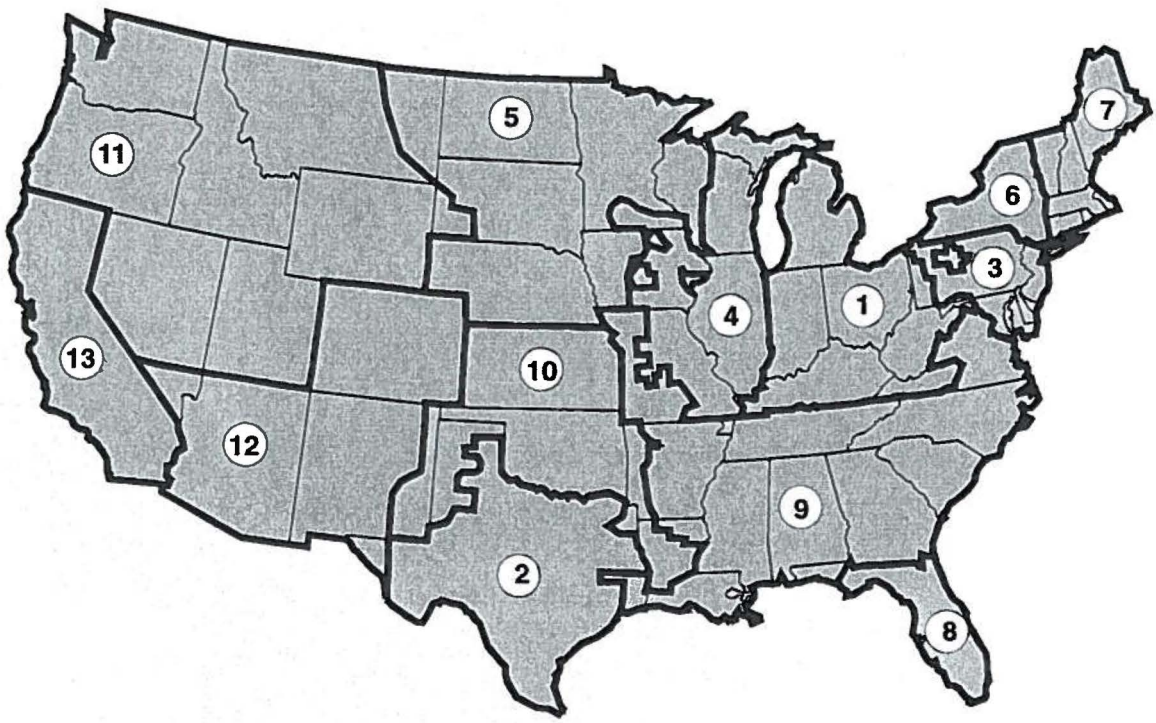
Regional Maps

F1. United States Census Divisions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

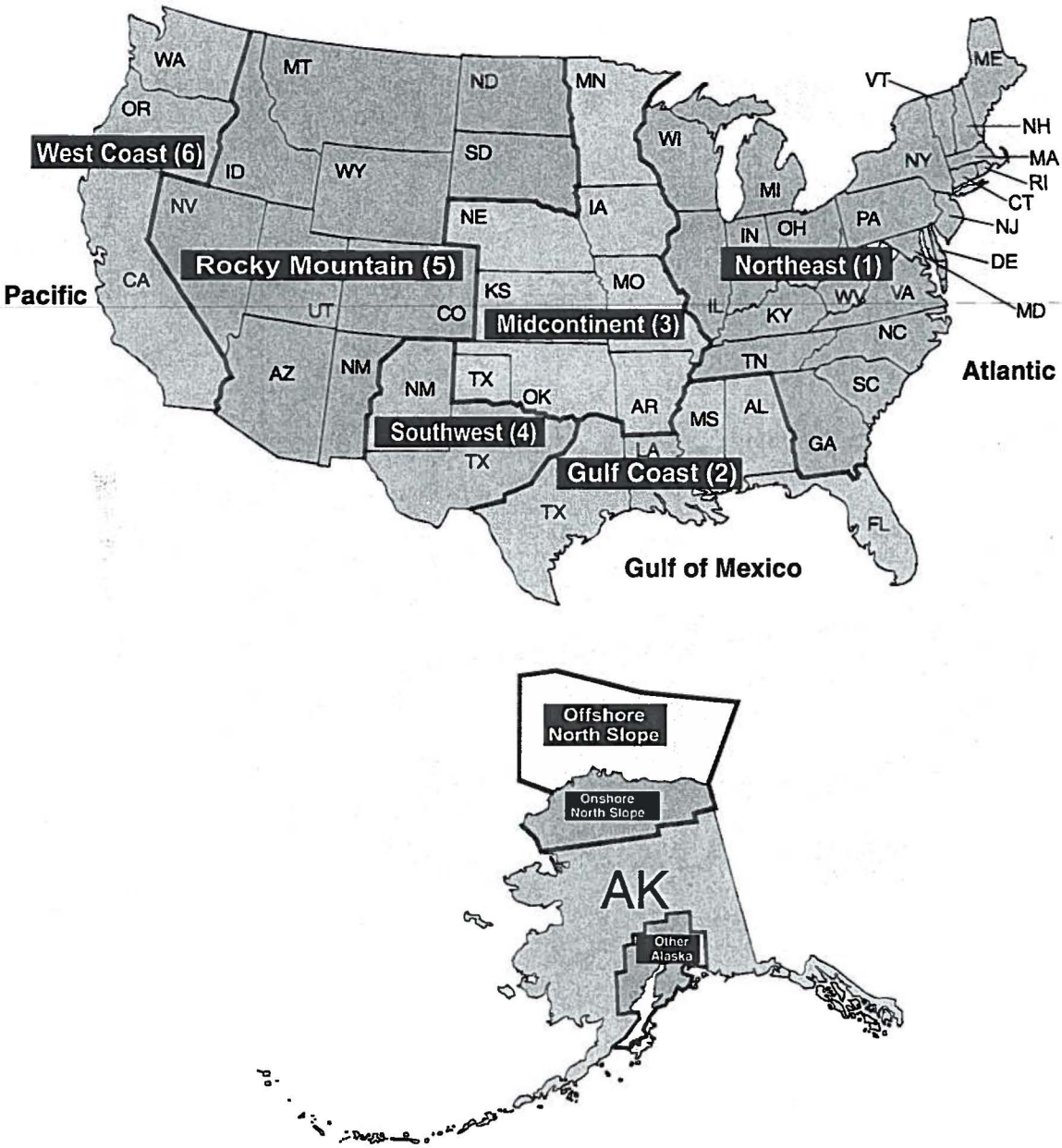
F2. Electricity Market Module Regions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8. Florida Reliability Coordinating Council (FL)
9. Southeastern Electric Reliability Council (SEF
10. Southwest Power Pool (SPP)
11. Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13. California (CA)

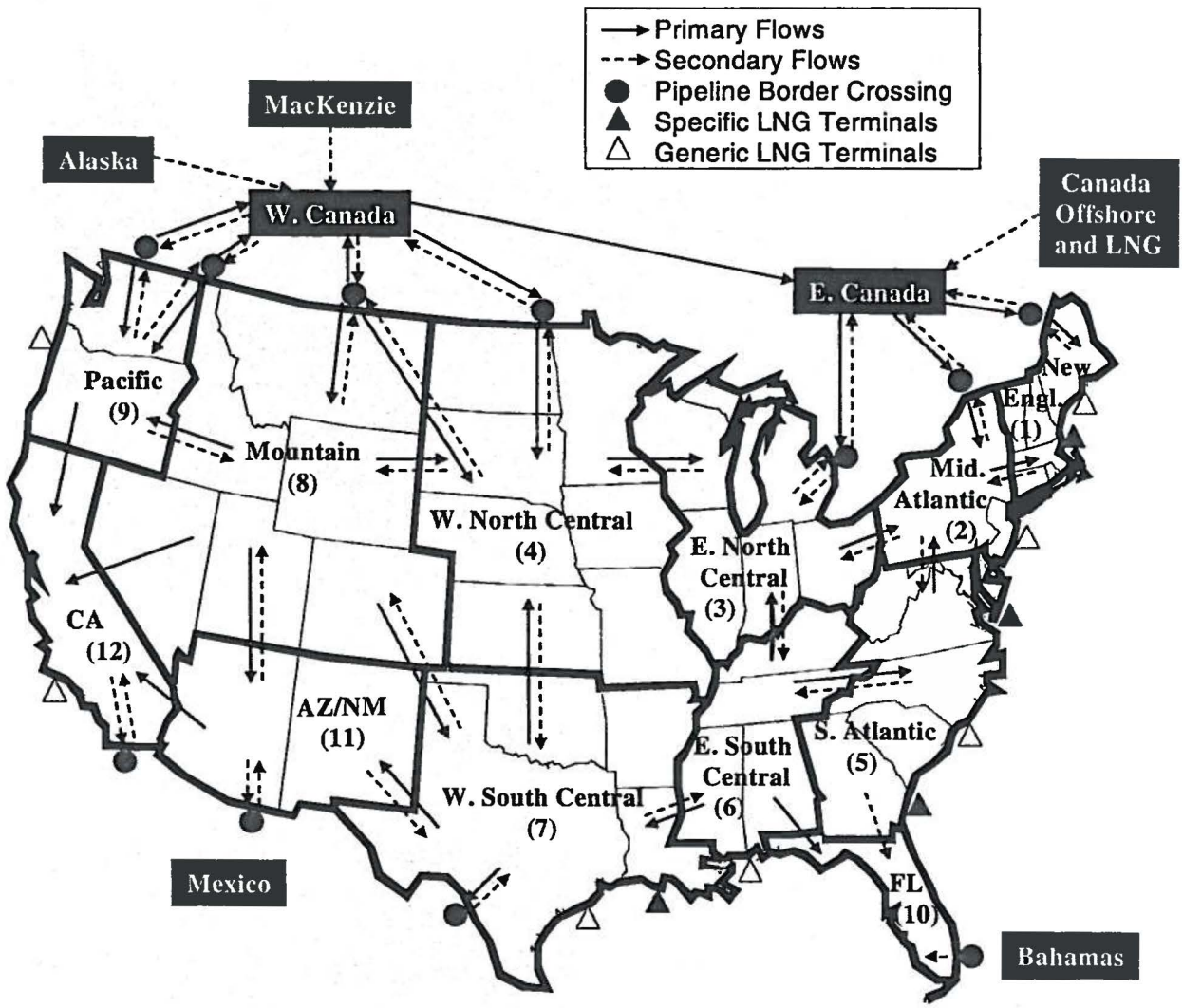
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F3. Oil and Gas Supply Model Regions



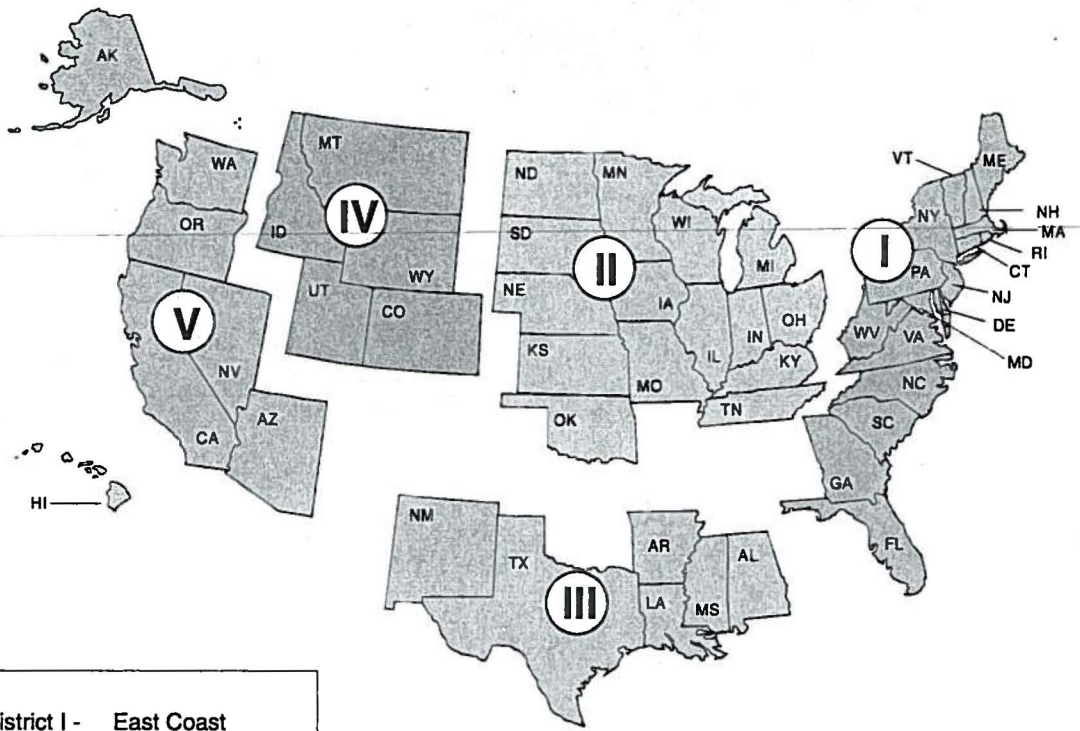
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F4. Natural Gas Transmission and Distribution Model Regions



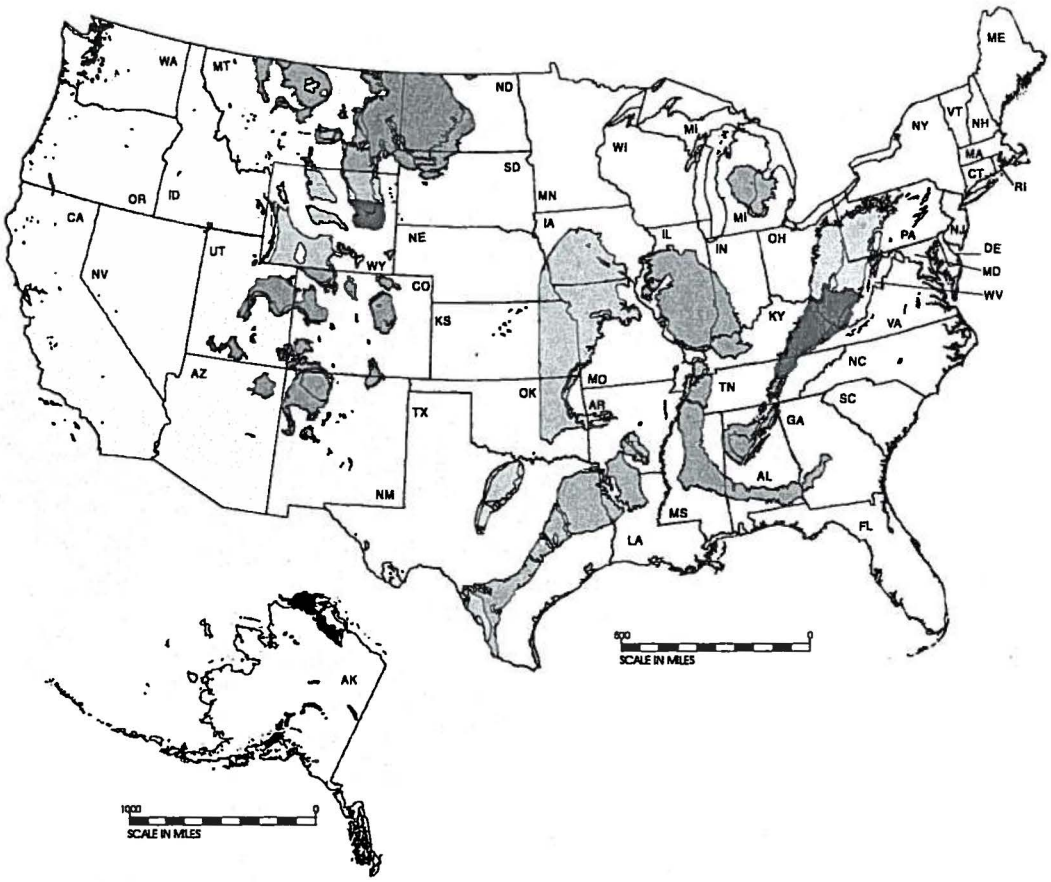
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F5. Petroleum Administration for Defense Districts



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F6. Coal Supply Regions



APPALACHIA
- Northern Appalachia
- Central Appalachia
- Southern Appalachia

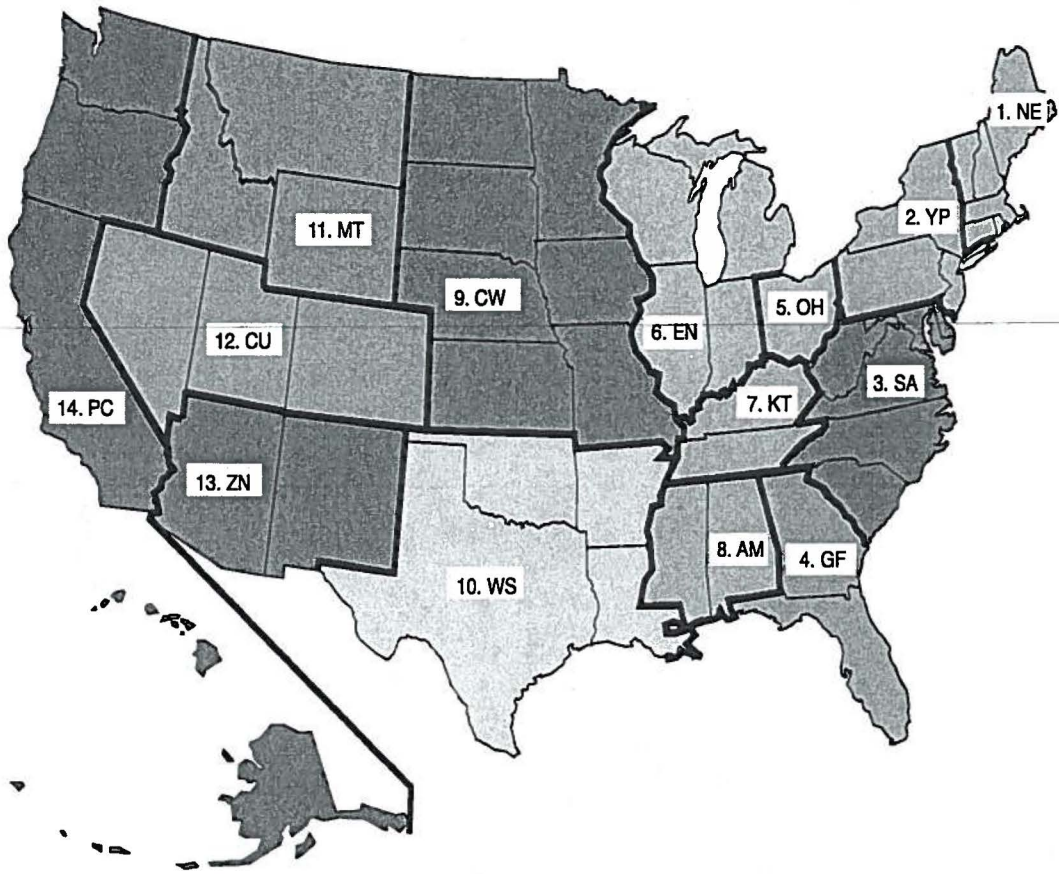
INTERIOR
- Eastern Interior
- Western Interior
- Gulf Lignite

NORTHERN GREAT PLAINS
- Dakota Lignite
- Western Montana
- Wyoming, Northern Powder River Basin
- Wyoming, Southern Powder River Basin
- Western Wyoming

OTHER WEST
- Rocky Mountain
- Southwest
- Northwest

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

Appendix G

Conversion Factors

Table G1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal		
Production	million Btu per short ton	20.310
Consumption	million Btu per short ton	20.183
Coke Plants	million Btu per short ton	26.263
Industrial	million Btu per short ton	21.652
Residential and Commercial	million Btu per short ton	22.016
Electric Power Sector	million Btu per short ton	19.952
Imports	million Btu per short ton	25.073
Exports	million Btu per short ton	25.378
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports	million Btu per barrel	5.980
Liquids		
Consumption	million Btu per barrel	5.338
Motor Gasoline	million Btu per barrel	5.218
Jet Fuel, Kerosene Type	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.790
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas	million Btu per barrel	3.605
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks	million Btu per barrel	5.554
Unfinished Oils	million Btu per barrel	6.118
Imports	million Btu per barrel	5.450
Exports	million Btu per barrel	5.727
Ethanol	million Btu per barrel	3.539
Biodiesel	million Btu per barrel	5.376
Natural Gas Plant Liquids		
Production	million Btu per barrel	3.712
Natural Gas		
Production, Dry	Btu per cubic foot	1,029
Consumption	Btu per cubic foot	1,029
End-Use Sectors	Btu per cubic foot	1,030
Electric Power Sector	Btu per cubic foot	1,028
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.

Note: Conversion factors vary from year to year. Values correspond to those published by EIA for 2006 and may differ slightly from model results.

Sources: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 11-250

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Investigation of Merrimack Station Scrubber Costs and Cost Recovery

PREFILED TESTIMONY OF MICHAEL E. HACHEY
ON BEHALF OF TRANSCANADA POWER MARKETING LTD. AND
TRANSCANADA HYDRO NORTHEAST INC.

ATTACHMENT 19

Brattle Group Analysis – response to DR Deposition 002 – link:
http://www.ctenergy.org/pdf/REVIRP.pdf

Public Service Company of New Hampshire
Docket No. DE 11-250

Date Request Received: 09/16/2013
Request No. DEPOSITION-002
Request from: TransCanada

Date of Response: 11/14/2013
Page 1 of 1

Witness: Gary A. Long

Request:
Is there another Brattle Group analysis that predates August 1st?

Response:
In response to Q-TECH-01-008, PSNH provided a copy of "Documentation Report for Supplemental Analysis Requested by the CEAB via La Capra Associates, Inc.," dated August 1, 2008. That supplemental analysis was performed subsequent to "Integrated Resource Plan for Connecticut" prepared by the Brattle Group dated January 1, 2008, which is available on-line at:
http://www.ctenergy.org/pdf/REVIRP.pdf

Integrated Resource Plan for Connecticut

January 1, 2008

Prepared by:

The Brattle Group

Connecticut Light & Power

The Northeast Utilities System

The United Illuminating Company

The Brattle Group

Marc Chupka
Ahmad Faruqui
Dean Murphy
Samuel Newell
Joseph Wharton

Connecticut Light & Power

The Northeast Utilities System

The United Illuminating Company

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EXECUTIVE SUMMARY

This report is submitted pursuant to Section 51 of PA 07-242, which requires that electric distribution companies submit a comprehensive resource plan to the Connecticut Energy Advisory Board (CEAB). The creation of this report entailed a collaborative effort by The Connecticut Light and Power Company (CL&P), The United Illuminating Company (UI) (together, "the Companies") and *The Brattle Group*, an independent economic consulting firm. *The Brattle Group* conducted a regional electricity market analysis that examined how well selected resource options fared in meeting the performance criteria outlined in PA 07-242 and the CEAB Preferential Criteria for Evaluation of Energy Projects under a broad range of potential future scenarios. The results of that analysis underlie the findings and recommendations outlined below.

FINDINGS

After taking into account planned generation additions, recent and planned transmission projects, and demand-side measures that are planned or underway, and assuming no retirements, new electricity resources will not be needed to attain reliability targets for several years in Connecticut or elsewhere in New England. Under most plausible futures, New England as a whole will need additional resources mid-way through the next decade for reliability related to resource adequacy. As part of the overall New England market, Connecticut will share in this regional resource need, but additional resources located within Connecticut are not required in this time frame for resource adequacy under the scenarios reviewed. Connecticut will not face a localized resource shortfall for many years under the scenarios examined in this report. The overall New England resource need that emerges mid-way through the next decade could be satisfied by resources located either within or outside of Connecticut. Moreover, recent transmission projects and planned generation additions will largely eliminate the critical power flow bottlenecks into and within Southwest Connecticut that have historically made it difficult and costly to serve load there.

Despite the lack of an imminent need for additional resources to satisfy reliability targets, however, we find that Connecticut power prices will continue to be both high and possibly

unstable. This is due primarily to the fact that electricity prices in New England will remain closely linked to natural gas prices, regardless of future events or resource decisions considered in this study. Natural gas prices are volatile and uncertain, and likely to remain fairly high relative to levels experienced in the 1990s. Other important issues for Connecticut's electricity sector include carbon dioxide (CO_2) emissions levels under regional and ultimately national climate policies, the availability and cost of renewable resources to satisfy renewable energy requirements, as well as underlying economic growth and its relationship to future electric load growth. Together, these important concerns can be addressed, at least in part, by resource planning and regulatory policy.

Heavy regional dependence on natural gas for power generation has two potentially harmful implications. First, consumers are exposed to high and uncertain power costs, because gas is the price-setting fuel for electricity. Second, using large amounts of natural gas for electricity generation may increase the potential of gas supply disruptions in the winter months when overall natural gas use peaks (although examining the relationship between using gas as a generation fuel and possible deliverability issues was beyond the scope of this study). But because much of the existing generation base is gas-fired, to substantially change the region's dependence on gas would take a long time and entail exceptional effort and expense. There are supply-side resource options (such as coal or nuclear) that could eventually reduce gas usage for electricity production in New England, but each has capital cost and/or environmental performance issues that may not coincide with other policy objectives. However, enhanced demand-side measures that include energy efficiency can reduce gas usage while helping to meet future resource needs at lower cost and with less environmental impact.

This analysis shows that the potential net benefits of increased DSM – including both energy efficiency and demand response initiatives – are substantial across a range of potential future market conditions. As long as capacity and energy remain expensive, and gas-fired generation is on the margin, reducing capacity needs and energy usage through DSM will be valuable. DSM geared toward energy efficiency can also reduce energy consumption, which can reduce overall energy costs for customers while reducing emissions. (Note that DSM can reduce overall costs, even though under some circumstances, average unit costs (¢/kWh) may actually increase.

When consumption volumes (kWh) change, a change in unit costs may not accurately reflect overall customer impacts. In addition, the effect on particular customers or classes is a question of cost allocation, a ratemaking issue that was not addressed in this study.) It should be noted that the DSM-Focus resource solution represents a very ambitious, program that is unprecedented in New England.

Connecticut and other New England states have ambitious and escalating renewable energy procurement targets. However, the growing demand for renewable electric generation created by these targets may outpace the development of eligible supplies. Connecticut has relatively limited amounts of economically attractive renewable resource options, and New England states on the whole may not achieve their aggregate renewable targets over the next decade. Consequently, the regional price for renewable energy certificates (RECs) could rise above and remain higher than the alternative compliance payment in Connecticut (other states alternative compliance payments are higher than Connecticut's and are likely to set the regional price in a shortage situation). While Connecticut's lower price cap helps contain costs for Connecticut customers, it may also prevent Connecticut load-serving entities (LSEs) from obtaining RECs when regional REC market prices exceed the Connecticut price cap level. Hence, there is a significant possibility that Connecticut's RPS requirements will not be met with renewable electric generation, forcing LSEs increasingly to rely on payments to the state (at $55/MWh) for shortfalls in obtaining renewable energy certificates (RECs). This could place a large economic burden on ratepayers without displacing conventional generation with renewable generation.

Finally, future electricity market prices are likely to vary substantially, depending on future market conditions, particularly the price of natural gas. Analyzing outcomes under a hypothetical cost-of-service regime, in which customers pay for the cost of generation instead of market prices, we find that the range of costs is smaller across different scenarios. Hence, arrangements that incorporate cost-of-service principles could potentially enhance the stability of rates. Although the hypothetical cost-of-service based customer pricing approach examined here did not explore the specific means and conditions under which cost-of-service pricing would yield lower customer costs than market-based pricing, the analysis suggests the potential for

lower prices under cost-of-service pricing under some market conditions, than otherwise might occur in the future External factors remain significant influences on customer costs.

RECOMMENDATIONS

The key findings outlined above are based upon the analysis performed by *The Brattle Group*, and lead to four primary recommendations representing a possible path forward to improve electricity procurement in Connecticut. Steps taken in response to these recommendations could help provide Connecticut customers with reliable, environmentally responsible electric service at more stable prices and potentially lower customer costs.

Recommendation 1: Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.

The potential for increased DSM to reduce customer costs, gas usage, and environmental emissions demonstrated in this analysis suggests that DSM should be pursued more aggressively. State regulatory authorities should examine, and where possible, explore methods to implement additional, cost-effective DSM. This would facilitate utility DSM programs to exceed current levels and expand upon the success of existing DSM programs. While the need for capacity is several years off in Connecticut, DSM programs are more cost-effective if they are pursued consistently over time, so it is reasonable to begin the ramp-up to more aggressive DSM programs in the near term.

The DSM resource investments assumed in this report far exceed the (already aggressive) levels pursued by the Companies to date. The pace and magnitude of this expansion warrants careful monitoring of resource availability, costs, and operational effectiveness as the programs develop over time.

Recommendation 2: Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation.

At the present time, the Companies are constrained to enter into contracts with third-party suppliers with durations not to exceed three years to satisfy standard offer service obligations, which ensures that customers are exposed to power supply prices driven by short-term market prices. Our finding that customer costs would be more stable under a hypothetical cost-of-service regime suggests that supply arrangements incorporating cost-of-service principles could help to stabilize customer rates and potentially, under certain conditions, lower prices for the customer. This could be achieved by providing the Companies greater flexibility in the structures and duration of their power supply arrangements on behalf of customers.

Options may include long-term contracting, procuring energy, capacity and reserve products individually from generators and/or the outright ownership of generating assets, including baseload generation that is not dependent on natural gas. By reducing the extent to which utilities are forced to procure power through short-term contracts driven by regional spot market prices, such alternative procurement options can reduce customers' exposure to uncertain and potentially high gas prices, and may provide to customers some benefits of a diverse fuel mix. Addressing these issues may involve the use of procurement strategies and risk management tools (such as fuel hedging strategies to complement electricity procurement) that go beyond what can be done in a resource planning context. In addition, strategies such as these should be coupled explicitly with the assurance of recovery of supply costs associated with approved long-term power procurement contracts.

Recommendation 3: Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England.

Connecticut's renewable portfolio standard as currently structured, while supporting Connecticut's renewable goals, may impose additional costs on Connecticut customers without

necessarily promoting new renewable generation to displace conventional generation. This observation suggests that additional study of RPS, structure and costs is warranted at both the state and regional level to determine the best ways to meet future RPS requirements. At the state level, for example, the criteria for disbursing funds derived from alternative compliance payments might be re-examined under the current circumstances. Further analysis could also examine the potential to fashion regionally-coordinated policies to address possible renewable shortfalls and/or regional projects in transmission and renewable capacity.

Recommendation 4: Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas.

Non-gas baseload generation (*e.g.*, coal, and nuclear) offers a greater reduction in gas use (particularly in wintertime, when deliverability concerns are highest) than other resource options studied in this report. Although not assessed in this report significant renewable generation could also mitigate gas dependence.

To the extent that market participants' investment in non-gas-fired baseload generation is deemed insufficient to address these risks, state regulatory authorities should consider allowing contractual or ownership arrangements or other policy options to enable or encourage investment in such baseload capacity. Such options should be considered in concert with efforts to reduce dependence on natural gas use in all sectors (*e.g.* heating). Both the cost and CO_2 emissions implications of all non-gas options should be considered.

SECTION I: INTRODUCTION

A. BACKGROUND

On July 1, 2007 Connecticut Public Act 07-242 became effective, which advanced state energy policy in a variety of areas, including efficiency, electric fuel flexibility, peaking generation and the development of other electricity resources. Section 51 of PA 07-242 requires that the electric distribution companies, The Connecticut Light & Power Company (CL&P) and The United Illuminating Company (UI) submit a joint comprehensive resource plan to the Connecticut Energy Advisory Board (CEAB) by January 1, 2008. A full text of Section 51 is attached as Appendix I.

The primary motivation for Section 51 is a desire on the part of the Legislature to engage the Companies in a comprehensive evaluation and planning process in order to support resource procurement. Prior to enactment of PA 07-242, there was no established comprehensive framework to compare potential investments in generation capacity, demand-side measures or transmission enhancements in order to determine their effects on market outcomes, customer costs or other important objectives. Section 51 outlines a process to establish such a framework, and to provide other stakeholders an opportunity to examine and influence the analysis.

In order to perform the required analysis, CL&P and UI (the Companies) issued a Request for Proposals to selected consultants shortly after PA 07-242 was enacted. After receiving proposals from several organizations, the Companies selected *The Brattle Group* to conduct the analysis. *The Brattle Group* is a privately-owned economic consulting firm with practice areas spanning all major energy markets, finance and regulatory and litigation support. Founded in 1990 and headquartered in Cambridge, Massachusetts, *The Brattle Group* has approximately 200 staff with additional offices in Washington DC, San Francisco, CA, London, England and Brussels, Belgium.

This report is the result of an intensely collaborative process involving the Companies and *The Brattle Group*. *The Brattle Group* provided independent expertise and judgment regarding the scope and framework for the analysis, constructed the scenarios, established the myriad

assumptions used in the modeling effort and performed all the analyses. The Companies provided guidance and direction, and helped refine the scenarios and assumptions. *The Brattle Group* and the Companies then interpreted the analysis, identified the primary observations established the key findings, and formulated the recommendations set forth herein.

B. Study Scope

In broad terms, an analysis designed to fulfill the requirements of PA 07-242 will consist of the following steps:

- Quantify the *need* for additional resources across a broad range of uncertain future market conditions (*i.e.*, under different *scenarios*);
- Identify potential *resource solutions* that are consistent with the goals outlined in the statute;
- Evaluate the performance of resource solutions in future scenarios using *metrics* derived from the statute's requirements;
- Recommend resource procurement strategies and provide comments on other policy changes.

The scope of the analysis was set out in the contract between the Companies and *The Brattle Group*, which is attached as Appendix J. All of the primary objectives were met, although several elements could benefit from additional analysis in subsequent versions, as discussed at the end of this report.

C. Limitations

A study of this nature cannot simultaneously provide results on or insights into every conceivable topic with the same degree of depth or confidence. Hence, there are limitations to this analysis, many of which can be addressed in other venues (*e.g.*, DPUC dockets) or in subsequent versions of reports that respond to the annual requirements of PA 07-242 Section 51. In particular, this study was not intended to provide a cost/benefit analysis of transmission options; did not compare the economics of transmission vs. generation or vs. demand-side options; and does not constitute a transmission reliability assessment. Such an assessment would address the mandatory reliability criteria and standards established by various national and

regional bodies, which are applied to the New England transmission system as part of the annual New England Independent System Operator (ISO-NE) Regional System Plan (RSP).

D. Organization of this Report

Because of the broad range of issues considered and the comprehensive nature of the analyses, this report is divided into five main sections. The body of the report describes the background, the analytical approach and key assumptions, discusses the observations and key findings from the analysis, and outlines the recommendations, and finally discusses study limitations and suggested further analyses. A series of appendices follow, which further describe the underpinnings of the analysis or provide a more in-depth discussion of important issues that influenced the analysis. These Appendices are:

Appendix	Topic
A	Electricity Market Analysis
B	Scenario Development
C	Generation Supply Characterization
D	DSM-Focus Resource Solution
E	Renewable Energy
F	CO_2 Reduction Policies
G	DAYZER Model Input Assumptions
H	Evaluation Metrics
I	Section 51 of PA 07-242
J	Consultant Scope of Services

Finally, detailed analysis results for each scenario/resource solution/year are provided in a final section.

SECTION II: ANALYTIC METHODOLOGY

A. OVERVIEW

The current uncertainties in energy markets, the complexities of the ISO-NE markets and the implementation of Connecticut energy policies require an innovative approach to assessing resource strategies. Recent developments in global energy markets, volatility in U.S. electric fuel markets, increased renewable energy requirements, emerging climate policies, rapidly escalating utility construction costs, and continuing evolution in ISO-NE market structure has made long-term electric resource planning extremely challenging. *The Brattle Group* has developed a methodology that captures these elements and yields insights into the impacts of alternative resource solutions.

The major elements of the analysis are:

- **Develop scenarios** spanning the range of plausible future trajectories of exogenous factors that are largely beyond state policy makers' control, including economic growth, fuel prices, and federal climate legislation. Four internally-consistent scenarios are constructed, "Current Trends," "Strict Climate," "High Fuel/Growth," and "Low Stress."
- **Quantify the need for new resources** to reliably meet electricity demand by comparing existing (and planned) resources to the ISO-NE-wide installed capacity requirement and the Connecticut local sourcing requirement established by ISO-NE. The requirements vary by scenario because the load forecast varies.
- **Identify candidate resource solutions**, including supply-side and demand-side resources. The four solutions identified for full analysis are "Conventional Gas Expansion," "DSM-Focus," "Nuclear," and "Coal." Each resource solution was further distinguished by the degree of inclusion of the New England East-West Solution (NEEWS) proposed transmission project – a version with all of NEEWS and a version with the Central Connecticut Reliability Project portion omitted. All solutions are a hybrid of demand-side and a variety of supply-side resources, but each has a different emphasis as indicated by the solution name.

- **Analyze resource solutions across scenarios** and over time (2011, 2013, 2018, and 2030) using electricity market models. This was a comprehensive analysis – with four scenarios, four resource solutions, two NEEWS assumptions and four years, the number of cases analyzed became quite large.
- **Define metrics for evaluating resource solutions** along the policy objectives addressed in Section 51, included customer costs, emissions, and reliability/security. Many of these objectives are also reflected in the CEAB Preferential Criteria for Evaluation of Energy Projects.

B. Scenario Definition

Long-range analyses must address substantial uncertainty regarding external factors, which can have important implications for evaluating potential resource solutions. Key external factors include fuel prices, load growth, and changes in environmental regulation.

In this study, we develop several internally consistent future scenarios against which we evaluate the resource solutions. Each scenario reflects a combination of particular values for the relevant external factors and is characterized by an underlying "driver" in combination with settings of other external factors that are consistent with this driver. The scenarios are designed so that the particular combinations of external factors are relatively likely (factors that tend to "go together"), and/or important (combinations that pose particular risks or opportunities to the resource strategies).

One of the key steps in developing the scenarios is to understand the relationship between the scenario drivers – here, economic growth, fuel price and CO_2 allowance price – and electricity prices and power demand. To create consistent relationship between these, we have considered the interaction between economic growth and electric load, and also the feedback effects by which fuel and CO_2 prices affect power price, which then also influences power demand. Different factors may have varying impact on energy demand vs. peak load, and we have captured this distinction as well.

We have developed four scenarios for this analysis. They are described briefly below, and the table following summarizes the scenarios. A complete description of the underlying drivers and analyses that support the scenario parameters is contained in Appendix B.

Table 2.1: Scenario Summary

Scenario Name	Fuel Prices	Load	Cost / Siting	CO_2 Price
"Current Trends"	Moderate	Moderate	Nominal (high)	Moderate (high)
"Strict Climate"	Slightly High	Slightly Low	Nominal (high)	High
"High Fuel/Growth"	Very High	High	Higher	Somewhat Higher
"Low Stress"	Low	Very High	Moderate	Moderate (high)

i. Current Trends

The Current Trends scenario is based on a continuation of current conditions and expectations. Fuel prices follow current futures prices, and are escalated at growth rates beyond the time horizon of futures prices reported in Energy Information Administration (EIA) forecasts. Load growth is based on ISO-NE Reference Case load growth forecast, which does not incorporate the impact of DSM because DSM is represented as a resource and the load forecast reflects electricity service rather than actual loads. This was adjusted for current and projected levels of DSM to derive a net supply requirement to be supplied by resources other than current and projected levels of DSM. Environmental (climate) policy reflects estimated CO_2 emission allowance prices from the Regional Greenhouse Gas Initiative (RGGI) through 2013, after which moderate federal climate legislation is enacted, resulting in a CO_2 price of about $12/metric tonne in 2014, growing to $26/tonne in 2030 (based on the "safety valve" price cap in the recent Bingaman-Specter proposal, the Low Carbon Economy Act of 2007).[1] Construction costs for new generating capacity assume that recent price increases in materials and labor continue.

[1] The analysis was conducted in real 2008 dollars; unless otherwise indicated, all dollar figures are in 2008 year dollars.

ii. Strict Climate Policy

The Strict Climate Policy scenario is driven primarily by more ambitious federal-level climate policy, based loosely on several of the more stringent legislative proposals that have been introduced recently. This leads to higher CO_2 prices: $26/tonne in 2012, to $60/tonne in 2030, which translates into higher fossil fuel prices in the power sector. The higher CO_2 price causes some dispatch switching (from coal to gas) and likely a shift toward natural gas-fired generation for capacity additions across the U.S., (particularly in coal-dominated regions, not necessarily in New England); this increased natural gas demand pushes up U.S. natural gas prices somewhat (though this is partly tempered by a decrease in non-electric use of natural gas). The overall effect on gas prices is to increase them by about 10% (not including the implicit price increase due to higher CO_2 prices). The high CO_2 price and higher gas price are reflected in higher electricity prices, which cause a reduction in load growth relative to the Current Trends scenario.

iii. High Fuel/Growth

The High Fuel/Growth scenario is characterized by high (regional, national and/or global) economic growth, in combination with substantially higher natural gas prices – up about 70% from level assumed in the Current Trends scenario. High natural gas prices are driven at least in part by high U.S. gas demand (and strong global demand for LNG, which limits its role in holding domestic prices down). Oil prices are also increased by 20-30% from the Current Trends scenario. (At this writing, oil prices have already increased nearly 20% since the Current Trends fuel prices were set for the study.) Electric load growth in this scenario is affected by two strong but opposing factors – high economic growth tends to increase load growth, while higher fuel prices push up power prices, which tends to decrease load relative to what it would otherwise be. On balance, the fuel price increase effect is stronger, and actual load growth in this case is lower than in the Current Trends scenario. Federal climate legislation similar to that in the Current Trends Case is assumed (*e.g.*, a "safety valve" caps CO_2 allowance prices), but the CO_2 allowance price cap is assumed to be set at 30% higher than in the Current Trends scenario. This reflects the greater expense of achieving CO_2 reductions with higher natural gas prices, and the political acceptance of setting a higher "safety valve" price in the context of an era of high economic growth.

iv. Low Stress

Historically, periods of high prices are often followed by a return to earlier, lower price trends. The Lowered Stress scenario reflects a return to somewhat lower fuel costs, reversing some of the recent price increases. Fuel prices are about 40% below their Current Trends levels, with oil and gas maintaining the same proportional relationship as in the Current Trends scenario. Similarly, generation construction costs are lower than in the Current Trends scenario, as some of the recent significant and rapid increases in construction costs abate somewhat over the longer run. In response to the resulting decrease in power prices, load is higher than in the Current Trends scenario. Federal climate legislation similar to that in the Current Trends scenario is assumed.

C. Quantification of Resource Needs

The purpose of this study is to identify the multi-attribute costs and risks associated with various resources options for meeting future electricity needs. Hence the starting point for the study, before describing the *types* of resources, is to quantify the *amount* of new resources that will be needed. Resource needs are driven primarily by reliability concerns: having enough generating capacity installed to serve all demand during the hottest, highest-demand day of the year given the possibility of unplanned generation outages, using a formal criterion that reduces the probability of having inadequate generation to one day in ten years as required by NPCC.[2]

To that end, there are two simultaneous resource adequacy requirements affecting Connecticut customers. One is the ISO-NE-wide installed capacity requirement (ICR), requiring each load serving entity and the system as a whole to have a certain amount of installed capacity. The

[2] ISO-NE must comply with the Northeast Power Coordinating Council's resource adequacy design criterion, which states, "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."
See http://www.npcc.org/documents/regStandards/Criteria.aspx for more information.

second is the Connecticut local sourcing requirement (LSR) requiring a certain minimum amount of capacity to be located in Connecticut.

The analysis projects the necessary amount of new resources (the "resource gap") based solely on these two reliability requirements then examines the economics (and other metrics) of various resource options for meeting that gap. This corresponds to the CEAB Preferential Criteria I.A that resource proposals "meet identified energy needs."[3]

i. ISO-NE Resource Requirements

Forecasting the amount of new supply or demand-side resources that must be installed for reliability involves projecting the demand for electricity, then estimating the amount of resources beyond those that are already in place (or already planned and underway) that will be needed to reliably serve the peak demand in each year. The future demand for electricity is influenced by economic growth and electricity prices – therefore both the demand for electricity and the projected resource gap can vary across future scenarios. The following paragraphs describe the resource gap for the Current Trends scenario, followed by a table describing the resource gap for the other three scenarios.

The load forecast used in the Current Trends scenario is taken directly from the ISO-NE's ten-year hourly energy requirements forecast corresponding to normalized weather conditions and that accounts for transmission and distribution losses. Our understanding is that it is not reduced based on any expected demand response or new energy efficiency programs, so additional adjustments were made to incorporate these programs, as described below.

The amount of resources in place must exceed the forecasted peak load in order to prepare for anomalously hot weather and uncontrollable outages of generating plants. Based on standard probabilistic modeling techniques, ISO-NE has determined that the Installed Capacity Requirement (ICR) must exceed the peak load forecast by 16-17% (varies by year) in order to achieve its target reliability standard, which allows for a loss of load expectation (LOLE) of no

[3] The full text of this criterion reads: "The CEAB will evaluate the consistency of a proposal with forecasted energy needs as identified by the Regional System Operator, the Connecticut Siting Council, the State Energy Plan and other resources that it deems to be relevant and appropriate."

more than one day in ten years. Under ISO-NE rules, installed generating capacity, ISO-callable demand response, and firm imports all count toward the ICR.

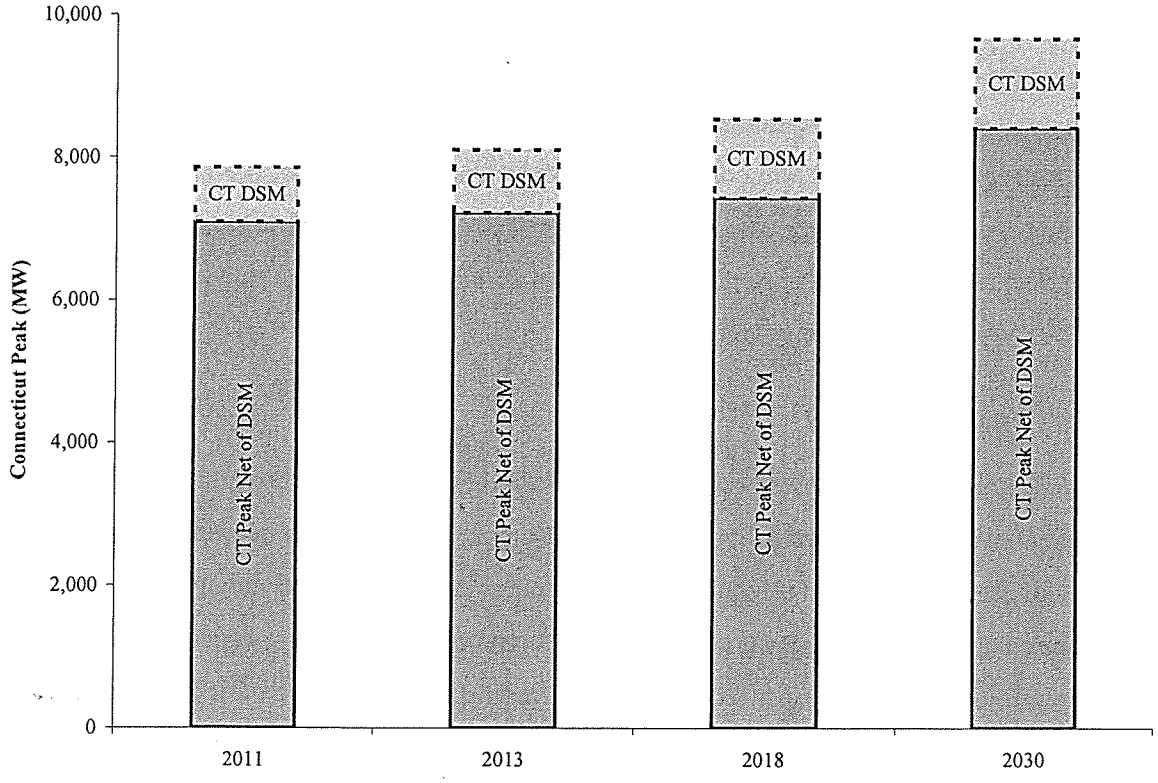
This study also considers planned new resources (described in Appendix A), including:

- 1,107 MW of new generating capacity that is either under construction, under contract or recently operational in Connecticut: Wallingford/Pierce (100 MW), Kleen Energy (560 MW summer/620 MW winter), Waterbury CT (80 MW summer/96 MW winter), DG Capital Grant projects (130 MW; 96 MW of which is counted on the supply side), long-term renewable energy contracts (150 MW), an expansion at Cos Cob (40 MW), and an uprate at Millstone 3 (81 MW).
- 279 MW of new combustion turbines to meet the fast-start requirement in Connecticut based on an analysis of the Local Forward Reserve Market (LFRM) requirements described in Appendix A. This figure was very close to the level reflected in a December 14, 2007 DPUC decision that derived 282 MW of fast-start resources.
- More than 700 MW of peak demand savings by 2011, and more than 1,000 MW of peak demand savings by 2018 from demand response (DR) and energy efficiency (EE) programs already underway or planned by the Companies. EE programs also reduce future energy requirements by 1,168 GWh by 2011 and 2,821 GWh by 2018.
- It was assumed that the rest of New England would also develop new DR and EE at half the rate Connecticut develops new DR and EE per megawatt of load.
- It was assumed that no existing Connecticut capacity would retire, based on a preliminary screening analysis, as discussed further in Appendix C.

Figure 2.1 shows all of these elements and calculates the "resource gap" as the difference between the ICR and the already-planned resources. As the figure shows, there is no gap in the Current Trends scenario in 2011 or 2013. By 2018, ISO-NE will need approximately 1,500 MW of new resources.

Figure 2.1 also shows the unplanned resources that would be added in 2018 and 2030 as part of the Nuclear solution. (Corresponding figures for the other scenarios and solutions are provided in Appendix A.) Note that the "Nuclear" solution is actually a hybrid resource solution (as are the Coal and DSM-Focus solutions, since they also incorporate additional gas-fired generation). It includes one 1,200 MW nuclear unit, assumed to be located in Connecticut, and gas-fired generation is added to meet the remaining resource gap.

Figure 2.3: Connecticut Planned DSM Shown as a Portion of Peak Load



This study evaluated the economic and other impacts of four types of resource solutions that differ in character and impact: "Conventional Gas Expansion," "Demand-Side Focus," "Nuclear," and "Coal," each of which is described below. It is important to note that all of these solutions contain a blend of generation technologies and significant amounts of DSM. All include at least the "reference" or "base" amount of DSM planned by the Companies, which provides a significant resource before additional resources are added. All resource solutions rely on gas-fired generation (primarily CCs) to meet any resource gap that remains after adding one 1,200 MW nuclear or coal plant or additional DSM measures.

i. Conventional Gas Expansion

The "Conventional Gas Expansion" solution uses only gas-fired combined-cycles (CCs) and combustion turbines (CTs) to meet the identified resource gap in each scenario.[6] The particular

[6] While we model gas-fired CCs and CTs, we recognize that such capacity could be dual-fuel capable with distillate oil back-up.

technology and location of each resource was selected based on economics. Primarily CCs were selected because their higher energy margins more than offset their higher capital costs and fixed operating and maintenance costs. CCs were assumed to be located primarily outside of Connecticut because the incremental energy margins appeared to be insufficient to offset the higher construction and operating costs in Connecticut than in the rest of New England. CCs in Connecticut were estimated to cost $869/kW, and CTs were assumed to cost $598/kW.[7] The three other solutions are similar to the Conventional solution, except that they replace 600-1,200 MW of CCs with alternative resources.

ii. DSM-Focus

Section 51(c) requires that "energy resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible." The DSM-Focus resource solution assumes the effectiveness of significantly higher amounts of DSM investments that (a) "aim higher/go deeper," *i.e.*, strive for the highest efficiency levels in end-use consumption that are cost-effective; (b) accelerate the retirement of inefficient customer systems; (c) integrate program design and delivery; and (d) integrate with other state-wide initiatives, such as the Climate Change Action Plan and the Governor's Energy Vision. The amount of DSM contemplated in this resource solution is unprecedented in New England.

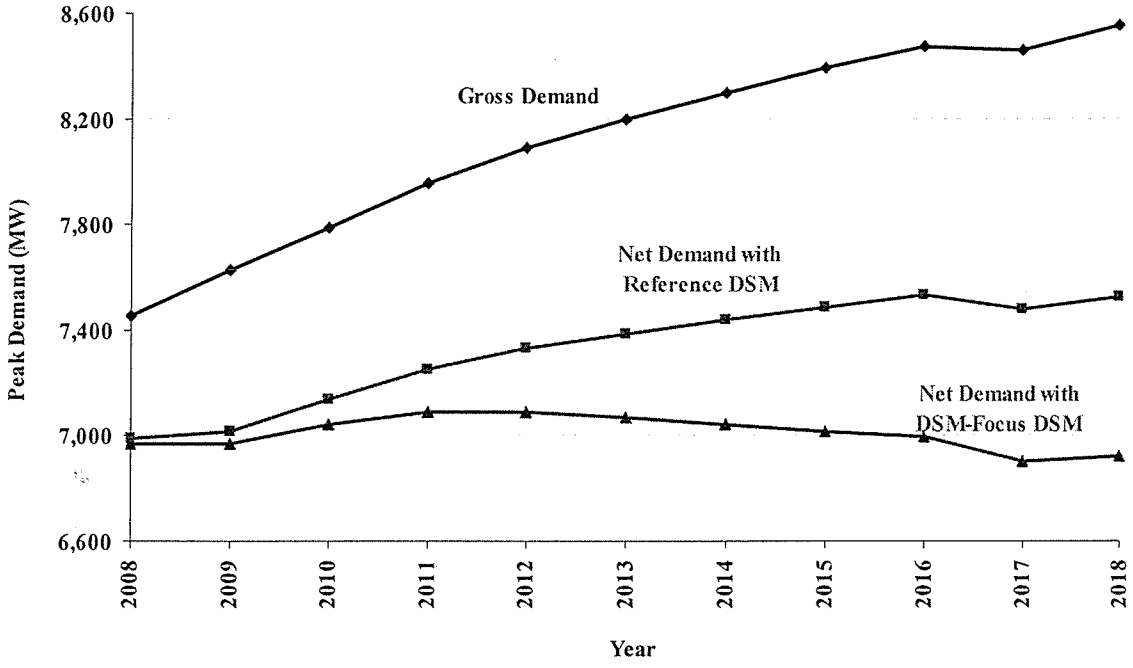
The DSM-Focus resource solution builds on successful, and aggressive existing DSM programs, *i.e.*, the "Reference Case DSM," that is assumed to be present in all scenarios and thereby implicit in other resource solutions. We use the existing and currently-planned level of DSM investment as the "Reference Case DSM" in all solutions except the DSM-Focus solutions. In the "DSM-Focus" resource solution, the existing DSM programs expand in several directions, enabled by substantially higher funding levels. By 2018, demand savings from the DSM-Focus scenario constitutes about 19.1% reduction of system peak.[8] While Reference DSM eliminates about 93% of potential load growth between 2008 and 2018, the DSM-Focus resource solution

[7] Other key characteristics for CCs and CTs include fixed O&M costs of $29.7 and $26.7, variable O&M costs of $1.4 and $3.2, and heat rates of 7,000 and 10,200, respectively. Real capital charge rates of 10.7% were applied to calculate annual capital carrying charges.

[8] Beyond 2018 savings from EE and DR programs were assumed to grow at the same rate as Connecticut system peak.

actually reduces demand to below current levels by 2018 in the Current Trends scenario, as shown on Figure 2.3.

Figure 2.4: CT Peak Demand (MW) Forecast under Different DSM Scenarios



Source: 2007-2016 CT Peak Demand (MW) data from ISONE spreadsheet titled "isone_2007_forecast_data.xls." 2007-2018 CT Peak Demand (MW) data based on *The Brattle Group* extrapolation of hourly ISONE data. DSM data for the Reference and DSM-Focus cases provided by the Companies.

iii. Nuclear and Coal Solutions

The purpose of the Nuclear and Coal solutions is to evaluate the addition of about 1,200 MW of high capital cost/low fuel cost baseload capacity in Connecticut, with different characteristics. The nuclear generation has very low fuel cost and emissions, but potentially very high capital cost, while coal units have somewhat higher fuel costs and lower capital costs than nuclear but significant CO_2 emissions. These resource solutions are designed to test an alternative to the conventional gas-fired CC and CT generating capacity expansion strategy. The first step to constructing these solutions was to perform a screening analysis to identify the most economic baseload technologies. This analysis is described in Appendix C. The screening analysis

indicated that nuclear and super-critical coal without carbon capture and sequestration had relatively favorable costs compared to other possible technologies.

The capital cost of nuclear is a major uncertainty that could have a major effect on its economics relative to coal, and so it is difficult to conclusively prefer one technology over the other. In addition, it should be noted that large baseload coal and nuclear plants have longer lead times than gas-fired combined cycle, and therefore represent a larger financial commitment over a longer period of time.

iv. Characteristics of Resource Solutions

The resource solutions in this study are evaluated primarily based on their expected cost and performance characteristics, such as efficiency and emissions. However, there are many attributes of resource solutions that are not well captured in such an analysis. For example, some resource solutions require more up-front commitment while others are more readily scaled up or scaled back in response to emerging market conditions. These attributes are summarized below. This includes certain risks of costs and operational performance, lead times, and the ability to scale investment commitments over time to respond to evolving market conditions. The following table characterizes the resource solutions along selected dimensions that are not analyzed quantitatively in this study.

Table 2.4: Other Factors Affecting Resource Solutions

	Conventional	DSM-Focus	Nuclear	Coal
Siting/Permitting Challenges	Med	Low	High	High
Capital Cost Uncertainty	Med	Low	Very High	High
Lead Time	Med	Low	Very High	High
Commitment/Scale Risk	Med	Low	Very High	High
Operational Performance Risk	Low	Med	Low	Low

E. Analysis of Solutions Using Market Models

The impact of each of the four resource solutions across all four scenarios is analyzed using structural models of the ISO-NE's energy and capacity markets. These markets, their recent performance, and how they are modeled in this study, are described in detail in Appendix A. This section of the report provides only a brief overview.

i. ISO-NE Energy Market Modeling

The ISO-NE administers day-ahead and real-time energy markets in which the lowest cost generation (based on bids and subject to transmission constraints and operating constraints) is dispatched to meet the demand on the system at each moment. These markets establish a market clearing price, which is the basis for settlement, *i.e.*, the amount that load serving entities pay and generators get paid for energy. The clearing price varies by node, reflecting the costs of transmission congestion and marginal losses when transmitting power between any two nodes.

Because there are transmission constraints and losses both into and within Connecticut, it is important to consider these factors and the broader ISO-NE energy market in an integrated resource plan for Connecticut. To do this, we have employed DAYZER, a state-of-the-art power market simulation model developed by Cambridge Energy Solutions (CES). The data inputs to DAYZER represent all of the elements of supply, demand, and transmission in the ISO-NE system and how these elements evolve over time depending on resource strategies.[9] Using these inputs, DAYZER simulates the ISO-NE's operation of the system and its administration of the energy market. The model outputs include hourly locational marginal prices, dispatch costs, generation, and emissions for every generating unit in New England, and transmission flows and congestion. These outputs are the basis for evaluating outcomes with one resource solution versus another.

In order to be consistent with the statute's requirement for three, five, and ten-year outlooks, it was necessary to simulate years 2011, 2013, and 2018. The year 2030 was also simulated in order to test the long-term implications of decisions made over the next ten years. The data inputs for these future years were developed in four steps.

[9] Data inputs are described in detail in Appendix G.

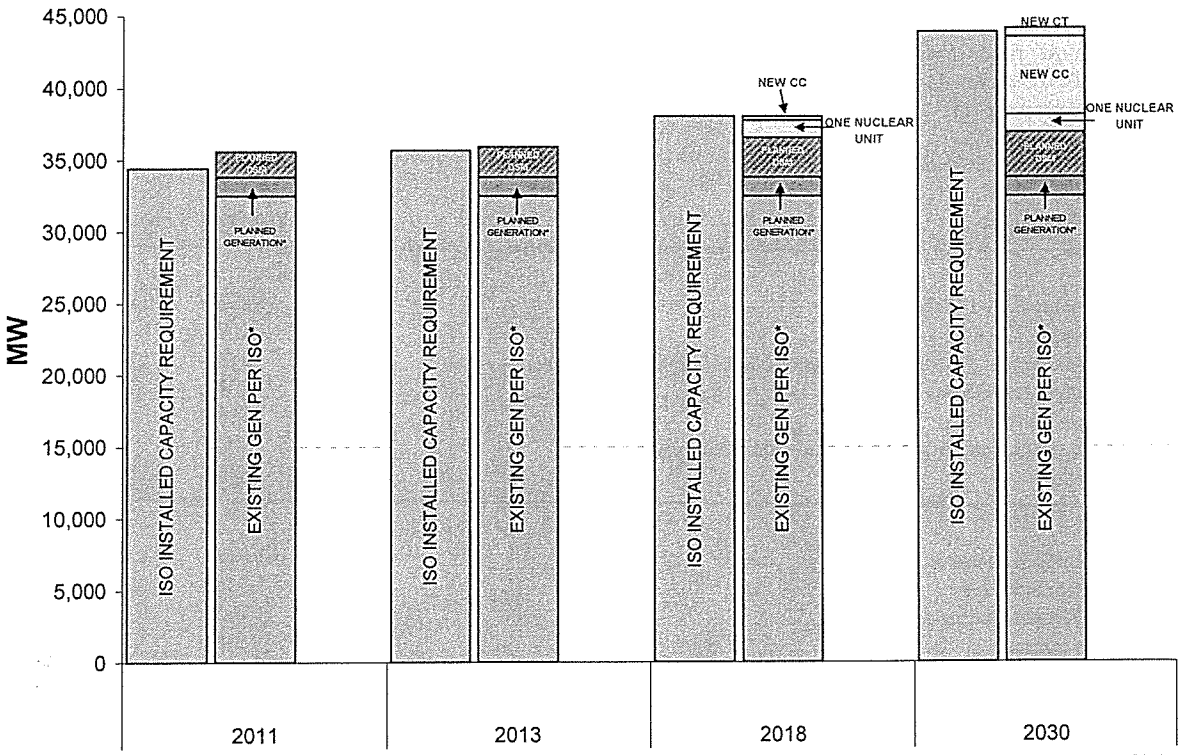
1. First, by developing an accurate representation of today's system. This involved representing every element of the current transmission system using a dataset from ISO-NE, auditing the load and generation inputs against ISO-NE sources, and reviewing data with the Companies to identify any errors or omissions.
2. Second, by projecting likely changes in fundamentals, including load growth, demand-side management, generation development and retirements, fuel and emission allowance prices, and transmission enhancement, based on current trends and plans (this becomes the "Current Trends" scenario).
3. Third, by adding sufficient unplanned resources to meet the ISO-NE's resource adequacy requirements for ISO-NE as a whole and for Connecticut specifically, as discussed in Section III. The types of unplanned resources vary by Solution: gas-fired combined cycle (CC) plants and combustion turbines (CT) in the Conventional resource solution, large-scale coal or nuclear plants in the Nuclear and Coal resource solutions, and additional demand-side management (DSM) programs in the DSM-Focus solution. Because these cases are otherwise identical, the differences in outcomes reflect only the differences in value among the various solutions tested.
4. Fourth, by varying the uncontrollable, exogenous factors of fuel and allowance prices and economic growth according to the Current Trends, High Fuel/Growth, Strict Climate, and Low Stress scenarios described above.

ii. ISO-NE Capacity Market Modeling

ISO-NE also administers a capacity market to facilitate a liquid, transparent mechanism for market participants to buy and sell capacity to meet their resource adequacy requirement. Capacity payments have been a significant cost component for load serving entities and are likely to become larger in the future as the current ISO-wide capacity surplus diminishes. More information will become available when the first forward capacity market (FRM) auction for 2010/11 delivery occurs in February, 2008.

In this study, it was assumed that the forward capacity price would be at the designated floor of $4.50/kw-mo in 2011, when there is substantial overcapacity in all scenarios (except Low Stress, which is at equilibrium). The capacity price was then projected to trend toward the net cost of

Figure 2.1: ISO-NE Supply-Demand Balance and Nuclear Resource Solution in Current Trends Scenario



*Existing generation includes imports, net purchases, and New Boston retirement. All planned generation includes Waterbury, Kleen, Additional LFRM Required CT, Wallingford/Pierce unit, DG Capital Grant Projects, Renewable Energy Contracts, Cos Cob expansion, and Millstone 3 uprate.

Each of the four scenarios analyzed depicts a different future evolution of the New England electricity market. As a result of using different underlying demand forecasts and adjusting for the impact of different fuel and electricity prices expected in the scenarios, the projected peak load levels will vary among the scenarios. Because the other adjustments described above are assumed fixed across scenarios, the magnitude of the expected "resource gap" will therefore vary. Table 2.2 shows how the projected resource gap evolves under each scenario in ISO-NE

As also seen in this table, the ISO-NE resource gap varies dramatically across scenarios. For example, the resource gap in 2018 varies from about 1,000 MW in the Strict Climate scenario (where high fuel and electricity prices depress load growth) to almost 4,500 in the Low Stress scenario (where generally lower fuel and electric prices lead to higher demand growth). The parameterization of the scenarios has captured a broad range of resource needs over the next decade, at least at the ISO-NE level.

Table 2.2: Resource Gap Relative to ISO-NE Installed Capacity Requirement (MW)

		2011	2013	2018	2030
GROSS LOAD BY SCENARIO	[1]				
ISO Base Case Peak Load		29,650	30,675	32,664	37,698
Current Trends Scenario		29,650	30,675	32,664	37,698
Strict Climate Scenario		29,239	30,158	31,871	36,784
High Fuel/Growth Scenario		29,429	30,699	33,391	38,538
Low Stress Scenario		30,692	32,135	35,247	40,680
Reserve Requirement		16.2%	16.5%	16.6%	16.6%
SUPPLY					
2008 Internal Installed Capacity	[2]	30,855	30,855	30,855	30,855
Planned Capacity Additions	[3]	1,107	1,107	1,107	1,107
Assumed Addition of Fast-Start Capacity to Meet LFRM Requirement	[4]	279	279	279	279
Existing Purchases & Sales	[5]	291	291	291	291
Hydro Quebec Imports	[6]	1,400	1,400	1,400	1,400
Adjustment for Planned Additions Already Included in [2]	[7]	(85)	(85)	(85)	(85)
Planned Supply	[8]	33,847	33,847	33,847	33,847
DSM	[9]				
Current Trends Scenario		1,534	1,812	2,355	2,704
Strict Climate Scenario		1,328	1,554	1,959	2,247
High Fuel/Growth Scenario		1,004	1,165	1,456	1,668
Low Stress Scenario		1,534	1,812	2,355	2,704
SHORTFALL (SURPLUS)					
Current Trends Scenario		(1,163)	(225)	1,492	6,957
Strict Climate Scenario		(1,402)	(525)	1,030	6,423
High Fuel/Growth Scenario		(805)	557	3,389	9,144
Low Stress Scenario		48	1,476	4,504	10,433

Sources and Notes:

[1]: Grossed up for DSM.

[2]: 2007 *CELT* report; reduced by 350 MW per ISO to reflect New Boston unit retirement.

[3]: Includes Wallingford/Pierce (100 MW), Kleen Energy (560 MW summer/620 MW winter), Waterbury CT (80 MW summer/96 MW winter), DG Capital Grant projects (130 MW; 96 MW of which is counted on the supply side), long-term renewable energy contracts (150 MW), an expansion at Cos Cob (40 MW), and an uprate at Millstone 3 (81 MW).

[4]: Assumed addition of fast-start capacity to meet Connecticut LFRM requirement.

[5]-[7]: 2007 *CELT* report.

[8]: [2]+[3]+[4]+[5]+[6]+[7].

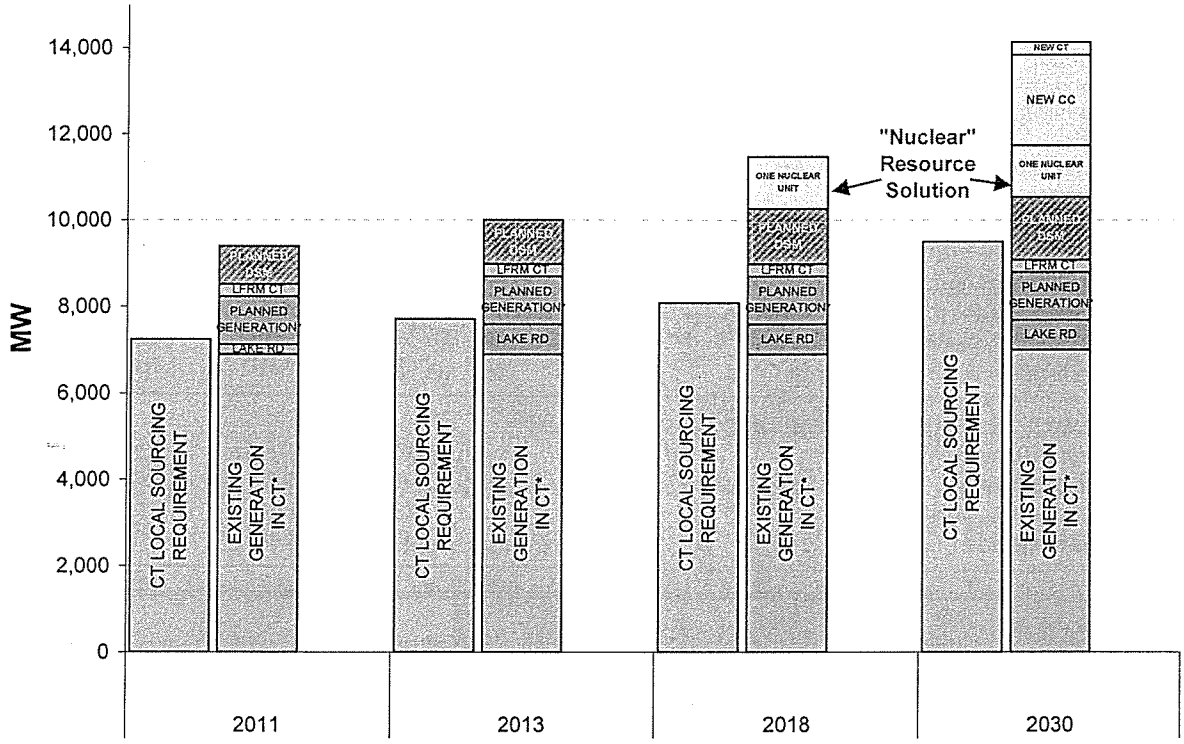
[9]: Grossed up by a factor of 1.08 for transmission and distribution losses.

ii. Connecticut Local Sourcing Requirement

ISO-NE also imposes local sourcing requirements (LSR) for Connecticut and Boston to ensure that the target LOLE is achieved in these load centers. However, Figure 2.2 shows that there will be no resource gap through 2030 under the Nuclear resource solution – due primarily in the early years (2011 and 2013) to planned generating additions and aggressive DSM measures – and Table 2.3 shows that none of the scenarios have a resource gap with respect to the local sourcing

requirement.[4] The candidate resource solutions that add capacity within Connecticut do so for reasons other than the LSR, *i.e.*, to meet the ISO-NE installed requirement and to affect Connecticut's policy objectives regarding cost, environmental emissions, and fuel diversity.

Figure 2.2: Connecticut Supply-Demand Balance and Nuclear Resource Solution in Current Trends Scenario



*Existing generation is net of sales. Other planned generation includes Waterbury, Kleen, Wallingford/Pierce unit, DG Capital Grant Projects, Renewable Energy Contracts, Cos Cob expansion, and Millstone 3 uprate.

[4] ISO-NE has determined the LSR corresponding to the load forecast that is used in the Current Trends scenario. The LSR corresponding to the other scenarios, with their different load forecasts, was estimated based on the relationship between the LSR and load growth implicit in ISO-NE's requirements for 2010 and 2016: for every megawatt of load growth in Connecticut, the LSR increases by 1.26 MW.

Table 2.3: Resource Gap Relative to Connecticut Local Sourcing Requirement (MW)

		2011	2013	2018	2030
LOCAL SOURCING REQUIREMENT IN CONNECTICUT					
Current Trends Scenario		7,251	7,718	8,086	9,506
Strict Climate Scenario		7,114	7,546	7,824	9,210
High Fuel/Growth Scenario		7,177	7,726	8,326	9,778
Low Stress Scenario		7,599	8,204	8,938	10,471
SUPPLY					
2008 Internal Installed Capacity	[1]	6,999	6,999	6,999	6,999
Inclusion of Lake Road Units in Connecticut	[2]	233	699	699	699
Additional Planned Capacity	[3]	1,107	1,107	1,107	1,107
LFRM CT	[4]	279	279	279	279
Purchases & Sales	[5]	(100)	(100)	(100)	-
Internal Gen Capacity	[6]	8,518	8,984	8,984	9,084
DSM	[7]				
Current Trends Scenario		763	881	1,108	1,255
Strict Climate Scenario		709	813	1,005	1,137
High Fuel/Growth Scenario		619	700	833	943
Low Stress Scenario		763	881	1,108	1,255
CONNECTICUT LSR SHORTFALL (SURPLUS)	[8]				
Current Trends Scenario		(2,229)	(2,376)	(2,295)	(1,159)
Strict Climate Scenario		(2,297)	(2,462)	(2,426)	(1,307)
High Fuel/Growth Scenario		(2,120)	(2,140)	(1,708)	(494)
Low Stress Scenario		(1,881)	(1,890)	(1,443)	(194)

Sources and Notes:

[1]: 2007 *CELT* report; Excludes Lake Road units which are physically in Connecticut but electrically in Rhode Island.

[2]: In 2011, one Lake Road unit (233 MW) is electrically transferred to Connecticut via an elective transmission upgrade by Lake Road. In 2013, the remaining two Lake Road units (466 MW) are electrically transferred to Connecticut via the NEEWS transmission project. We conservatively did not account for any additional increase in import capability associated with NEEWS in this analysis of resource adequacy.

[3]: Includes Wallingford/Pierce (100 MW), Kleen Energy (560 MW summer/620 MW winter), Waterbury CT (80 MW summer/96 MW winter), DG Capital Grant projects (130 MW; 96 MW of which is counted on the supply side), long-term renewable energy contracts (150 MW), an expansion at Cos Cob (40 MW), and an uprate at Millstone 3 (81 MW).

[4]: Assumed addition of fast-start capacity to meet Connecticut LFRM requirement.

[5]: 2007 *CELT* report. Accounts for a 100 MW capacity contract with Long Island across the Cross-Sound Cable.

[6]: [1]+[2]+[3]+[4]+[5].

[7]: Grossed up by a factor of 1.08 for transmission and distribution losses.

[8]: DSM is grossed up by 0.26 for consistency with the Local Sourcing Requirement.

It is important to note that the projected LSR surplus under the Current Trends scenario is very different than the Connecticut Resource Balance presented in the recent Connecticut Siting Council (CSC) report.[5] However, the potential resource needs identified in that report were

[5] See *Review of the Ten Year Forecast of Connecticut Electric Loads and Resources 2007-2016*, Connecticut Siting Council, November 14, 2007, Table 3, page 13.

based on the ISO-NE "90/10" forecast (*e.g.*, the peak loads that the ISO would expect would be exceeded only 10% of the time) rather than the normalized forecast distribution used in the LSR determination, and the CSC evaluation also provides for the potential retirement of 1,600 MW of oil-fired capacity in 2011 and 2,000 MW in 2013, as a consequence of capacity reaching 40 years in service. In addition, the CSC accounts for two plants that have been approved (Meriden & Oxford) but not constructed, for a total of about 1,050 MW additions. Perhaps most importantly, however, is the fact that the assumed level of DSM in Connecticut (based on the Companies' current plans) is quite substantial in all scenarios – even before considering the "DSM-Focus" resource solution. These assumptions are different than the expectations that govern our "Current Trends" scenario (see Appendix A for additional information).

D. Resource Solutions

Resource solutions refer to investments that market participants or the Companies could make in supply or demand-side resources, and/or transmission capability. Potential solutions differ in composition, but this study assumes that they do not differ in the quantity of resources that would be added. All solutions just fill the resource gaps discussed in Section III. To assume less would imply an expectation that planners would fail to maintain a reliable system and/or that market participants would overlook opportunities to earn more than their cost of capital (the forward capacity market would theoretically clear above the net cost of new entry if there were a shortage). To assume more would imply that planners build more capacity than is needed and/or that market participants would make investments that earn less than their cost of capital (the forward capacity market would theoretically clear below net cost of new entry if there were a surplus). This analytical construct does not imply that imbalances in the form of capacity deficiencies or surpluses cannot occur, but simply acknowledges the tendency for markets to trend toward equilibrium over time, and that it is not possible to predict when transient imbalances might actually occur.

One of the challenges of evaluating resource solutions in the context of a deregulated generation market such as ISO-NE is the extent to which cost-of-service based investments or contracts might complement or compete with investments made by third parties such as unaffiliated

generation companies. At this stage, we do not distinguish between generation investments made by other market participants and those that may be made by the Companies on a cost-of-service basis (we do assume that the demand-side resource solution is pursued by the Companies). In all resource solutions/scenarios there are assumed generation investments made in other parts of ISO-NE between 2008 and 2018. In some resource solution/scenario combinations additional generation is also built in Connecticut as needed to maintain reliability criteria and/or that reflects economic new entry. Thus, all of the resource solutions examined here represent a blend of supply and demand-side resources that could emerge in the market; the specific resource solutions examined here essentially emphasize particular approaches.

The Companies' "Base" or "Reference" level of planned DSM included in all solutions is aggressive and has a significant impact on Connecticut load and energy. The planned DSM reduces total Connecticut energy by 1,168 GWh by 2011 and 2,821 GWh by 2018, and cuts Connecticut peak load by approximately 10% in 2010. Figure 2.3 shows the impact of planned DSM in the Current Trends Scenario. These programs are expected to cost approximately $120 million per year by 2009 (in 2008 dollars) and stay at that level in real terms for 10 years.

new entry (Net CONE) in the first year in which the market came into supply/demand equilibrium. Net CONE is given by the capital carrying cost plus annual fixed O&M costs minus the energy margins of new units.

As described in greater detail in Appendix A, we have projected capacity prices generally below the initial floor, due to the projected energy margins for CCs, which are much higher than for CTs (which are only slightly less expensive to build) on which the initial floor was based.

F. Evaluation Metrics

After resource solutions are tested in DAYZER and other offline analyses, they are compared to each other using multiple evaluation metrics that correspond to the objectives outlined in PA 07-242 and also reflect the CEAB Preferential Criteria for the Evaluation of Energy Proposals. These metrics measure economic impacts such as resource costs and customer costs under various assumed pricing regimes; and also include reliability indices, environmental impacts, fuel diversity and energy security considerations. These metrics represent key indicators of the multi-attribute benefits and costs associated with each resource solution, and their values under each scenario help illuminate tradeoffs among the objectives and the expected benefits and risks of pursuing specific investments. These metrics include:

- **Total Going Forward Resource Cost** – a measure of the total value of resources consumed in meeting Connecticut loads.
- **Market Cost of Generation** – a measure of the costs that the Companies bear in serving their retail customers under existing short-term procurement rules and ISO-NE market prices.
- **Cost of Service Generation** – a measure of how the costs of generation would be reflected in Connecticut customers' bills under a hypothetical return to traditional cost-of-service pricing principles.
- **Reserve Margins and Load Factor** – measure the degree to which supply resources exceed demands and the relationship between peak load and average load.

- **Fuel Diversity and Security** – measures of the contribution of power generation to overall gas demand and particularly wintertime peak gas demands.
- **Environmental Outcomes** – measures of generation emissions and degree of compliance with RGGI CO_2 targets and renewable generation goals.

These measures are explained further in Appendix H.

SECTION III: FINDINGS

This section presents the analytical results, with a sub-section and graphs for each evaluation metric described in the previous section (and in more detail in Appendix H). Key conclusions that can be drawn from the analysis are discussed in the final sub-section.

A. Evaluation Metric Results

i. Total Going-Forward Resource Cost

Total Going-Forward Resource Cost includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, the costs of energy and capacity imports into Connecticut (at market prices), and DSM program costs. DSM costs for energy efficiency programs are capitalized over 10 years to reflect an average life of efficiency investments; this treatment differs from that in the Customer Cost metrics, where energy efficiency program costs are expensed in the year incurred in order to be consistent with current ratemaking practices.

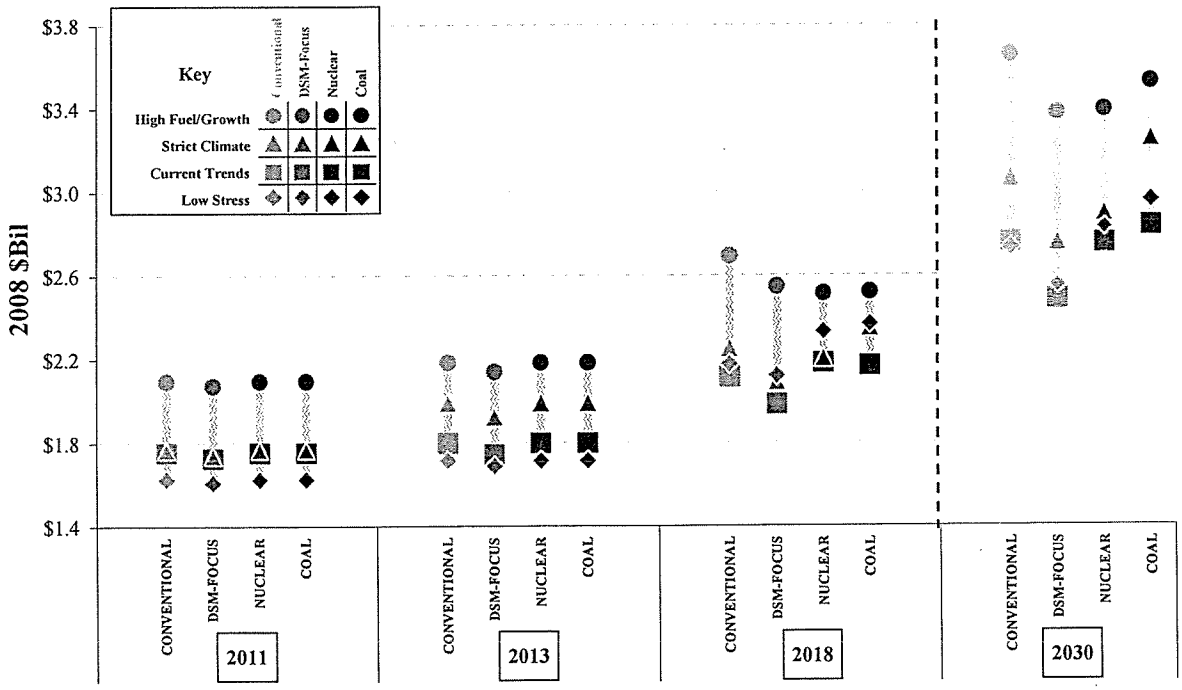
Figure 3.1 shows the total annual going-forward resource cost for each resource solution (shown as vertical lines, with color-coded markers) across each scenario (shown as markers on each vertical line) for each year. This figure, and similar figures that follow, makes it possible to compare resource solutions to each other and to see how cost/performance changes over time and as external factors vary.

Some key observations about Figure 3.1 are:

- Costs increase over time, driven by load growth and CO_2 allowance costs.
- Costs in any given year vary more by scenario than by resource solution. For example, costs are highest in the High Fuel/Growth scenario due to a 70% increase in gas prices compared to the Current Trends scenario.
- The costs of various resource solutions are indistinguishable in the initial years because the resource solutions do not yet differ significantly: baseload plants are not online until after 2013, and the additional DSM in the DSM-Focus solution has not yet ramped up to a level that is much higher than in the other resource solutions.

- In 2018 and 2030, the DSM-Focus resource solution has the lowest costs in every scenario except High Fuel/Growth, in which prices are high enough to induce much natural load reductions, reducing the incremental effectiveness of DSM programs. DSM-Focus is a close second in this scenario.

Figure 3.1: Total Going-Forward Resource Cost (Annual)



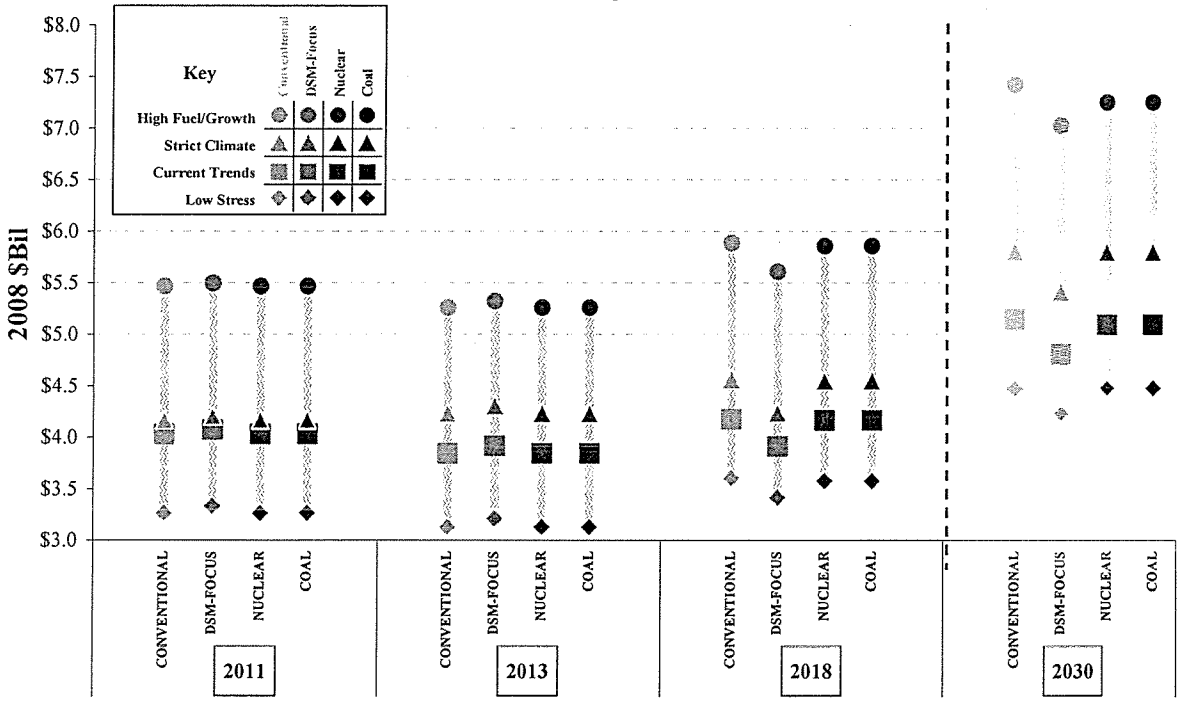
*Total Resource Cost includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs. Note that DSM costs for energy efficiency programs are capitalized over 10 years here; this treatment differs from that in the Customer Cost graphics, where energy efficiency program costs are expensed in the year incurred.

ii. Customer Costs

Total Customer Cost in the Market Regime includes load at LMP, capacity, revenues from financial transmission rights, an adjustment for losses, spinning reserve costs, uplift costs, the cost of the forward reserve requirement, DSM program costs (expensed, not capitalized), RPS costs, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service. Figure 3.2 shows the Total Customer Cost in the market regime following the same format as Figure 3.1. Some key observations about Figure 3.2 that differ from Figure 3.1 are:

- Even more than the Total Resource Cost, market-based Customer Costs vary substantially based on scenario drivers, especially the price of gas and the level of demand.
- The DSM-Focus solution has slightly higher costs in 2011 and 2013 because the cost of energy efficiency programs are expensed instead of capitalized. However, by 2018, substantial energy efficiency has accumulated in addition to demand response, resulting in energy and capacity savings that significantly outweigh ongoing program costs (relative to other resource solutions) in every scenario.

Figure 3.2: Total Customer Cost in Market Regime (Annual)

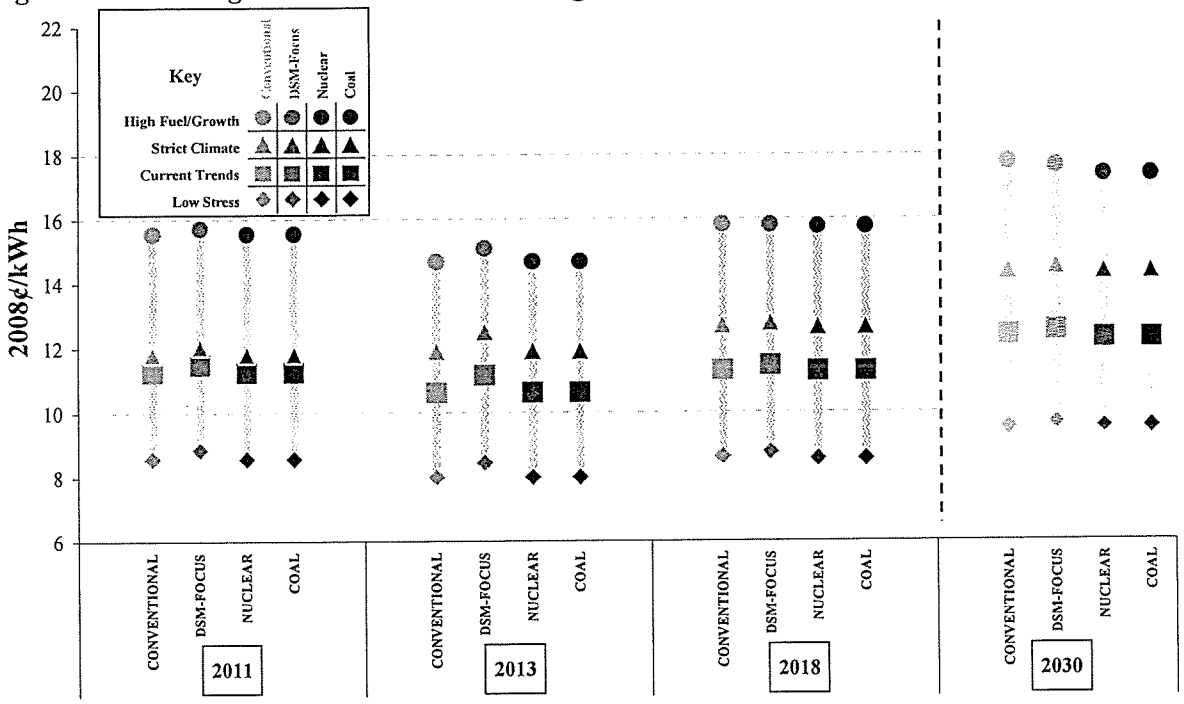


*Total Customer Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Figure 3.3 shows Customers' Average Unit Costs in the market regime, given by the annual customer cost divided by the annual energy requirement to serve Connecticut load. (This is not equivalent to the rate for any particular customer class, which will depend on future ratemaking decisions regarding incidence of DSM costs, etc.) Some observations that differ from the previous figures are:

- The various resource solutions have almost no impact on the unit cost since they do not change the fact that gas-fired resources set the market price.
- The cost-savings available from DSM, due to the reduction in volume consumed, is not apparent from unit costs. Hence, unit costs by themselves may not be as useful an indicator as total customer costs.

Figure 3.3: Average Unit Cost in Market Regime



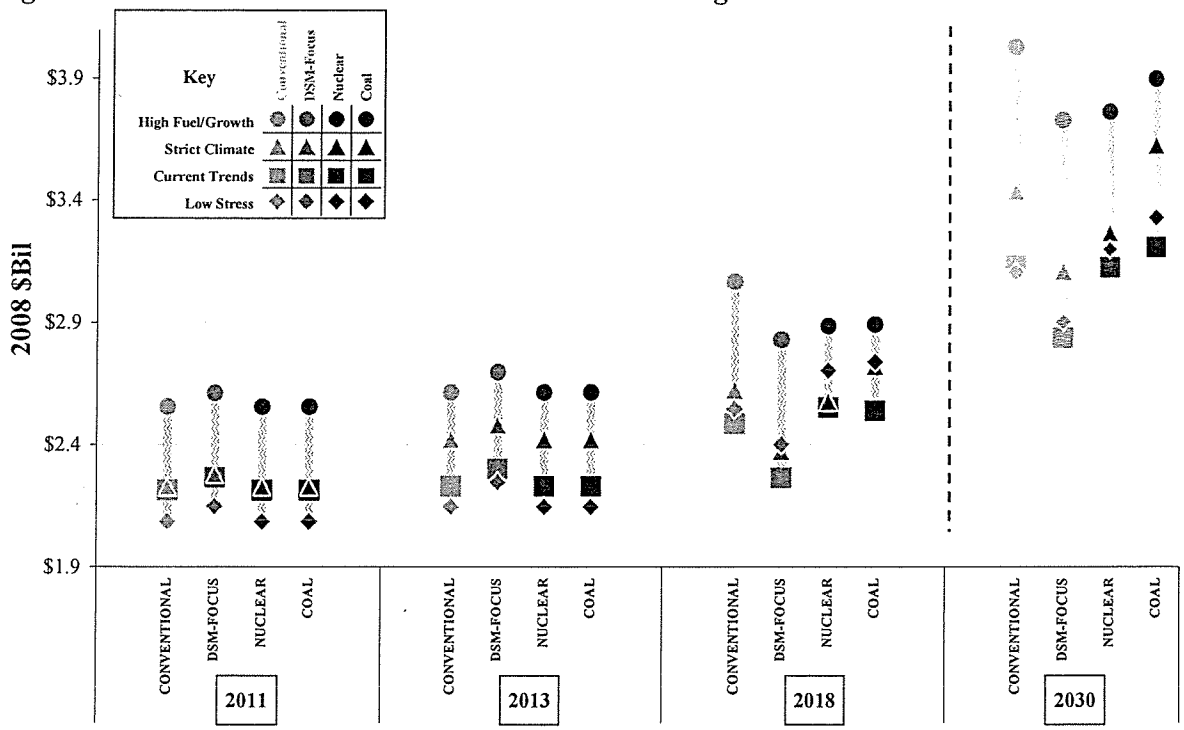
*Average Unit Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Total Customer Cost in Cost-of-Service Regime is similar to the Total Resource Cost shown in Figure 3.1 plus a hypothetical "embedded cost" of existing generation, and DSM costs are expensed instead of capitalized. Figure 3.4 shows Customer Costs in the hypothetical cost-of-service regime. Some of the key observations that differ from the previous metrics are:

- Customer costs vary much less than in the market regime because the cost of non-gas-fired generation is fixed as gas prices fluctuate.

- As in the market-based regime, customer costs appear higher initially in the DSM-Focus resource solution if the increased energy efficiency costs are expensed rather than capitalized during the ramp-up/investment period. By 2018, DSM-Focus has the lowest customer cost in every scenario.

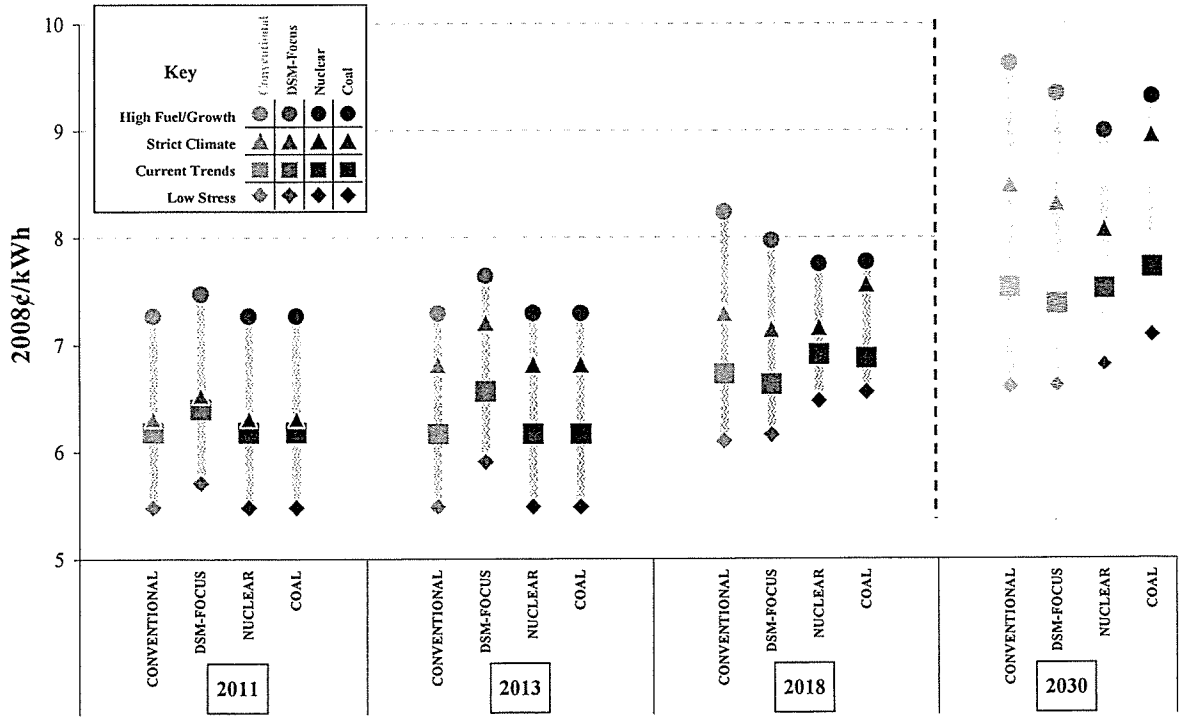
Figure 3.4: Total Customer Cost in Cost-of-Service Regime



*Total Customer Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figure 3.5 shows the Customers' Average Unit Costs in the cost-of-service regime, given by the annual customer cost divided by the annual energy requirement to serve Connecticut load. Some salient observations are that, again, unit costs are more stable with respect to scenarios than in the market-based regime, and unit costs are not a good indicator of the value of increased DSM.

Figure 3.5: Average Unit Cost in Cost-of-Service Regime



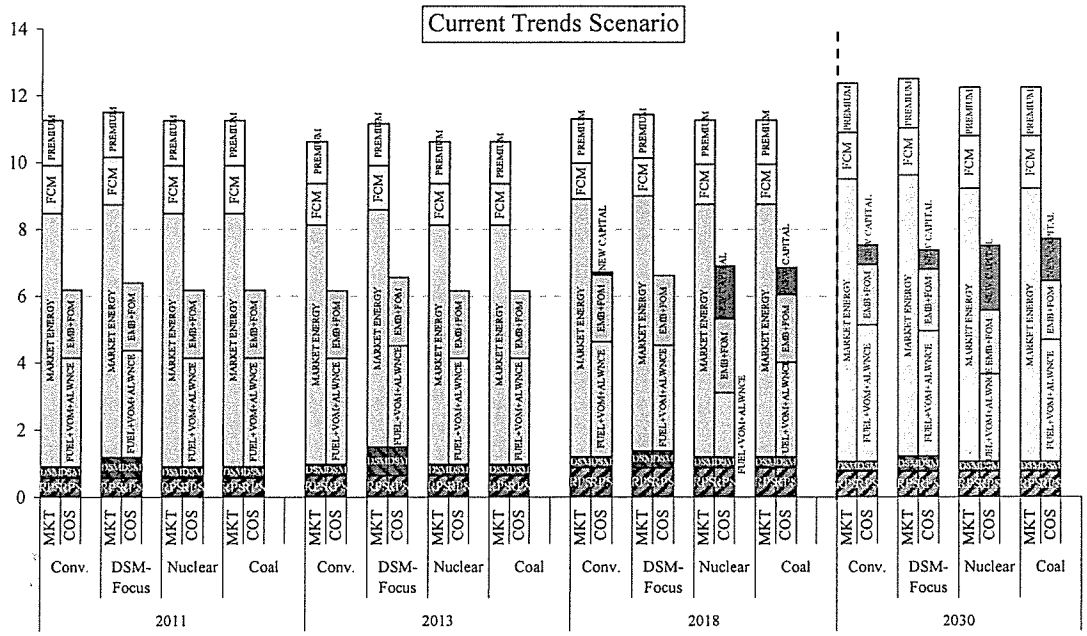
*Average Unit Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figures 3.6-9 show the components of customer costs under both regimes. Some salient observations are:

- Unit cost projections are lower in the cost-of-service regime because the costs were derived under a hypothetical cost of service regime for all in-State generation, with embedded costs in the cost-of-service regime based on historical book values, known Reliability Must-Run contract costs and asset sales prices. This computation is intended to illustrate qualitative differences between regimes, not to imply that the computed cost-of-service rate can actually be fully realized.
- Energy costs are the largest component of the market-based cost, reflecting wholesale electricity prices that are set largely by (high) natural gas prices. This component is much larger than the corresponding fuel + variable O&M and allowance costs under the cost-of-service regime.

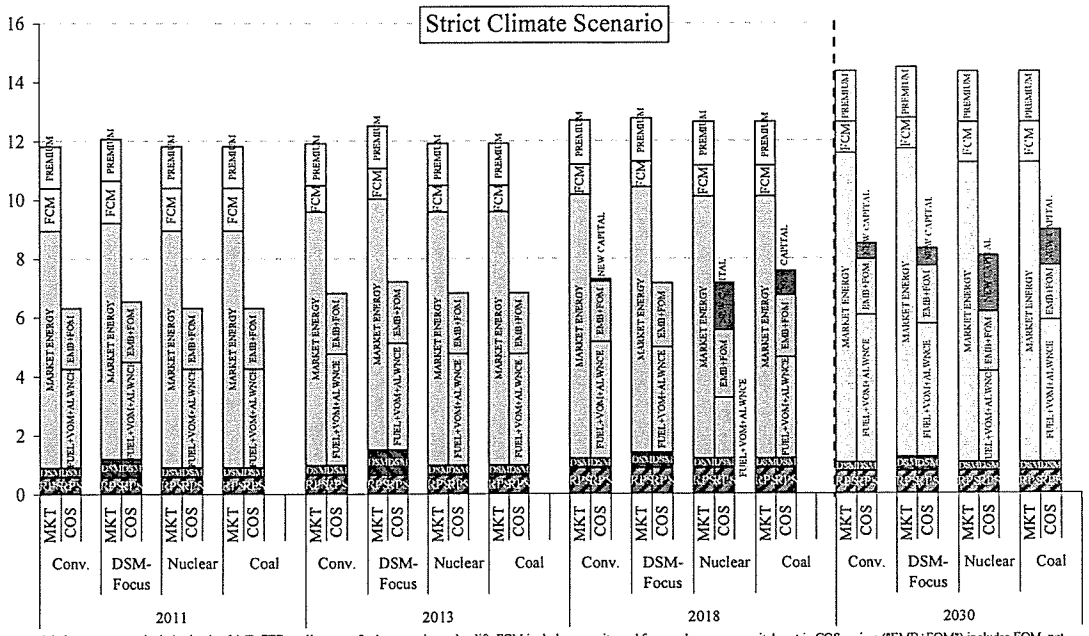
- Across scenarios, the energy cost varies much more in the market-based regime reflecting customers' exposure to gas prices.

Figure 3.6: Average Customer Cost Components (¢/kWh)



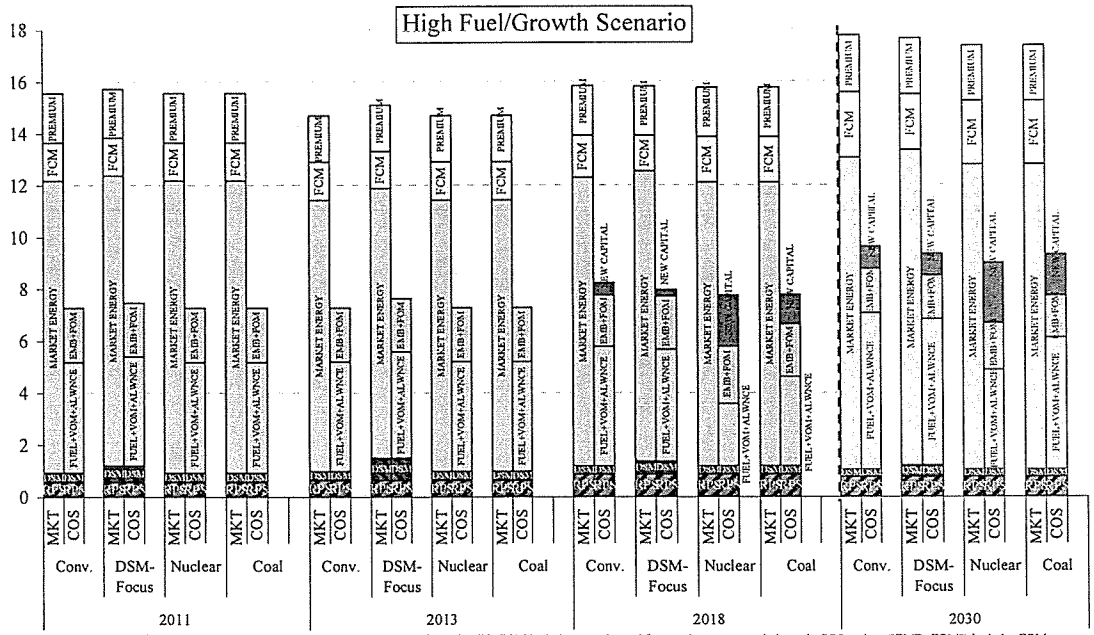
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure 3.7: Average Customer Cost Components (¢/kWh)



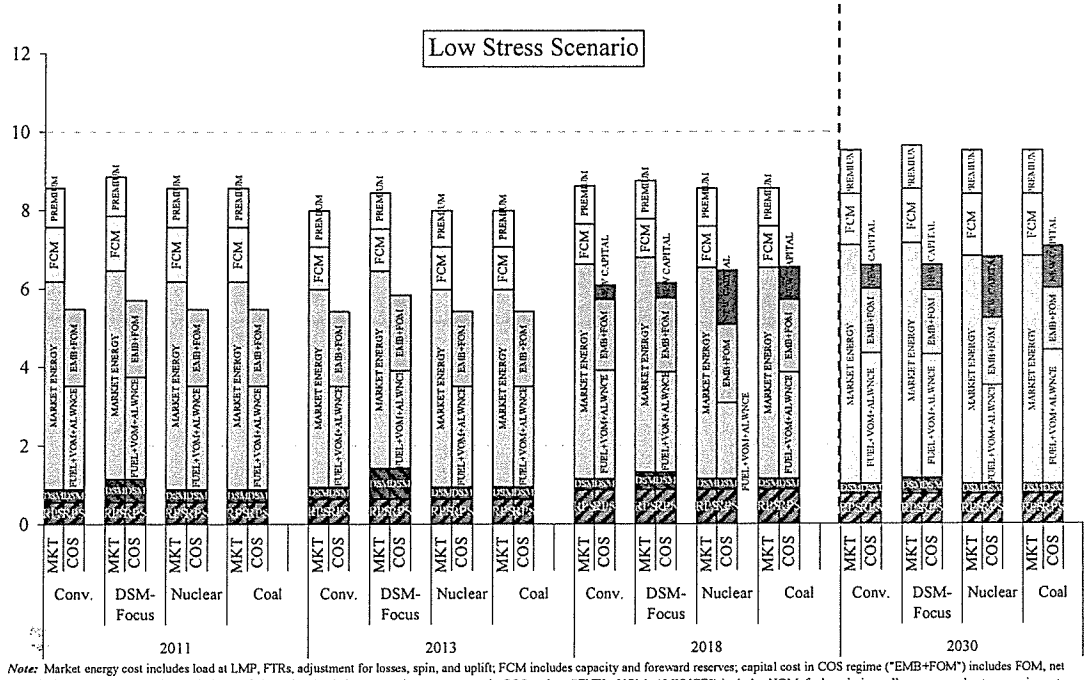
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure 3.8: Average Customer Cost Components (¢/kWh)



Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure 3.9: Average Customer Cost Components (¢/kWh)



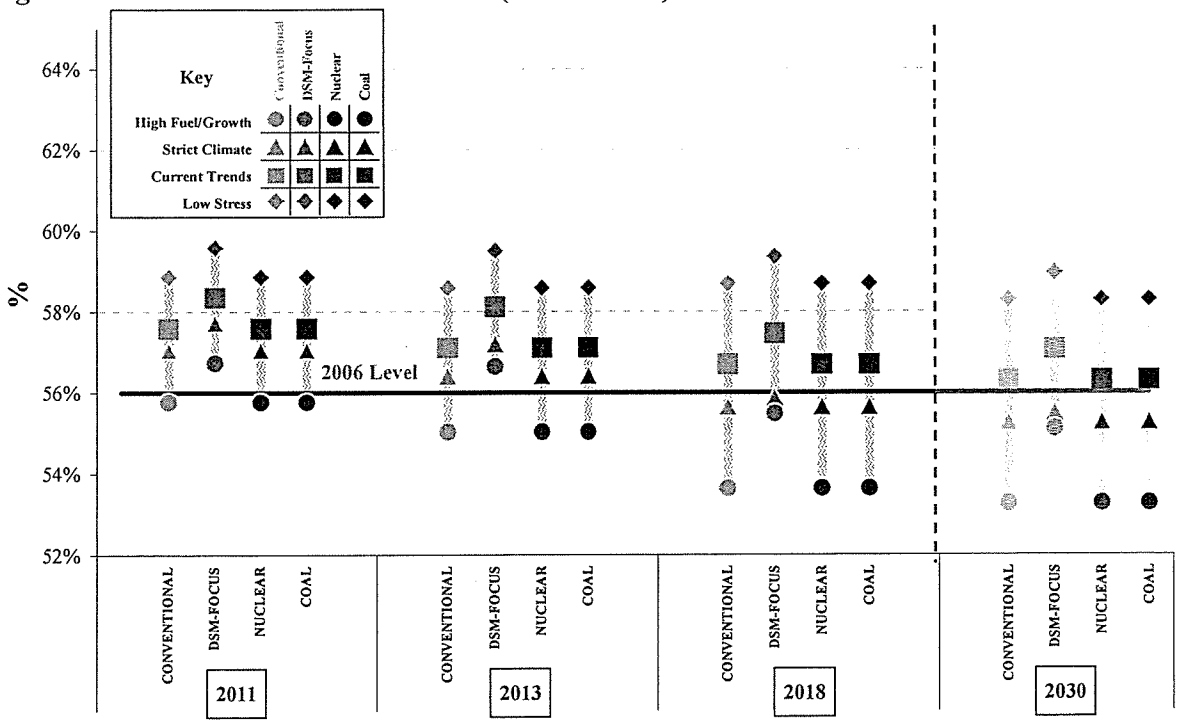
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

iii. Connecticut Load Factors

Figure 3.10 shows the projected load factor for Connecticut under each scenario and resource solution, net of DSM. Key observations are:

- Load factors are projected to improve relative to today then deteriorate from 2011 onward.
- This pattern is driven by the load forecast, the effect of DSM (demand response, which reduces peaks, is assumed to be implemented more rapidly than efficiency), and the differential effect of prices on peak vs. average consumption assumed in the scenarios.

Figure 3.10: Connecticut Load Factor (Net of DSM)



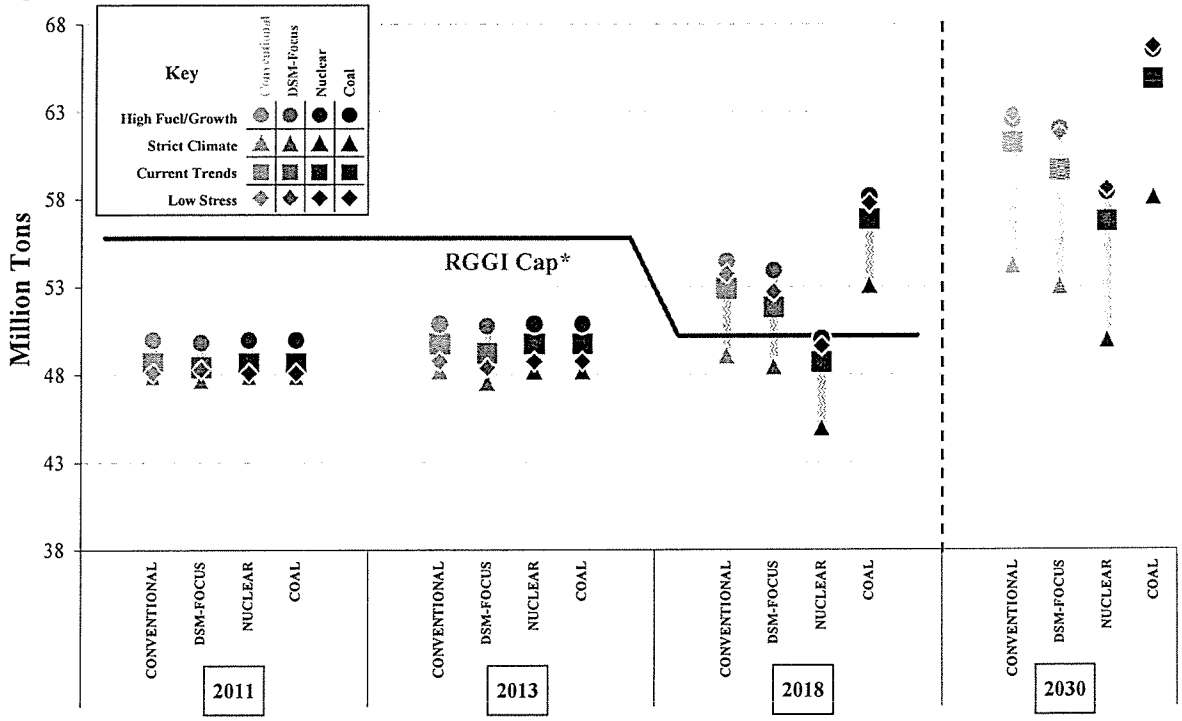
iv. CO_2 Emissions

Figure 3.11 shows power sector CO_2 emissions and the RGGI cap for only the six RGGI states that are located in ISO-NE. A surplus or deficiency does not indicate whole RGGI-region status. Key observations are:

- CO_2 emissions are expected to increase as load grows, except possibly in the Nuclear resource solution (adding more than one nuclear unit would reduce CO_2 emission further).
- Adding even a single coal unit raises emissions substantially above New England's share of the RGGI cap. However, the RGGI cap is indicative only; in our scenarios (and likely in reality) RGGI will be superseded by federal climate legislation in later years.
- Increased DSM reduces CO_2 emissions slightly.
- CO_2 emissions could be higher than indicated here under the following conditions:
    - If nuclear availability is the same as the average of 2001-06 (instead of being similar to 2006, the best historic year) CO_2 emissions could increase by 2 million tons, assuming a 3.4 TWh reduction in generation replaced by gas with an 8000 heat rate and 120 lb/MMBtu CO_2.

- If hydro output is equal to the average output of 2001-06, CO_2 emission could increase by approximately 1 million tons, assume 1.8 TWh reduction in generation replaced by gas.
- If imports are less than the 13 TWh assumed, CO_2 emissions could increase substantially.

Figure 3.11: CO_2 Emissions in ISO-NE



*Emissions and RGGI cap shown here reflect the 6 member states of ISO-NE only. A surplus or deficiency does not indicate whole RGGI-region status.

v. Gas Usage and Fuel Diversity

Figures 3.12-17 show gas usage in Connecticut and New England. Key observations are:

- Gas usage will increase in virtually all cases, due to load growth.
- Gas usage increases markedly in low stress, because low gas prices cause low power prices and higher load growth. In the extreme, there is likely to be feedback that limits further load growth if gas supply becomes problematic (higher gas prices will limit further load growth). However, this feedback may not prevent the problem from occurring, but would likely occur only after gas supply problems materialize.

- A baseload resource solution (coal or nuclear) limits the growth in gas usage, though does not eliminate it entirely, particularly in the Low Stress scenario. This is caused by the large amount of gas fired capacity added after 2018 in all cases as a result of the screening analysis.
- Gas share of generation is less important than the actual quantity of gas used (for all purposes), in terms of gas deliverability and customer effects.
- The total quantity of gas used for all purposes is especially important during periods of peak gas demand, *e.g.*, winter.

Figure 3.12: Winter (January - February) Power Sector Gas Use in Connecticut

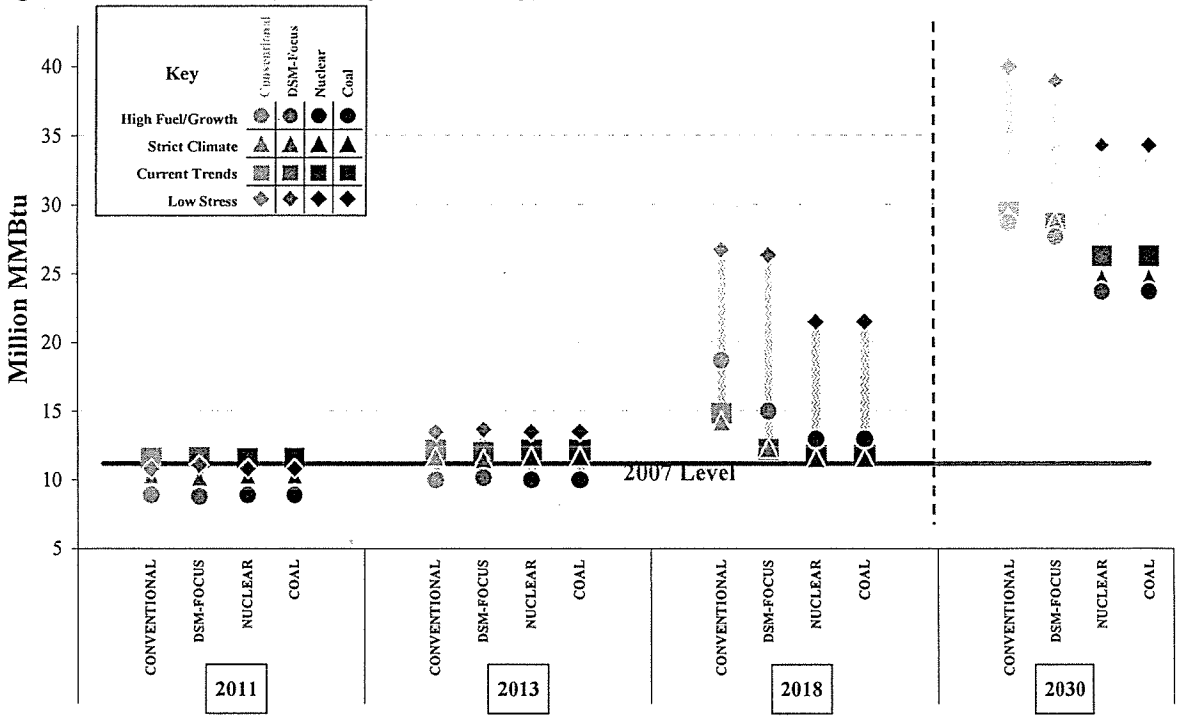


Figure 3.13: Winter (January - February) Power Sector Gas Use in ISO-NE

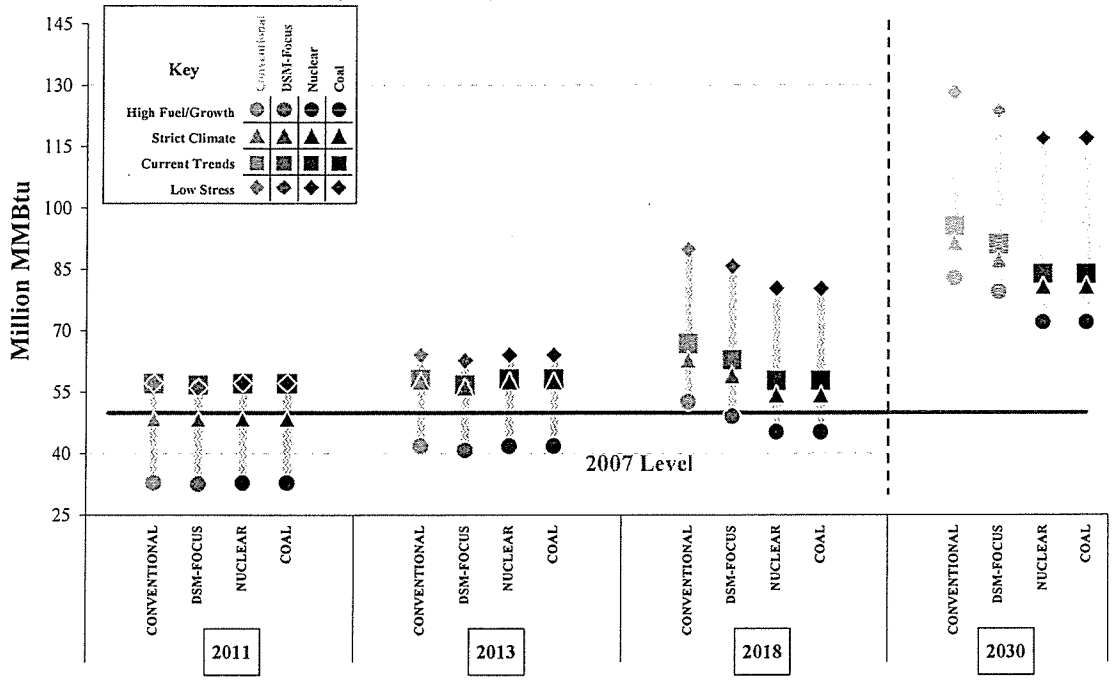


Figure 3.14: Connecticut Gas-fired Generation Share of Total Generation

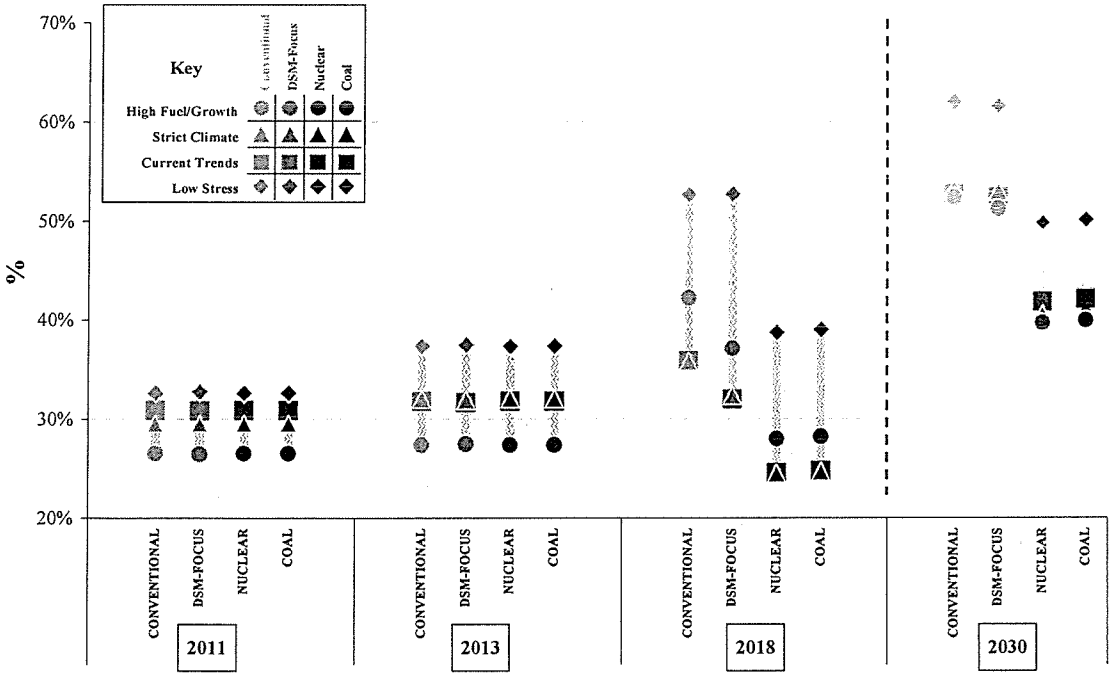


Figure 3.15: ISO-NE Gas-fired Generation Share of Total Generation

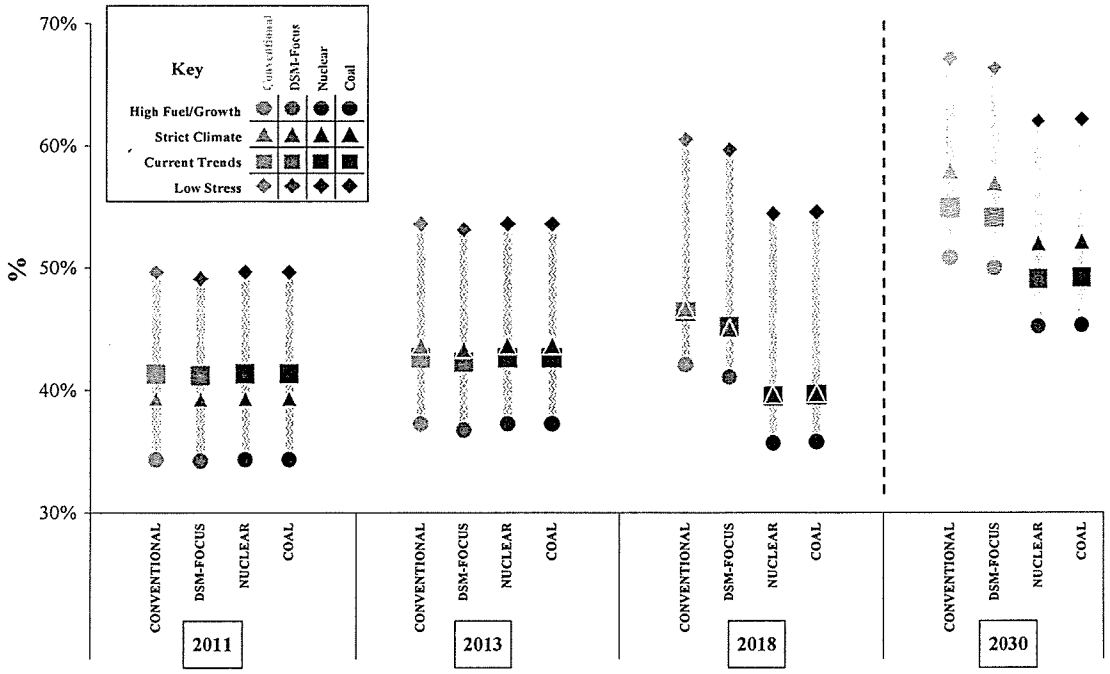


Figure 3.16: Connecticut Fuel Mix (Cumulative Generation in TWh)

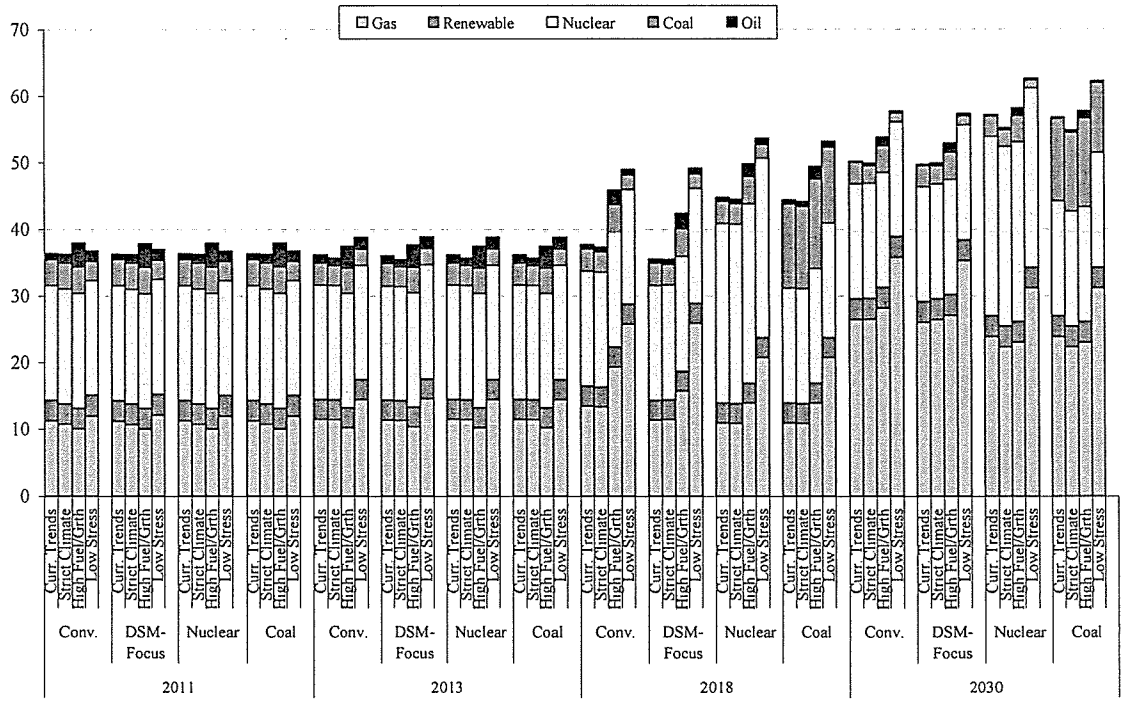
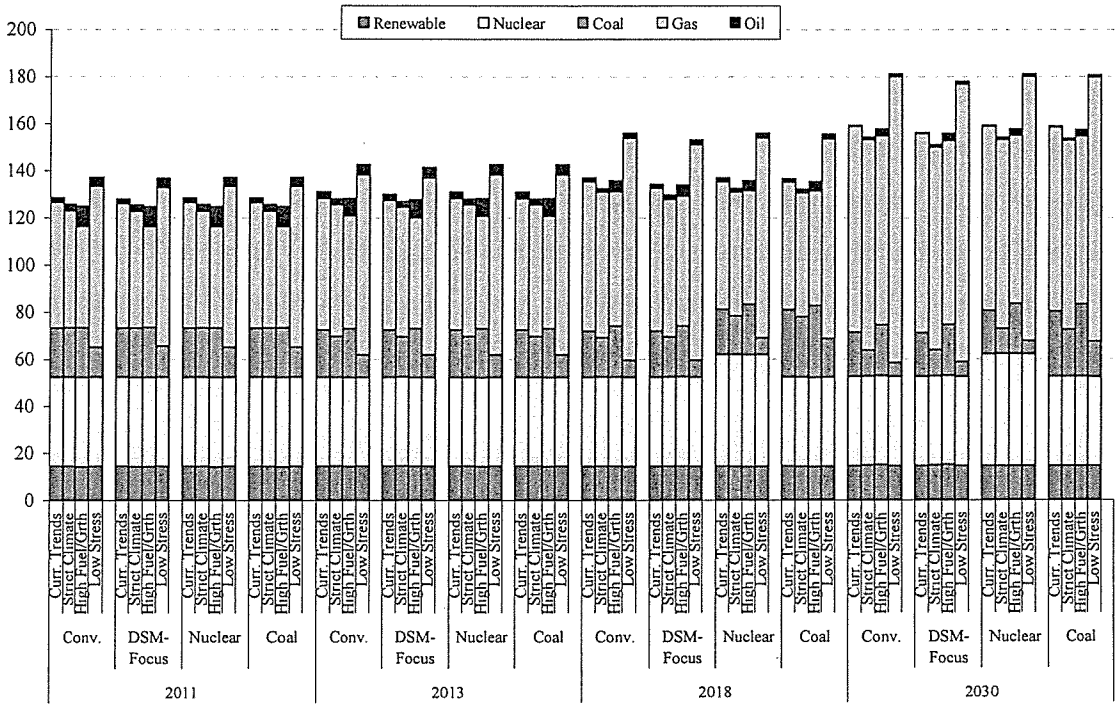


Figure 3.17: Total ISO Fuel Mix (Cumulative Generation in TWh)



B. SUMMARY OF FINDINGS

The analytical results presented above suggest the following ten high-level findings, assuming that planned capacity additions and DSM programs are realized as projected in each solution, each of which is discussed in more detail below:

1. Regional resource adequacy needs are satisfied for the next several years
2. Connecticut's local resource adequacy needs are satisfied for the foreseeable future
3. Market prices will continue to be high and volatile
4. Natural gas dependence will persist
5. External, uncontrollable factors are the primary drivers of customer costs
6. Renewable Portfolio Standards are unlikely to be fully met with renewable generation
7. Nuclear and DSM mitigate CO_2 emissions more effectively than other resource solutions
8. Increased DSM could reduce customer Costs, CO_2 emissions, and gas usage
9. Non-gas baseload generation would reduce dependence on natural gas
10. "Market Regime" vs. "Cost-of-Service" affects rate stability, and may have future customer cost implications

1. Regional Resource Adequacy Needs are Satisfied for the Next Several Years

After taking into account planned generation additions, recent and planned transmission projects, and demand-side measures that are planned or underway, and assuming no retirements, new electricity resources will not be needed to attain reliability targets for several years in Connecticut or elsewhere in New England. Under most plausible futures, New England as a whole will need additional resources beyond the next five years. As part of the overall New England market, Connecticut will share in this resource need, but additional resources need not be located within Connecticut in this time frame.

2. Connecticut's Local Resource Adequacy Needs are Satisfied for the Foreseeable Future

Planned generation capacity additions, transmission enhancements and demand-side measures mean that Connecticut will satisfy its Local Sourcing Requirement (LSR) for many years, perhaps decades, under the scenarios examined in this report. This is partially due to the projected addition of DSM and generating capacity, including 279 MW of quick start capacity needed to satisfy the Connecticut Local Forward Reserve Market (LFRM) requirements. However, this analysis assumes no significant retirement of generating capacity in Connecticut, although some of the older oil-fired units are projected to earn sub-normal returns and/or experience difficulties covering their fixed O&M costs over the longer term; potentially resulting in retirement or reapplication for "reliability-must-run" status. Also, no significant congestion price differentials are forecast between Connecticut and the rest of New England. Transmission enhancements already under construction and planned generation will resolve the significant bottlenecks and limited local supply resources that have affected Southwest Connecticut in the past.

3. Market Prices will Continue to Be High and Volatile

Despite an adequate supply of resources, Connecticut and New England electricity prices are likely to remain at levels that will concern consumers and regulators, and prices will remain volatile. This is due primarily to the fact that electricity prices in New England are closely linked to natural gas prices, as our study confirms. Gas prices are volatile and uncertain, and likely to remain fairly high.

4. Natural Gas Dependence Will Persist

Natural gas is the fuel for about 40% of New England's power, but its impact on market prices is disproportionately large. Because it will remain the dominant price-setting fuel for electricity, its influence on prices will continue regardless of future events or resource decisions. Dependence on natural gas for power generation poses two potential problems. First, consumers are exposed to high and uncertain power costs because gas prices are high and volatile. Second, using large amounts of natural gas for electricity generation increases both the likelihood and the potential impact of gas supply disruptions, particularly in the winter months when overall gas usage is highest. This study only notes differences of natural gas consumed, but does not analyze the increased probability or cost of potential fuel disruptions on generating capability.[10] But because much of the existing generation base is gas-fired, and gas is the price-setting fuel for electricity, to substantially change the region's dependence on gas would take a long time and exceptional effort and expense. This analysis did not investigate the sufficiency of gas supply, however; gas supply is a concern, and should be thoroughly investigated prior to developing a long term strategy for the addition of resources in Connecticut.

5. External, Uncontrollable Factors Are Primary Drivers of Customer Costs

External factors that cannot be controlled by utilities or regulators, such as gas prices, climate policy and economic growth, can have a much larger impact on market outcomes and resource costs than the factors that can be controlled. A large part of the reason for this is that factors such as gas prices or climate policy can affect all resources, existing and new, while resource strategies that involve physical investments in new resources only affect the portfolio at the margin. Although the impact of marginal physical resources on the overall market outcomes or resource costs are relatively small (because additions are small relative to the installed capacity base),procurement strategies might alter the contractual relationship between load-serving entities and generators, or direct investment in physical generating capacity by load-serving entities, could impact customer cost.

[10] PA 07-242 supports dual fuel capability with respect to certain generating units and at the discretion of the DPUC.

6. Renewable Portfolio Standards Are Unlikely to Be Fully Met with Renewable Generation

Appendix E describes recent experience under the Connecticut renewable portfolio standard (RPS) requirements as well as under similar policies in New England. The discussion in Appendix E concludes that the Connecticut RPS is unlikely to be met by renewable generation, but instead load serving entities (LSEs) are increasingly likely to rely on alternative payments to the state at a mandated price of $55 per megawatt-hour for any short fall. By the middle of next decade, the statewide annual customer cost of complying with the requirement would exceed $200 million. Connecticut has limited amounts of attractive renewable resource options; it has little economic potential for wind and solar power, and even less for other renewables like wave, tidal, geothermal, etc. Other parts of New England have more promising renewable resource potential (*e.g.*, wind in northern New England). However, even reliance on a regional rather than state-level approach may not resolve the problem for Connecticut, since it is possible that New England in aggregate will be unable to achieve its combined renewable targets. This issue warrants additional study, particularly regarding the potential to access remote renewable resources for Connecticut, which may require the development of additional transmission capacity.

7. Nuclear and DSM Mitigate CO_2 Emissions More Effectively than Other Resource Solutions

CO_2 emissions will increase under a Conventional Gas resource solution (though the additional DSM incorporated in all Resource Solutions helps to mitigate this somewhat.) Additional DSM will further limit CO_2 growth, but not cause a reduction. As expected, the addition of nuclear generation would cut a significant amount of CO_2 emissions, while additional coal capacity would increase it. Opportunities for coal with carbon sequestration are limited by a lack of the appropriate geology in Connecticut and New England.

8. Demand Side Management Could Reduce Customer Costs, CO_2 Emissions, and Gas Usage

If achievable as characterized in our analyses, DSM (both demand response and energy efficiency programs) are effective in mitigating future peak and energy growth. The analyses assume a substantial amount of "Reference Case" DSM in all Resource Solutions (*e.g.*, much more than assumed by the ISO in its load projections), and still more DSM in the DSM-Focus solution. This additional DSM, if it is similarly effective, would also be valuable. (This analysis

has not attempted to optimize the type or quantity of DSM programs, but simply evaluated two different levels of specified DSM programs.)

The results show that DSM can reduce overall customer costs. Under some circumstances, DSM can increase average unit costs (¢/kWh). When consumption volumes are changing, a change in unit costs may not accurately reflect customer impacts. How costs are recovered from particular customers or classes can affect whether their rates and/or costs go up or down. This is a question of cost allocation, a ratemaking issue not addressed here.

9. Non-Gas Baseload Generation Would Reduce Dependence on Natural Gas

Baseload generation (coal or nuclear), if procured in a way that mimics cost of service to consumers, can help to limit exposure to natural gas price risks, though if gas prices go down rather than up, this could commit customers to higher fixed costs. Under a purely market-based regime (i.e., if baseload generation was merchant-owned and procured for customers at market prices), customers would receive no protection from gas prices; their costs would be virtually the same as if conventional gas generation had been added.

10. Market Regime vs. Cost-of-Service Affects Rate Stability and May Have Future Customer Cost Implications

As constructed/assumed, the hypothetical "Cost-of-Service" regime has substantially lower costs than the "Market" regime, across all scenarios and strategies studied; however, these results indicate more analysis is warranted. The overall cost levels used in the analysis may not offer a realistic comparison on a regional market basis, because it is probably not possible to put all generating assets back under cost of service regulation at historic embedded costs. The actual purchase costs for existing generation would not likely be at the levels assumed in the Cost of Service results because the fixed costs for some of the existing assets assumed in the Cost of Service analysis are below current market values. However, output from new construction owned outright and output from new assets acquired via long-term contracts could potentially be obtained at prices reflecting Cost of Service, but this was not evaluated in this study. The results also show that the range of costs is much smaller under Cost of Service. The potential range of total supply costs is generally lower than the range of market prices. This is primarily because

under a market regime, the market price for all power is determined by the last unit of supply. In very simple terms, if the cost of the last unit of supply increases by 10%, then under a market regime customer costs increase by 10%. But the total cost of generating power from all sources varies by much less than 10% (many of these costs are fixed and don't vary with the last unit's costs). If customers were to be supplied under a regime more closely reflecting actual generating costs, customer costs will increase by less than 10%. Even if only some assets are procured on a cost basis, this will reduce customers' exposure to uncertain and volatile prices. As discussed below, it may be possible to procure power from some existing and/or new resources in ways that mimic cost-based pricing and allow customers to enjoy some cost-stabilization.

It is crucial to note here that while it is possible to reduce the uncertainty and volatility of customers' costs, it may not be possible to substantially reduce the expected level of costs in the near- or mid-term. However, long-term contracts for the output of new or existing assets can reduce uncertainty which can lower costs. Such questions of procurement and risk management are beyond the scope of this resource planning effort, but are likely to be important issues to consider in addressing the concerns of Connecticut customers.

SECTION IV: RECOMMENDATIONS

The key findings outlined above are based upon the analysis performed by *The Brattle Group*, and lead to four primary recommendations representing a possible path forward to improve electricity procurement in Connecticut. Steps taken in response to these recommendations could help provide Connecticut customers with reliable, environmentally responsible electric service at more stable prices and potentially lower customer costs. Our primary recommendations regarding resource planning and procurement are:

1. Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.
2. Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation.
3. Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England.
4. Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas (though it will not be possible to eliminate gas dependence).

Recommendation 1: Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.

The potential for increased DSM to reduce customer costs, gas usage, and environmental emissions demonstrated in this analysis suggests that DSM should be pursued more aggressively. State regulatory authorities should examine, and where possible, explore methods to implement additional, cost-effective DSM. This would facilitate utility DSM programs to exceed current levels and expand upon the success of existing DSM programs. While the need for capacity is several years off in Connecticut, DSM programs are more cost-effective if they are pursued consistently over time, so it is reasonable to begin the ramp-up to more aggressive DSM programs in the near term.

The DSM resource investments assumed in this report far exceed the (already aggressive) levels pursued by the Companies to date. The pace and magnitude of this expansion warrants careful monitoring of resource availability, costs, and operational effectiveness as the programs develop over time.

Recommendation 2: Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation.

At the present time, the Companies are constrained to enter into contracts with third-party suppliers with durations not to exceed three years to satisfy standard offer service obligations, which ensures that customers are exposed to power supply prices driven by short-term market prices. Our finding that customer costs would be more stable under a hypothetical cost-of-service regime suggests that supply arrangements incorporating cost-of-service principles could help to stabilize customer rates and potentially, under certain conditions, lower prices for the customer. This could be achieved by providing the Companies greater flexibility in the structures and duration of their power supply arrangements on behalf of customers.

Options may include long-term contracting, procuring energy, capacity and reserve products individually from generators and/or the outright ownership of generating assets, including baseload generation that is not dependent on natural gas. By reducing the extent to which utilities are forced to procure power through short-term contracts driven by regional spot market prices, such alternative procurement options can reduce customers' exposure to uncertain and potentially high gas prices, and may provide to customers some benefits of a diverse fuel mix. Addressing these issues may involve the use of procurement strategies and risk management tools (such as fuel hedging strategies to complement electricity procurement) that go beyond what can be done in a resource planning context. In addition, strategies such as these should be coupled explicitly with the assurance of recovery of supply costs associated with approved long-term power procurement contracts.

Recommendation 3: Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England.

Connecticut's renewable portfolio standard as currently structured, while supporting Connecticut's renewable goals, may impose additional costs on Connecticut customers without necessarily promoting new renewable generation to displace conventional generation. This observation suggests that additional study of RPS structure and costs is warranted at both the state and regional level to determine the best ways to meet future RPS requirements. At the state level, for example, the criteria for disbursing funds derived from alternative compliance payments might be re-examined under the current circumstances. Further analysis could also examine the potential to fashion regionally-coordinated policies to address possible renewable shortfalls and/or regional projects in transmission and renewable capacity.

Recommendation 4: Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas.

Non-gas baseload generation (*e.g.*, coal, and nuclear) offers a greater reduction in gas use (particularly in wintertime, when deliverability concerns are highest) than other resource options studied in this report. Although not assessed in this report significant renewable generation could also mitigate gas dependence.

To the extent that market participants' investment in non-gas-fired baseload generation is deemed insufficient to address these risks, state regulatory authorities should consider allowing contractual or ownership arrangements or other policy options to enable or encourage investment in such baseload capacity. Such options should be considered in concert with efforts to reduce dependence on natural gas use in all sectors (*e.g.* heating). Both the cost and CO_2 emissions implications of all non-gas options should be considered.

SECTION V: STUDY LIMITATIONS AND FURTHER ANALYSIS

PA 07-242 requires that the Companies submit a resource procurement plan each year and proscribes a process for the CEAB and DPUC to review, modify and approve. As the inaugural effort in this annual process, the analysis in this report is comprehensive and complies with the essential requirements of PA 07-242.

Notwithstanding the overall completeness of the report, any analysis – especially an initial undertaking responding to a recurring requirement – will focus on the most important foundational elements and therefore afford less attention to some topics. Some of these topics are emerging as important, but are more usefully analyzed in detail when the overall direction of procurement policy is established, or are beyond the scope of an initial resource planning analysis. Some of these issues may become more important as procurement plans evolve or as markets change, and could be considered for inclusion in subsequent analyses.

The resource planning analysis contained in this report has the following general limitations (with citations to Section 51 items where appropriate) – all of which could be subject to future analysis as procurement plans and policies evolve:

This study contains only limited analysis related to transmission. This study did not provide a cost/benefit analysis of transmission options; did not compare the economics of transmission vs. generation or vs. demand-side options; and does not constitute a transmission reliability assessment. Such an assessment would address the mandatory reliability criteria and standards established by various national and regional bodies, which are applied to the New England transmission system as part of the annual New England Independent System Operator (ISO-NE) Regional System Plan (RSP). In addition, distribution improvements are not addressed. (Section 51(c)(3) recommends T&D analysis.)

This is not a siting analysis for new generation capacity. While generation capacity expansion was modeled in order to estimate impacts on electricity markets, resource costs and customer costs, the optimal location of such capacity was not addressed (Section 51(d)(3) implies

consideration of location). These issues are reasonably addressed at a later stage in resource planning, and require substantial data on candidate sites.

This is not a procurement risk management study. While the analysis does illuminate some of the risks associated with pursuing different resource strategies under uncertain future market conditions, it does not formally address physical or financial portfolio risk management or hedging considerations. The recommendation to alleviate some of the procurement constraints on contract duration and structure (*e.g.*, prohibition on power supply contracts that exceed three years) is based primarily on the potential benefits implied, but "optimal" contract lengths are not explored, as these are beyond the scope of a resource planning analysis (Section 51(c)(5) specifies such an analysis).

This is not a regional renewable energy market study. The recommendation to analyze and revisit the Connecticut renewable portfolio standard (RPS) policy in light of the evolving renewable energy market in New England is based on the analysis contained in Appendix E. That discussion cites recent market evidence and other analyses that indicate the potential for a New England and Connecticut shortfall in renewable energy development relative to the RPS targets. However, a thorough examination or modeling exercise of the region's renewable energy market is beyond the scope of a resource planning study; hence the recommendation that additional analysis be pursued on this topic.

There also are many ways the existing analysis can be refined or extended if such enhancements are deemed helpful. These include:

- Additional sensitivity/scenario analysis
- Expanding the suite of evaluation metrics to address additional issues and concerns
- Evaluation of blended resource solutions, *e.g.*, DSM and nuclear
- Evaluation of resource solutions at different scales/levels
- Evaluation of hybrid market/cost-of-service procurement strategies
- Examining how periods of market disequilibrium (*e.g.*, capacity market boom-bust cycles) might affect the evaluation of resource solutions

- Harmonizing electricity market price outlooks used in previous DSM evaluations with those in this study to explore the impact on cost-effectiveness tests
- Examining the interplay between market (price-induced) conservation and the incremental impact of DSM programs
- Additional optimization of DSM program elements to enhance overall effectiveness and to maximize desired impacts on energy and peak load
- Additional refinement of resource characterization and potential in light of rapidly changing technology, cost and performance; for example, an examination of the potential of combined heat and power (CHP) and distributed resources to contribute to power supplies over the long run.

Finally, a study of this nature must necessarily utilize current information and data, while energy markets and policies across the U.S. are changing rapidly. Likewise, this analysis will need to evolve as new information becomes available. Critical updates over the next year might include incorporating the following new data:

- Much better information about the capacity balance and costs in ISO-NE will be available after the Forward Capacity Market auction occurs in February, 2008.
- Additional information regarding generation (conventional and renewable) development and retirements or cancellations in ISO-NE.
- New transmission projects that may be proposed.
- New fuel price and emissions (SO_2, NOx, Hg) price forecasts.
- Demand-side management activities in other New England states (*e.g.*, Massachusetts energy goals clarified).
- Information on CO_2 allowance price levels from various states' RGGI allowance auctions.
- Emerging clarity on the direction of national climate change policy.

APPENDIX A: ELECTRICITY MARKET ANALYSIS

This Appendix discusses ISO-NE's energy, capacity, and operating reserve markets generally, outlines recent market performance and the future outlook for Connecticut, and describes this study's analytical approach to projecting prices in these markets.

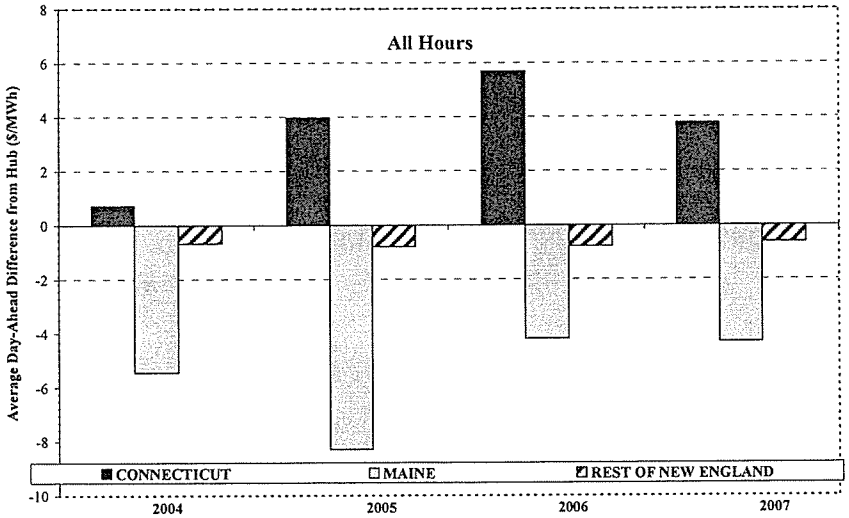
I. ISO-NE MARKET OPERATIONS AND CONCERNS

a. ENERGY

The day-ahead and real-time markets that ISO-NE administers clear and settle at locational marginal prices (LMP). LMPs reflect not only the old-fashioned, merit-order-based, energy clearing price where supply and demand curves intersect, but also transmission congestion and marginal losses. Nodes located electrically near the sending end of a constrained transmission facility are priced lower than their neighbors, reflecting the fact that generation must be re-dispatched out of merit order in order to accommodate load in transmission-constrained areas. Nodes located on or near the receiving terminus of a constrained facility experience higher prices than nodes on the other side of the constraint. Import-constrained load zones,[1] such as Connecticut (and especially Southwest Connecticut over the past several years), tend to have relatively high prices. Generation pockets, such as Maine, tend to have relatively low prices, as illustrated in Figure A.1.

[1] Import constrained load zones are areas within New England that may not have enough local resources and transmission import capability to reliably serve local demand.

Figure A.1: Annual Average Difference in Day-Ahead Prices ($/MWh)



Sources and Notes: ISO-NE market data compiled by Global Energy Decisions, Inc., The Velocity Suite; 2007 includes only through October; Rest of New England LMP is obtained using a load weighted average for the other 6 zones in New England i.e. WCMASS, NEMASS, SEMASS, RHODE ISLAND, VERMONT and NEW HAMPSHIRE.

In turn, contracts for power, including wholesale supply contracts for standard offer service, are presumably related to suppliers' expectations for LMPs. Hence, residential rates from 2005 through 2007, and commercial rates and weighted average rates in 2007 have been higher in Connecticut than in Maine or the rest of New England, as shown in Table A.1.

Table A.1: Recent Electricity Rates in ISO-NE States

	Residential Rates (¢/kWh)			Commercial Rates (¢/kWh)			Industrial Rates (¢/kWh)			Weighted Average Rates (¢/kWh)		
State	2005	2006	2007	2005	2006	2007	2005	2006	2007	2005	2006	2007
CT	13.6	16.9	18.8	11.5	14.0	15.4	9.4	11.7	12.8	12.1	14.8	16.3
MA	13.2	13.8	15.1	10.6	12.4	13.2	7.3	8.8	10.3	10.6	11.8	13.2
ME	13.4	16.6	16.5	12.4	15.5	15.3	9.2	13.0	13.5	12.2	15.4	15.4
NH	13.5	14.7	14.9	12.1	14.1	13.9	11.5	11.6	12.7	12.5	13.8	14.0
RI	13.0	15.1	13.9	11.7	13.5	12.7	10.0	12.5	12.3	12.0	14.0	13.1
VT	13.0	13.4	14.1	11.3	11.7	12.2	7.8	8.3	8.8	10.9	11.4	12.0

Source: EIA 826 database, Brattle analysis

LMPs theoretically incorporate into prices the effects of each generator's output and each customer's load on system dispatch costs, thus providing price signals for economically efficient generation dispatch and consumption decisions at every location and every moment. LMPs can also help to induce optimal location of investment in new supply and demand-side resources. However, these theoretical efficiencies have not been fully achieved for a number of reasons, including the inability of the existing transmission system to accommodate new generation

(without significant upgrades) in certain locations such as Southwest Connecticut, the lack heretofore of locationally-differentiated capacity prices (discussed below).[2] This led to a situation in which Southwest Connecticut had insufficient supply for reliable operation going forward, even as prices remained the highest in New England.

b. Installed Capacity Market

ISO-NE imposes a resource adequacy requirement on all load-serving entities (LSEs) in order to limit expected loss of load due to inadequate supply to no more than one day in ten years. ISO-NE also administers a capacity market to facilitate a liquid, transparent mechanism for market participants to buy and sell capacity to meet their resource adequacy requirement.

The capacity market has historically not distinguished between resources located in load pockets from those located in generation pockets. Nor were resource adequacy requirements enforced more than a year forward, thus limiting new resources' ability to secure an initial revenue stream before commencing construction. The perceived failures of the initial capacity market, including the concern that it would not induce sufficient resources to locate in load pockets such as Southwest Connecticut due to the lack of location-specific prices, spurred ISO-NE to commence a stakeholder process to modify the capacity market.

ISO-NE proposed the establishment of a forward market for locationally-differentiated capacity, such as New York and PJM now have. This proposal proved to be highly controversial and was litigated at FERC. Ultimately, a settlement was reached in which ISO-NE agreed to establish a forward capacity market (FCM) with a three-year lead time for one-year capability periods, but with no explicit locational provisions. Locational price premiums or discounts could arise if ISO-NE finds, based on a study conducted annually, that there are binding internal transmission constraints that prevent generation in one part of the region from reliably serving load in another part of the region. The first FCM auction will occur in February, 2008 for the 2010/11 capability year.

[2] In addition, most customers pay fixed rates and are not exposed to time-varying spot prices, allowing them to over-consume during peak periods.

c. Operating Reserves Markets

In order to maintain reliability in the event of contingencies and unexpectedly high load, ISO-NE maintains operating reserves, i.e., capacity that is unloaded and ready to produce power quickly if needed. The region as a whole must carry sufficient operating reserves to cover the single largest contingency and half of the second largest contingency. In addition, the load pockets of Connecticut, and NEMA/Boston, must maintain 30-minute operating reserves locally, which are typically provided by fast-start resources such as combustion turbines.[3]

ISO-NE administers forward and real-time markets in order to facilitate the efficient supply of operating reserves, with the full requirement to be purchased forward semiannually in the non-spinning reserve categories and with spinning reserves and increments/decrements for non-spinning reserves transacting in real time. The forward reserve market (FRM) price, including the locational forward reserve market (LFRM) for Connecticut, is capped at $14/kW-month minus the capacity price.[4] Because there has been a shortage of reserves in Connecticut, the price has been set by the cap in recent auctions. The shortage has also required the use of more expensive spinning reserves (paid for through "uplift" payments) and/or underutilization of the transmission import capacity. These costs are now being addressed in the Department of Public Utility Control's Docket No. 07-08-24, *DPUC Investigation of the Process and Criteria for use in Implementing Section 50 of Public Act 07-242 – Peaking Generation*, as discussed below.

d. Reliability-Must-Run Generation

Much of the generation capacity in Connecticut is composed of old, oil and gas-fired, steam turbines that are expensive to operate. These units have been kept online and operating through reliability-must-run (RMR) contracts with ISO-NE that provide for out-of-market payments. With the introduction of the forward capacity market, these RMR contracts are planned to be eliminated. A concern in Connecticut is that without the RMR contracts, some of the older generating units might retire and leave a critical supply gap in Connecticut.

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[3] The sub-load pocket of Southwest Connecticut has also had its own local requirement, but this requirement is expected to decrease or disappear following the expected completion of the Southwest Connecticut Reliability Project Phase II in 2009, as discussed in ISO-NE's *2007 Regional System Plan* at p. 43-45.

[4] *2006 Annual Markets Report*, ISO New England, June 11, 2007, p. 72.

II. Future Outlook for Connecticut

Shortages of capacity and operating reserves in Connecticut, particularly Southwest Connecticut, have been at least partially addressed by new transmission as well as new supply and demand-side resources. As documented more completely in Appendix G, the new resources include:

- **New transmission**, including the Southwest Connecticut Phase I project (345 kV line from Bethel to Norwalk, completed in 2006), the Southwest Connecticut Phase II project (345 kV lines from Middletown to Norwalk, under construction and to be completed in 2009), smaller reliability projects, and potentially the New England East-West-South (NEEWS) project.
- **Recent and planned new DSM** is described in the DSM section, and amounts to an approximate 700 MW peak reduction by 2011 and more than 1,000 peak reduction by 2018.[5] EE programs also reduce future energy requirements by 1,168 GWh by 2011 and 2,821 GWh by 2018.
- **Existing, recent, and planned new generation supply** includes approximately 7000 MW existing and recently installed capacity, plus 1,107 MW of additional planned generation by 2011. Table A.2 shows the additional planned generation by unit.
- In addition, planned projects do not completely fill Connecticut's shortage of operating reserves, so it was assumed that an additional 279 MW of **new fast-start** capacity will be built, as explained below.

Table A.2: Planned Generating Unit Additions and Expansions in ISO-NE by 2011

Unit Name	Unit Type	Zone	Summer Capacity (MW)	Winter Capacity (MW)	Fuel Name
UNIT ADDITIONS					
Waterbury	CT	SW CT	80	96	Natural Gas
Kleen Energy	CC	Rest of CT	560	620	Natural Gas
Wallingford/Pierce	CT	SW CT	100	100	Natural Gas
DG Capital Grant Projects*	CT	SW CT and Rest of CT	96	96	Natural Gas
Renewable Energy Contracts	Steam	SW CT and Rest of CT	150	150	Biomass
UNIT EXPANSIONS					
Cos Cob Expansion	GT	Norwalk-Stamford	40	40	FO2
Millstone Point 3	Nuclear	Rest of CT	81	81	Uranium
		Total (all is in Connecticut)	**1,107**	**1,183**	

*DG Capital Grant projects reduced from 130 MW to 96 MW because 34 MW are counted as demand reductions

[5] Measured at the customer meter.

The potential retirement of existing generating units by plant owners can not be predicted with certainty, but it was assumed that no existing capacity would retire,[6] based on a preliminary economic screening analysis. The analysis consisted of comparing units' energy and capacity revenues to their going-forward avoidable fixed O&M costs. Our data source for the fixed O&M costs was the RMR filings by the old steam turbines in Connecticut, as summarized in Table A.3, below. (This screening analysis considered only the RMR units because their RMR status suggests potentially inadequate earnings to maintain operations and because the RMR contract contains detailed data that facilitates a screening analysis. Units outside of Connecticut were not considered.) Energy and capacity revenues were estimated based on the model results, since RMR contract payments are expected to be discontinued upon the inception of the forward capacity market.

Table A.3: Fixed O&M Costs of RMR Units in Connecticut

Station/Unit	Summer Capacity (MW)	Fixed O&M ($)	FOM ($/kW-Mo)
NRG -- Middletown 2-4, and 10	770	41,071,316	4.44
NRG -- Montville 5, 6, 10, and 11	494	25,608,334	4.32
Milford 1 and 2	492	21,315,292	3.61
PSEG -- New Haven Harbor	448	16,996,000	3.16
PSEG -- Bridgeport Harbor 2	130	6,009,000	3.84
NRG -- Norwalk Harbor 1 and 2	330	29,497,659	7.45

Source: Company RMR Filings to ISO-NE

A unit's entire FOM cost should not be considered avoidable through retirement because there are costs of retiring a plant and maintaining or remediating a site, if applicable. Furthermore, one or two years with low revenues would probably not induce retirement, given the cost of giving up an option to capture significant value in a good year. Hence, we did not consider retiring units unless revenues fell several dollars per kW-month short of covering their fixed O&M costs. With capacity prices in the $3-4/kw-month range in all scenarios for 2013 through 2018 (see Table A.7), all units passed the preliminary screen except for Norwalk Harbor 1 & 2.

[6] However, units that have already retired are treated as such in this study, including New Boston 1 (350 MW), which retired in 2007.

However, we understand that those units or other new resource may be necessary for reliability in the Norwalk area in order to protect against contingencies when one of the new 345 kV transmission lines into Norwalk is out of service. Therefore, we assumed that Norwalk Harbor 1 & 2 would stay online in spite of our screening analysis.

Load growth will partially offset the planned resource additions. ISO-NE forecasts an average annual load growth rate of approximately 1.7% for summer peak load and 1.2% for energy over the next 10 years, before considering new DSM.[7] (Load growth could be higher or lower, depending on economic growth, energy prices, and efficiency, as discussed in the Appendix B).

All planned and expected changes to the supply and demand have been included in the resource balances shown in Tables 2.2 and 2.3 in the main report. As Tables 2.2 and 2.3 indicate, there is no significant resource gap expected in New England until 2013-2016, depending on the trajectory of load, and there is no shortage relative to Connecticut's local sourcing requirement until 2030.

Other fundamental changes likely to affect electricity markets over the next ten years include changes in fuel prices and emission allowance prices. Significantly, carbon allowances will be introduced under RGGI and potential federal climate legislation, as discussed in Appendix F.

III. Modeling Approach and Findings: Future Prices of Energy, Capacity, and Operating Reserve

This study investigates the resource solutions and procurement strategies that would achieve the best combination of reliability, customer costs, and other policy objectives, including environmental, energy security across a range of potential future scenarios. Resource solutions are evaluated using the DAYZER model to simulate energy market prices, fuel use and emissions, with other complementary analyses to estimate FCM and LFRM prices.

[7] *2007-2016 Forecast Report of Capacity, Energy, Loads, and Transmission*, ISO New England, April, 2007, p. 7.

The starting point for the analysis is an accurate representation of the existing system, which is incorporated in the DAYZER model, plus the planned and expected changes to transmission and generation capacity and DSM, as described above. The key assumptions and data inputs are documented in Appendix G. In addition, the data inputs regarding uncertain exogenous factors, such as load growth and fuel and emission allowance prices, are varied across scenarios, as described in Appendix B.

Finally, in future years in which there is insufficient supply to meet ISO-NE's resource adequacy criteria, it is assumed that additional unplanned resources will be added to fill the gap. The specific "resource solutions" that are evaluated in this study help to fill such gaps, and an economic mix of new gas-fired combustion turbines (CTs) and combined-cycles (CCs) are assumed to be built to fill any remaining gaps.

a. Energy Market

Given the data inputs representing the elements of supply, demand, and transmission, DAYZER simulates a chronological, bid-based, security-constrained, unit-commitment and dispatch. The model seeks to minimize the total cost to serve load, much like ISO-NE operates the system and administers the market.

It is important to note, however, that the DAYZER forecasts used in this study do not include several elements that create volatility in actual markets. First, there are no transmission outages, which are typically responsible for substantial transmission congestion in actual markets. Second, all generating units are assumed to offer energy at their incremental costs of production: incremental heat rate x fuel price + variable O&M costs + emissions allowance costs. There are no bid adders representing other opportunity costs (such as limited run hours for environmental reasons, or limited fuel supply) or the pursuit of higher margins when market conditions allow. While bidding above marginal cost has been observed in regional organized markets during selected time periods, an estimate of the impact of such behavior is beyond the scope of this study, and is not likely to vary between resource solutions examined. In addition, if there are no barriers to entry, an increase in energy prices would be largely offset by a decrease in capacity prices through a relationship discussed in the next subsection.

The key steps DAYZER performs are:

1. Schedule planned maintenance so as to make the available capacity minus the load as level as possible across the year, i.e., mostly in the Spring and Fall; schedule forced outages randomly such that each unit's target forced outage rate is met.
2. Commit sufficient thermal capacity each day to meet the load plus spinning reserve requirement not already met by hydro generation. Commitment decisions, i.e., when to turn on and off each unit each day, if at all, require a multi-period cost-minimization with many degrees of freedom and can not be optimized perfectly in a reasonable amount of time, hence DAYZER uses heuristics to find a near-optimum. The heuristics account for transmission constraints and the operating characteristics of the units, including their minimum-up-time (MUT) and startup costs as well as their variable costs. DAYZER properly opts not to commit steam units with high-MUT and high startup costs to serve peaking duty when a low-MUT, low startup cost combustion turbine can do it at a lower overall cost (albeit with a higher variable cost setting a higher market price for energy). This, and the fact that generation in constrained-off locations such as Maine is also not committed, often leads to higher and more realistic prices than a simpler production cost model might suggest. (Off-peak prices are also lower due to the fact that MUTs are respected, causing some units whose bids exceed their LMPs to generate at minimum load).
3. Finally, given the generating units that have been committed for each day and each hour, DAYZER dispatches the system to meet the load and provide the required amount of spinning reserves at least cost.

The key outputs of the model are the hourly generation, cost, and emissions at every generating unit, the flows on every monitored transmission facility, and the LMP at every node. As in ISO-NE's actual energy market, DAYZER's hourly LMPs correspond to the marginal cost of serving load at each node, given by the marginal cost of re-dispatching all of the marginal units in order to serve an increment of load at that node without overloading any transmission constraints.[8] LMPs also incorporate a marginal loss component given by the price at the reference bus multiplied by nodal loss factors that DAYZER draws from a database of loss factors under similar load conditions.

Resulting annual average energy prices are shown in Table A.4, below. Table A.4 shows the annual average price in each zone, given by the hourly LMP at a representative node for each

[8] When there are N binding transmission constraints, there are N+1 marginal generating units.

zone summed across hours and divided by 8,760 hours. As the table shows, prices vary much less by solution than by scenario, the differences being driven primarily by gas prices. In addition, prices do not vary by more than a few dollars among Connecticut zones, nor are they significantly higher than prices in nearby West-Central MA. This differs from the recent pricing patterns in which prices were much higher in Norwalk-Stamford than elsewhere (see Table A.5 below), presumably because of the Southwest Connecticut Reliability Projects, which bring two major 345 kV lines into Norwalk and relieve congestion into Norwalk-Stamford.

Table A.4: Average LMP ($/MWh in 2008$) for All Scenarios and Solutions

		2011				2013				2018				2030			
Scenario	Solution	Norwalk	SW CT	Rest of CT	WC MA	Norwalk	SW CT	Rest of CT	WC MA	Norwalk	SW CT	Rest of CT	WC MA	Norwalk	SW CT	Rest of CT	WC MA
Current Trends	Conventional	73.0	72.0	73.0	71.6	68.7	67.8	68.7	67.4	74.2	73.2	74.3	72.8	82.9	80.5	81.7	80.2
Current Trends	DSM-Focus	73.0	71.9	72.9	71.5	68.4	67.3	68.3	67.0	74.2	72.9	73.9	72.5	82.3	80.5	81.6	80.0
Current Trends	Nuclear	-	-	-	-	-	-	-	-	73.4	72.2	73.2	71.8	80.2	77.5	78.6	78.9
Current Trends	Coal	-	-	-	-	-	-	-	-	73.4	72.2	73.2	71.8	80.2	77.5	78.6	78.9
Strict Climate	Conventional	77.0	76.3	77.4	75.9	83.4	82.0	83.2	81.6	87.0	85.5	86.8	85.1	102.3	100.1	101.5	99.7
Strict Climate	DSM-Focus	76.9	76.2	77.2	75.8	82.9	81.4	82.6	81.0	87.9	86.3	87.6	85.9	102.1	100.3	101.7	99.9
Strict Climate	Nuclear	-	-	-	-	-	-	-	-	86.6	85.1	86.3	84.7	99.9	96.6	98.1	97.7
Strict Climate	Coal	-	-	-	-	-	-	-	-	86.6	85.1	86.3	84.7	99.9	96.6	98.1	97.7
High Fuel/Growth	Conventional	103.7	106.9	108.4	106.4	97.1	99.3	100.7	98.7	105.2	105.7	107.3	105.3	114.0	113.4	115.1	113.0
High Fuel/Growth	DSM-Focus	103.6	106.5	108.0	106.0	97.4	99.2	100.6	98.7	106.7	107.1	108.6	106.5	116.5	116.2	117.8	115.7
High Fuel/Growth	Nuclear	-	-	-	-	-	-	-	-	103.1	103.2	104.7	104.0	112.1	109.9	111.6	113.1
High Fuel/Growth	Coal	-	-	-	-	-	-	-	-	103.1	103.2	104.7	104.0	112.1	109.9	111.6	113.1
Low Stress	Conventional	50.8	50.6	51.4	50.4	48.3	48.0	48.7	47.7	52.9	52.2	53.0	52.0	59.2	57.6	58.5	57.2
Low Stress	DSM-Focus	50.9	50.9	51.6	50.6	48.6	48.1	48.8	47.8	53.3	52.4	53.2	52.2	58.2	57.1	58.0	56.6
Low Stress	Nuclear	-	-	-	-	-	-	-	-	52.2	51.4	52.1	51.6	56.5	54.6	55.4	55.4
Low Stress	Coal	-	-	-	-	-	-	-	-	52.2	51.4	52.1	51.6	56.5	54.6	55.4	55.4

Table A.5: Actual LMP ($/MWh in 2008$) Data at Representative Units

Year	Norwalk	SW CT	Rest of CT	WC MA
2005	108	85	85	83
2006	87	66	67	63
2007*	76	72	73	70
Average	90	74	75	72

Sources and Notes:

*Actual LMP data for 2007 include data through 12/21/2007.

Annual average GDP deflator data are from the Federal Reserve Bank of St. Louis.

Table A.6 below compares zonal average prices from our 2011 "Current Trends" scenario / Conventional resource solution to actual prices from the past three years. DAYZER prices are lower than actual 2005 prices, probably because of the very high gas prices in 2005 following Hurricane Katrina. DAYZER prices are 10-20% higher than actual prices in 2006-07, but average market heat rates (based on the hourly electricity prices divided by gas prices) are

similar. DAYZER market heat rates outside Connecticut are a few percent higher than actual 2006-07 heat rates, which makes sense directionally because of load growth (not quite offset by new capacity or DSM), higher oil prices, and the introduction of a small CO_2 allowance price in 2011.

Table A.6: LMP and Market Heat Rate Comparison between DAYZER and Actual Data

	Average Fuel Price ($/MMBtu in 2008$)				LMP ($/MWh in 2008$)				Market Heat Rate (MHR) (Btu/kWh)				% Difference MHR DAYZER vs. Actual		
ZoneName	DAYZER	2005	2006	2007*	DAYZER	2005	2006	2007*	DAYZER	2005	2006	2007*	2005	2006	2007*
CT Zone	8.5	10.7	7.9	8.5	73.6	89.7	70.3	71.6	8,741	8,494	8,981	8,837	3%	-3%	-1%
Maine Zone	8.2	10.5	7.8	8.4	68.7	76.4	59.7	63.5	8,168	7,319	7,739	7,955	12%	6%	3%
NE MA Boston Zone	8.5	10.6	7.9	8.5	71.3	86.1	63.3	66.0	8,482	8,223	8,120	8,175	3%	4%	4%
New Hampshire Zone	8.2	10.6	7.8	8.4	71.1	81.2	61.9	66.3	8,745	7,775	7,997	8,282	12%	9%	6%
Rhode Island Zone	8.4	10.6	7.8	8.4	71.2	82.2	61.8	65.5	8,514	7,854	7,943	8,151	8%	7%	5%
South Eastern MA Zone	8.5	10.6	7.9	8.5	71.2	82.1	62.2	67.4	8,469	7,810	7,945	8,359	8%	7%	2%
Vermont Zone	8.2	10.6	7.8	8.4	73.3	85.0	64.0	69.1	8,968	8,091	8,207	8,580	11%	9%	5%
West Central MA Zone	8.5	10.6	7.9	8.5	72.7	84.9	64.0	68.2	8,646	8,073	8,178	8,426	7%	6%	3%

Sources and Notes:

Actual 2007 LMP data only include data up until 10/30/2007, and are compared to DAYZER results from January 1 through October 30.
Actual LMP data are downloaded from Global Energy Decisions, Inc., The Velocity Suite, November 2007 data release.
Annual average GDP deflator data are from the Federal Reserve Bank of St. Louis.
Actual natural gas price data are the Algonquin Citygate prices downloaded from Gas Daily added to the local distribution charges from DAYZER.
DAYZER natural gas price data are the Henry Hub prices plus basis differentials and local distribution charges.
The market heat rate is calculated as the annual average of the hourly LMP/Gas Price x 1000.

b. Capacity (FCM)

In the long-run, a competitive market with minimal barriers to entry should price capacity at the net cost of new entry (Net CONE). Net CONE is given by the capital carrying charge and fixed operating and maintenance costs of the new plant that are not expected to be covered by operating margins from the sale of energy and ancillary services. Typically, it is assumed that the relevant capacity price-setting technology is a combustion turbine because it is nearly a pure capacity machine, i.e., it does not earn very large energy margins. For existing resources, ISO-NE has established a price floor for the first FCM auction based on 0.6 x Net CONE and a price ceiling of 1.4 x Net CONE, where Net CONE is assumed to be $7.5/kW-Month for a new combustion turbine. The same floor also applies to new resources that do not leave the auction.

In this study, it is assumed that the capacity market will clear at the floor in 2010/11, when a substantial surplus is expected. It is assumed that the capacity price will then trend toward Net CONE when the market reaches supply/demand equilibrium in 2013-16, depending on the scenario. However, this study deviates strongly from ISO-NE's Net CONE because it rejects

ISO-NE's assumption that a combustion turbine is the relevant technology with the lowest Net CONE. This study finds that, based on the same cost assumptions that ISO-NE used (but slightly inflated to reflect recent increases in the cost of new plant), a combustion turbine would have a Net CONE of approximately $6.1-9.1/kW-Month (=$4.9-6.8 capital carrying cost + $2.2-2.4 FOM –$0.2-1.7 energy margin), depending on the scenario and year. However, for the foreseeable future, a combined cycle would have a much lower Net CONE of $2.2-8.1/kW-mo, depending on the scenario (mostly below $4.5/kW-Month). Net CONE = $5.9-8.7 capital carrying cost + $2.5-2.7 FOM – $2.9-8.0 energy margin (mostly $6.0-8.0) depending on the scenario. This technology has a higher installed cost than a combustion turbine but substantially higher energy margins due to its lower heat rate. With its lower Net CONE, it would set a capacity price significantly below a combustion turbine's Net CONE. (In the alternative, if the capacity price were set by a combustion turbine's Net CONE, a combined cycle could enter and earn more than its cost of capital. More combined cycles would enter until capacity and energy prices dropped to a level at which the last unit just earned its cost of capital).

Table A.7 below shows the elements of these calculations. Note that the costs and revenues vary by location, and Table A.7 shows only the most economic location in each case. Where no unit exists, a 1 MW test unit was used as an indicator. Test units in the Norwalk-Stamford area were excluded because prices and energy margins appear slightly inflated there by a binding transmission constraint (post-contingency flows on Ely-Glenbrook 115 kV) that would probably be economic to resolve through transmission enhancements.

Table A.7: Summary of Connecticut Capacity Price by Scenario, Resource Solution, Study Year, and Unit Type

	2011						2013					2018					2030				
	Capital at Best Location [1]	FOM at Best Location [2]	Energy at Best Location [3]	Best Location	Capacity Price [4]	Price Floor [5]	Capital at Best Location [1]	FOM at Best Location [2]	Energy at Best Location [3]	Best Location	Capacity Price [4]	Capital at Best Location [1]	FOM at Best Location [2]	Energy at Best Location [3]	Best Location	Capacity Price [4]	Capital at Best Location [1]	FOM at Best Location [2]	Energy at Best Location [3]	Best Location	Capacity Price [4]
MARKET-CLEARING CAPACITY PRICE (BASED ON NET CONE FOR A COMBINED CYCLE; $/KW-MONTH)																					
Current Trends Scenario																					
Conventional	7.7	2.5	6.2	Rest of CT	3.9	4.5	7.3	2.5	6.1	WC MA	3.7	7.3	2.5	6.7	WC MA	3.1	7.3	2.5	5.5	WC MA	4.3
DSM-Focus	7.7	2.5	6.1	Rest of CT	4.1	4.5	7.9	2.5	6.3	SW CT	4.1	7.3	2.5	6.5	WC MA	3.3	7.7	2.5	5.8	Rest of CT	4.4
Nuclear	-	-	-	-	-	4.5	-	-	-	-	-	7.3	2.5	6.2	WC MA	3.6	7.3	2.5	4.8	WC MA	5.0
Coal	-	-	-	-	-	4.5	-	-	-	-	-	7.3	2.5	6.2	WC MA	3.6	7.3	2.5	4.8	WC MA	5.0
Strict Climate Scenario																					
Conventional	7.7	2.5	5.8	Rest of CT	4.4	4.5	7.9	2.5	8.0	SW CT	2.4	7.3	2.5	7.0	WC MA	2.8	7.7	2.5	7.2	Rest of CT	3.0
DSM-Focus	7.7	2.5	5.7	Rest of CT	4.5	4.5	7.9	2.5	7.4	SW CT	2.9	7.3	2.5	7.6	WC MA	2.2	7.7	2.5	7.3	Rest of CT	2.9
Nuclear	-	-	-	-	-	4.5	-	-	-	-	-	7.9	2.5	7.4	SW CT	2.9	7.3	2.5	5.6	WC MA	4.2
Coal	-	-	-	-	-	4.5	-	-	-	-	-	7.9	2.5	7.4	SW CT	2.9	7.3	2.5	5.6	WC MA	4.2
High Fuel/Growth Scena																					
Conventional	8.7	2.7	7.1	SW CT	4.3	4.5	8.5	2.7	6.8	Rest of CT	4.4	8.7	2.7	6.5	SW CT	4.9	8.5	2.7	3.1	Rest of CT	8.1
DSM-Focus	8.5	2.7	6.6	Rest of CT	4.6	4.5	8.5	2.7	6.8	Rest of CT	4.4	8.7	2.7	7.3	SW CT	4.1	8.5	2.7	4.2	Rest of CT	7.0
Nuclear	-	-	-	-	-	4.5	-	-	-	-	-	8.0	2.7	5.4	WC MA	5.3	8.0	2.7	2.9	WC MA	7.8
Coal	-	-	-	-	-	4.5	-	-	-	-	-	8.0	2.7	5.4	WC MA	5.3	8.0	2.7	2.9	WC MA	7.8
Low Stress Scenario																					
Conventional	5.9	2.5	5.1	WC MA	3.2	4.5	5.9	2.5	5.0	WC MA	3.3	5.9	2.5	5.3	WC MA	3.1	6.2	2.5	4.4	Rest of CT	4.2
DSM-Focus	5.9	2.5	5.2	WC MA	3.1	4.5	5.9	2.5	5.1	WC MA	3.2	5.9	2.5	5.4	WC MA	2.9	6.2	2.5	4.1	Rest of CT	4.6
Nuclear	-	-	-	-	-	4.5	-	-	-	-	-	5.9	2.5	5.1	WC MA	3.2	5.9	2.5	3.0	WC MA	5.3
Coal	-	-	-	-	-	4.5	-	-	-	-	-	5.9	2.5	5.1	WC MA	3.2	5.9	2.5	3.0	WC MA	5.3
NET CONE FOR A COMBUSTION TURBINE ($/KW-MONTH)																					
Current Trends Scenario																					
Conventional	6.2	2.2	1.0	WC MA	7.4		6.2	2.2	1.5	WC MA	6.9	6.2	2.2	1.7	WC MA	6.7	6.2	2.2	0.9	WC MA	7.5
DSM-Focus	6.2	2.2	0.9	WC MA	7.5		6.2	2.2	1.3	WC MA	7.1	6.2	2.2	1.5	WC MA	6.9	6.2	2.2	1.0	WC MA	7.4
Nuclear	-	-	-	-	-		-	-	-	-	-	6.2	2.2	1.3	WC MA	7.1	6.2	2.2	0.9	WC MA	7.5
Coal	-	-	-	-	-		-	-	-	-	-	6.2	2.2	1.3	WC MA	7.1	6.2	2.2	0.9	WC MA	7.5
Strict Climate Scenario																					
Conventional	6.2	2.2	0.7	WC MA	7.7		6.2	2.2	1.4	WC MA	7.0	6.2	2.2	1.4	WC MA	7.0	6.2	2.2	1.3	WC MA	7.1
DSM-Focus	6.2	2.2	0.7	WC MA	7.7		6.2	2.2	1.2	WC MA	7.2	6.2	2.2	1.6	WC MA	6.9	6.2	2.2	1.3	WC MA	7.1
Nuclear	-	-	-	-	-		-	-	-	-	-	6.2	2.2	1.3	WC MA	7.1	6.2	2.2	1.0	WC MA	7.4
Coal	-	-	-	-	-		-	-	-	-	-	6.2	2.2	1.3	WC MA	7.1	6.2	2.2	1.0	WC MA	7.4
High Fuel/Growth Scena																					
Conventional	6.8	2.4	0.3	WC MA	8.9		6.8	2.4	0.8	WC MA	8.4	6.8	2.4	0.5	WC MA	8.7	6.8	2.4	0.2	WC MA	9.1
DSM-Focus	6.8	2.4	0.3	WC MA	8.9		6.8	2.4	0.7	WC MA	8.6	6.8	2.4	0.6	WC MA	8.7	6.8	2.4	0.2	WC MA	9.0
Nuclear	-	-	-	-	-		-	-	-	-	-	6.8	2.4	0.5	WC MA	8.8	6.8	2.4	0.2	WC MA	9.1
Coal	-	-	-	-	-		-	-	-	-	-	6.8	2.4	0.5	WC MA	8.8	6.8	2.4	0.2	WC MA	9.1
Low Stress Scenario																					
Conventional	4.9	2.2	0.8	WC MA	6.4		4.9	2.2	1.0	WC MA	6.1	4.9	2.2	0.8	WC MA	6.4	4.9	2.2	0.5	WC MA	6.7
DSM-Focus	4.9	2.2	0.9	WC MA	6.3		4.9	2.2	1.0	WC MA	6.2	4.9	2.2	0.8	WC MA	6.4	4.9	2.2	0.3	WC MA	6.9
Nuclear	-	-	-	-	-		-	-	-	-	-	4.9	2.2	0.7	WC MA	6.5	4.9	2.2	0.3	WC MA	6.8
Coal	-	-	-	-	-		-	-	-	-	-	4.9	2.2	0.7	WC MA	6.5	4.9	2.2	0.3	WC MA	6.8

Sources and Notes:

[1]: Future capital cost based on FERC testimony by John J. Reed; Prepared Direct Testimony of John J. Reed on Behalf of ISO New England Inc; Docket No. ER03-563-030; August 31, 2004; Pages 55-57. Adjusted for scenario-specific capital cost adders.

[2]: FOM values are based on EIA-906 data compiled by Global Energy Decisions, Inc., The Velocity Suite; ISO-New England RMR agreements; and FERC testimony by John J. Reed on behalf of ISO-New England. Adjusted for scenario-specific capital cost adders.

[3]: Includes unit average energy margin, plus spin and uplift payments. Adjusted for scenario-specific capital cost adders.

[4]: =[1] + [2] - [3].

[5]: The current price floor of $4.5/kW-Month is assumed to be in effect in 2011. The floor is assumed to diminish in later years, based on 60% of Net CONE.

A natural reaction to this contrarian finding of relatively low capacity prices is to question the energy price forecasts that drive the combined cycles' energy margins so high and their Net CONE so low. The prices can be explained based on the fundamentals of supply and demand, adjusted for unit outages and the non-commitment of units with long MUTs and high startup costs. In addition, as Table A.6 shows, modeled market heat rates are not very different from recent historical prices, although a small percentage increase in market heat rates can increase energy margins by a much larger percentage (based on the difference between market heat rate and a combined cycle's heat rate of 7,000).

c. FORWARD RESERVES MARKET

Absent new investment, the present shortage of fast-start capability capacity in Connecticut is likely to continue. 731 MW of existing[9] plus 220 MW of planned (100 MW Wallingford/Pierce, 80 MW Waterbury, 40 MW Cos Cob) would be insufficient to meet the requirement. We have assumed that the requirement would be set based on the capacity of Millstone 3, approximately 1,236 MW. (This is close to the 1,100-1,200 requirement projected by ISO-NE in its *2007 Regional System Plan*). We have assumed that 279 MW of new combustion turbines would be built in Connecticut in order to fully meet the requirement. This assumption is consistent with the recent recommendation of the DPUC to contract for 282 MW of fast-start capacity, as discussed in Docket No. 07-08-24, *DPUC Investigation of the Process and Criteria for use in Implementing Section 50 of Public Act 07-242 – Peaking Generation* (at p. 16).

If Connecticut's LFRM requirement is met but not exceeded, the LFRM price can be expected to remain at the price cap given by $14/kW-mo minus the capacity price. This amount, multiplied by a cost allocation factor is applied to Connecticut customers in evaluating rates under each scenario/solution combination. The cost allocation factor is assumed to be 45% to account for both Connecticut customers' share of the Connecticut LFRM costs (some of which are socialized across New England) and Connecticut's share of FRM costs from the rest of New England.

[9] *2007 Regional System Plan*, ISO New England, October 18, 2007, p. 44.

APPENDIX B: SCENARIO DEVELOPMENT

Long-range planning analyses must typically address substantial uncertainty regarding external factors. In order to understand the strengths and weaknesses of potential resource solutions, it is important to look at how they are affected by changes in these external factors. This can be done in several ways, including sensitivity analysis, scenario analysis, and Monte Carlo simulation.

In this study, we use scenario analysis, developing several internally consistent future scenarios against which the resource solutions are evaluated. Each scenario reflects a combination of particular values for the relevant external factors and is characterized by an underlying "driver" in combination with settings of other external factors that are consistent with this driver. The scenarios are designed so that the particular combinations of external factors are relatively likely (are internally consistent), and/or important (combinations that pose particular risks or opportunities to the resource solutions). To test the resource solutions under consideration and expose their strengths and weaknesses, the scenarios are intentionally relatively extreme, but not implausibly so. Together the scenarios depict a broad range of potential future conditions. However, the scenario set developed here is not intended to thoroughly cover the full range of potential outcomes.[1]

In contrast to scenario analysis, sensitivity analysis typically defines a "baseline" with all parameters set at nominal or expected levels, and varies one parameter at a time to evaluate the resource solutions.[2] Sensitivity analysis can of course be a valid and useful technique, but scenario analysis has some advantages here. Scenarios can better capture qualitatively different multi-dimensional futures, rather than examining only uni-dimensional variations from an

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[1] In some analyses, scenarios are used to span the full range of possible future outcomes, but that is not possible here, given the small number of scenarios that can be evaluated and the large number of potential combinations of external factors. Similarly, some scenario analyses weight scenarios with probabilities and calculate probability-weighted quantitative outcome measures. No attempt was made here to weight scenarios or average outcome measures. The goal of this study is to use scenarios to gain insights about the strengths and weaknesses of solutions, not to develop a single quantitative measure of their merit.

[2] The ISO-NE's "New England Electricity Scenario Analysis" is an example of a study that uses sensitivity analysis. Note that the ISO uses the term "scenario" to indicate what we call a "resource solution" – a way to meet resource needs. The ISO uses sensitivity analysis to examine different settings of external factors like fuel prices and CO_2 price.

assumed baseline. This avoids a "basecase" preference in which one particular setting of factors dominates the analysis.

Another approach to characterizing uncertainty is with Monte Carlo analysis, where many different combinations of external factors are generated randomly according to specified probability distributions, and resource solutions are evaluated against each combination. This would result in a probability distribution for each resource solution, and solutions could be compared based on their expected values and variances. However, a Monte Carlo approach would not be as informative here because it would embed our own subjective probability assessments and thereby obscure the dependence of resource solutions' relative values on very different future trajectories of external factors. It is important that this study illuminate for policy makers how the value of each resource solution depends on key external factors such as fuel prices, load growth, generation technology capital costs, and changes in environmental regulations, including climate legislation. Such factors are likely to vary not by a few percent along a well-behaved continuum, but by large jumps sometimes, and in ways that are interrelated. Hence, constructing a range of internally-consistent scenarios that address the range of plausible future trajectories of external factors is more informative in this context than Monte Carlo analysis.

One of the key steps in developing the scenarios for this study is to understand the relationship between the scenario drivers – economic growth, fuel price and CO_2 allowance price – and electricity prices and power demand. To create consistent relationship between these, we have considered the interaction between economic growth and electric load, and also the feedback effects by which fuel and CO_2 prices affect power price, which then also influences power demand. Different factors may have varying impact on energy demand vs. peak load, and we have captured this distinction as well.

Three interacting effects can influence energy and peak demand – the price of electricity, active demand-side management programs, and economic growth in the region. For the scenarios here, energy and peak forecasts are obtained by adjusting ISO New England's Base Case Load Forecast for these three effects:

1) Price Effect

One of the key parts of developing scenarios for the IRP is to understand the relationship between external drivers – fuel and CO_2 prices – and electricity prices and load. To approximate this relationship in developing scenarios, we used the fact that New England power prices are very closely linked to natural gas prices, and that CO_2 prices will affect power prices almost entirely through their effect on gas prices. In each scenario, we determined the approximate effect on retail power prices of changes in gas and CO_2 prices, assuming a 90% effect of gas prices on power prices, and accounting for the fact that wholesale power price is "diluted" by T&D charges in the retail price. Given this estimate of how power prices would change in a given scenario, we estimated the price effect on electric load using a price elasticity relationship.

Price elasticity for power is often estimated to be in the range of -0.8 to -1.0. (This is a long-run elasticity; short-run elasticities are much lower –around -0.1 to -0.2. Also, cross price elasticities between power and other energy sources are very small, and were ignored here.) This elasticity range is almost certainly too high in the context of large price changes, because of diminishing marginal effects. We assumed a long run energy price elasticity of -0.35 and short run energy price elasticity of -0.20, consistent with the Energy Information Administration's National Energy Modeling System (NEMS) elasticity estimates reported in Annual Energy Outlook 2003 (AEO2003). NEMS elasticities are more relevant in our context for two main reasons. First, these elasticity estimations are forward looking in the sense that they weigh potential long-run adjustments in the efficiency of equipment stock. Second, NEMS elasticities are estimated for a large price change which conforms to the case in our scenarios. We phase in short run elasticity response over three years starting in 2008, while the remaining effect (the difference between long run and short run) is phased in smoothly over 7 years starting in 2011. We also follow the same methodology to determine the price effect on peak load. Peak elasticity is smaller than energy elasticity (around half the magnitude) due to the limited substitutability of consumption during peak times. Accordingly, we assumed a long run peak price elasticity of -0.175 and short run peak price elasticity of -

0.10 for the effects on peak load, and phased in as for energy elasticity effects. This approach is used for all scenarios to adjust ISO-NE's Base Case Peak and Energy Forecasts for elasticity responses to scenario-specific fuel and CO_2 prices.

2) DSM Effect

The ISO-NE Base Case energy and peak forecasts are adjusted for DSM that is not included in the ISO-NE's forecasts. The "DSM Effect" represents how much lower the load will be relative to the ISO-NE's Base Case due to DSM activities. Two different levels of DSM (corresponding to DSM activities in the Resource Solutions) are studied; "Base DSM" is a component of all the Resource Solutions, and "Heavy DSM" characterizes additional DSM activities that occur in the DSM Focus resource solution. The nominal amount of DSM activities undertaken in either Base or Heavy DSM is the same across all scenarios, but the interaction with the price effect is taken into account to develop the resulting DSM response and scenario-specific loads. That is, the Resource Solution characterizes the amount of effort put into DSM activities, but given that, the quantity reduction in peak and energy that is actually achieved depends on the scenario.

3) Economic Growth Effect

Two of our scenarios do not start from the ISO-NE's Base Case energy and peak load forecasts, but instead work from the ISO's High Growth case (or a combination of that with the Base Case). For those scenarios, we define the "growth effect" to represent the deviation from the Base Case forecast in a given year.

After defining these effects for each of the scenarios, the next step is to adjust the ISO-NE's Base Case forecast by a combination of the three effects to arrive at the scenario load forecasts. For all scenarios except the Low-Stress Scenario, price effect and DSM effect work in the same direction to reduce the forecasts below ISO-NE's Base Case Forecast. These two effects compete to an extent (the price effect essentially "cannibalizes" the DSM effect), and to account for this we reduce the combined effect by half the magnitude of the smaller individual effect. In the Low Stress scenario, these two effects work in opposite directions and do not cannibalize one another, so they are simply summed. This combined impact of price and DSM effects is applied

in addition to the growth effect present to develop the scenario-specific peak and energy demand forecasts for the scenarios.

The primary dimensions on which scenarios are defined are:

A. Fuel prices - natural gas prices are of primary importance, but petroleum prices are also relevant.
B. Load growth
C. Cost of new generating capacity
D. Environmental policy – in particular, climate policy, represented by CO_2 price.

The table below summarizes the primary parameters that characterize each of the scenarios.

Table B.1: Scenario Summary

	A. Fuel Prices	B. Load Growth	C. Cost / Siting	D. Environment (CO_2 Price)
I. Current Trends	Gas: NYMEX w/ EIA growth rate Oil: NYMEX w/ EIA growth rate	ISO Base Case Load, adjusted for DSM (~2%, then 1.5% peak growth; ~1% energy growth)	nominal cost & siting parameters (see screening analysis)	RGGI 2011, 2013; Bingaman safety valve thereafter ($5 in 2011-13; ~$15 in 2018 to $26 in 2030)
II. Strict Climate	Gas price ~10% higher, due to higher gas demand from electric gen (partially offset by non-electric gas use). Oil same as Current Trends.	Below Current Trends Case, due to higher power price (from CO_2 price, gas price), though based on ISO Base Case Load.	nominal cost & siting parameters	Strict climate: 2x EPA Assessment of S.280, starting 2012 (RGGI pre-2012) ($26/t 2012; $34/t 2018; $60/t 2030)
III. High Fuel / Growth	Gas ~$11/MMBtu (.85 parity to $85/bbl crude, 1.7*Ref gas price) FO_2, FO_6 similar to Ref prices (maintain relative rel'n to crude)	Substantially below Current Trends Case due to higher power price (from CO_2 price and gas price) despite being based on high growth case.	Higher costs; additional 10% above Ref Case on Capital costs, FOM, VOM	30% over Current Trends prices starting in 2014 ($16 in 2014; $20 in 2018; $35 in 2030)
IV. Low Stress	HH gas at ~$5; Crude at ~$40 (in 2012, 2008$)	Based on economic growth only slightly higher than nominal, but load is much higher than Current Trends due to lower power prices.	low cost / easy siting Reduce Capital costs by ~20% vs Current Trends Case (all techs)	Same as Current Trends Case: RGGI/Bingaman

I. SCENARIO DESCRIPTIONS

A. Current Trends Scenario

The Current Trends scenario is based on a continuation of current conditions and expectations. It is specified as follows.

i. Fuel Prices

a. Henry Hub natural gas prices are from NYMEX Henry Hub Futures as of 9/27/2007, with data available October 2007 through December 2012. After 2012, prices are extrapolated through 2030 using EIA annual growth rates for natural gas prices (from the 2007 Annual Energy Outlook). Delivered natural gas prices are obtained by adding a New England basis

differential; this adder to Henry Hub prices is differentiated monthly but is assumed to remain constant over years, with an annual average of $1/MMBtu.

b. Residual Fuel Oil (FO_6) prices are forecast for October 01, 2007 through December 01, 2012 based on NYMEX crude oil futures prices, adjusted based on the historical relationship between crude and FO_6 (from a simple linear regression). After 2012, FO_6 prices are extrapolated to 2030 using EIA annual growth rates for FO_6.

c. Distillate Fuel Oil (FO_2) prices are NYMEX Heating Oil futures from October 2007 through September 2010. Prices are extrapolated beyond 2010 to 2030 using EIA annual growth rates for FO_2.

ii. Load

a. Growth Effect: No additional growth effects; energy and peak load are based on the ISO-NE Base Case forecast. ISO-NE forecasts are only available from 2007 through 2016. Therefore, energy and peak load are extrapolated through 2030 by using the 2015-2016 forecast energy growth rate (approximately 1%) and peak load growth rate (approximately 1.5%).

b. DSM Effect: Base and Heavy DSM efforts have their nominal specified effects, as described in Appendix D.

c. Price Effect: No additional price effect, since prices are assumed to be at nominal levels. Price effects for other scenarios are defined relative to the Current Trends Scenario.

iii. Cost and Siting

a. Costs for new generation are as described in Appendix C. This reflects Connecticut locational construction costs, as well as

the recent substantial increase in capital costs of generating technologies (up by roughly 25-35% over typical cost estimates from just a few years ago).

iv. Environmental Regulations (CO_2)

a. Starting in 2010 when RGGI comes into effect, CO_2 prices are based on RGGI (approximately \$5/t CO_2). Beginning in 2014 and continuing through 2030, prices are based on the safety valve price in the Bingaman-Specter Low Carbon Economy Act of 2007. The safety valve begins at \$12/t (in 2012\$) and grows at 5% in real terms. This yields approximately \$12/t in 2014, \$16/t in 2020 and \$26/t in 2030 (all in 2008\$). For comparison, in its Scenario Planning exercise, the ISO-NE assumed a CO_2 price of \$20/t in its Base Case. Allowance prices for SO_2, NO_X and mercury are based on EIA forecasts (these are not varied across other scenarios, as they are a relatively small cost component).

B. Strict Climate Scenario

This scenario is driven primarily by strict climate policy, based loosely on several of the more stringent legislative proposals that have been put forward recently (*e.g.*, 70% reduction in GHG emissions by 2050). The primary implication for the power sector is a substantially higher price of CO_2. The high CO_2 price causes some dispatch switching (from coal to gas) and a shift toward gas-fired generation for capacity additions; this increased in gas demand from the electric sector is partially offset by a decrease in non-electric use of gas, and the resulting moderate increase in gas demand causes natural gas commodity prices to increase somewhat. The high CO_2 price and higher gas price are reflected in higher electricity prices, which cause a reduction in load relative to the Current Trends Scenario.

i. Fuel Prices

a. Henry Hub natural gas prices are 10% above the Current Trends scenario due to increased gas demand. Higher gas demand for electric generation is partially offset by decreased non-electric gas consumption (in response to the increase in effective gas prices caused by the higher CO_2 price). The basis differential to New England is unchanged from the Current Trends scenario.

b. FO_2 and FO_6 prices are the same as the Current Trends Scenario.

ii. Load

a. Growth Effect: No growth effects as energy and peak is assumed to grow at the same rate as ISO-NE's Base Case energy and peak forecasts.

b. DSM Effect: DSM effect interacts with price effect as described in the introduction to this Appendix.

c. Price Effect: ISO-NE Base Case forecasts for energy and peak are adjusted for the impact of higher electricity prices, which are driven by higher gas and CO_2 prices. In addition to the 10% increase in the cost of gas itself, the higher CO_2 price will increase the effective natural gas price by an additional 14% (compared to the Current Trends scenario). This resulting 24% increase in effective gas prices will cause a 14% increase in delivered power prices. This will induce:

- Energy decreases by 5%, relative to ISO-NE Base Case energy forecast in 2018. The short-term response, a 3% decrease in energy, is phased in smoothly over the first 3 years through 2011 and the remaining 2% decrease (long-term response) is phased in over the following 7 years through 2018. The percentage difference in energy relative to the Base Case is assumed to remain constant beyond 2018.

- Peak decreases by 2.5%, relative to ISO-NE Base Case peak forecast in 2018. The 1.5% short-term decrease in the peak is phased in smoothly over the first 3 years through 2011 and the remaining 1% decrease (long-term) is phased in over the following 7 years through 2018. The percentage difference in peak relative to the Base Case is assumed to remain constant beyond 2018.

iii. Cost and Siting

a. Same as the Current Trends Scenario.

iv. Environmental Regulations (CO_2)

a. For 2010 and 2011, CO_2 prices are based on RGGI (approximately \$5/t CO_2). Starting in 2012, CO_2 prices are substantially higher than the Current Trends scenario, due to strict federal climate policy coming into effect then. The effect of such a strict climate policy on CO_2 price is based on the EPA assessment of S.280, the Lieberman Climate Stewardship and Innovation Act of 2007. EPA's estimated CO_2 prices were doubled for this scenario; the EPA analysis found that CO_2 prices were very sensitive to the amount of offsets allowed, and that under the same bill but without any offsets, the price would approximately triple. A price of double the EPA "Lower Nuclear Power Generation" case estimate is reasonably representative of a strict but credible climate policy. Other analyses suggest that prices of around this level are probably necessary to prompt a significant change in CO_2 emissions, particularly from the power sector (*e.g.*, to cause dispatch switching from coal to gas generators, and to prompt the construction of lower-CO_2 new generation). This leads to CO_2 prices of \$26/t in 2012; \$37/t in 2020 and \$60/t in 2030. For comparison, in its Scenario Planning exercise, the ISO-NE used a CO_2 price of \$40/t in its high carbon price sensitivity

case. The current CO_2 allowance price in the EU ETS is €22, or \$32/t CO_2.

v. High Fuel/ Growth Scenario

This scenario is characterized by high (regional or global) economic growth, in combination with substantially higher natural gas prices. High natural gas prices are driven at least in part by high U.S. gas demand (and strong global demand for LNG, which prevents it from holding domestic prices down). Petroleum prices are somewhat higher than the Current Trends scenario. *E.g.*, FO_2 prices are 30% higher on average over the horizon; FO_6 prices average 20% higher. Electric load growth in this scenario is affected by two strong but opposing factors – high economic growth tends to increase load, while higher fuel and CO_2 prices push up power prices, which tends to decrease load. On balance (and perhaps somewhat surprisingly), electric energy demand in this case is slightly lower than under the Current Trends scenario, though peak load is higher (peak demand is less sensitive to the price of power).

vi. Fuel Prices

a. Currently, gas is priced at roughly 60% parity with crude on a Btu basis, substantially below the historical pricing relationship of about 85% parity. High economic growth, which is assumed in this scenario, will lead to high gas demand, which could cause gas to return to its relative pricing relationship with oil. A 70% increase in gas price from the Current Trends scenario puts gas at 85% pricing parity with crude at \$85/bbl (2008\$). Note that current futures price for 2011 – \$80/bbl (2008\$) – is somewhat above the \$67/bbl crude futures price that prevailed in September when fuel price data was sampled this study. Gas price in this scenario is defined as 170% of the Current Trends gas price. These are Henry Hub prices; since the New England basis differential is assumed to be unchanged, the delivered

price increases by about 60% relative to the Current Trends delivered price.

b. Crude prices in this scenario are assumed to maintain this 85% parity relationship with gas prices; i.e., gas and crude prices move together. This differs from other scenarios but is consistent with gas and oil having a stable long-term pricing relationship. FO_2 prices are estimated in relation to this crude price trajectory, based on the EIA forecast of the relationship between crude and FO_2. FO_6 prices are forecasted using the estimated relationship between historic crude oil and FO_6 prices.

vii. Load

a. Growth Effect

- Under this scenario, the growth effect on energy is based on the ISO-NE's "High Case" energy forecast which reflects strong economic growth. The effect in year 2018 is assumed to remain constant through 2030.
- The growth effect on peak load is based on the ISO-NE's "High Case" peak load forecast. The effect in year 2018 is assumed to remain constant through 2030.

b. DSM Effect: DSM effect interacts with price effect as described in the introduction to this Appendix.

c. Price Effect: ISO-NE Base Case forecasts for energy and peak are adjusted for the impact of 36% increase in power price that was prompted by a 67% increase in gas prices (due to higher gas and CO_2 prices relative to the Current Trends Scenario). This results in:

- A 13% decrease in energy demand relative ISO-NE's Base Case forecast in 2018. The short-term effect, 7.5%, is phased in the first 3 years through 2011, and the remaining (long-term) 5.5% decrease is phased in over 7 years through 2018. Beyond 2018, this 13% decrease in energy demand relative to the ISO-NE Base Case is maintained.

- A 6.5% decrease in peak relative ISO-NE's Base Case forecast in 2018. The short-term effect, 3.5%, is phased in the first 3 years through 2011, and the remaining (long-term) 3% decrease is phased in over 7 years through 2018. Beyond 2018, this 6.5% decrease in peak is maintained.

viii. Cost and Siting

a. Costs of new generation (capital costs, FOM, and VOM) are increased by an additional 10% over Current Trends values to reflect higher costs (*e.g.*, for labor and materials) in a high economic growth case.

ix. Environmental Regulations (CO_2)

a. CO_2 prices are based on RGGI from 2010 until 2014. Beginning in 2014 and continuing through 2030, prices are 30% higher than the Current Trends scenario CO_2 prices, due to the additional demand for CO_2 allowances created by high economic growth.

C. Low Stress Scenario

Historically, periods of high prices are often followed by a return to earlier, lower price trends. The Low Stress scenario reflects a return to somewhat lower fuel and generator costs, reversing some (though not necessarily all) of these recent price increases. Slightly higher economic growth, combined with substantially lower power prices, results in both peak and energy load that are much higher than in the Current Trends Scenario.

i. Fuel Prices

a. All fuel prices are 40% below their corresponding Current Trends values. Both oil and gas prices fall so that their current relationship is maintained. For natural gas, the New England basis differential is assumed to be unchanged, so the

proportional effect on delivered gas prices is smaller (about 35%).

ii. Load

a. Growth Effect

- This scenario assumes an energy load that is the midway between ISO-NE's High Case and Base Case energy forecasts.[3] The growth effect in year 2018 is assumed to remain the same beyond 2018.
- Peak load is midway between ISO-NE's High Case and Base Case peak forecasts. The growth effect in year 2018 is assumed to remain the same beyond 2018.

b. DSM Effect: DSM effect interacts with price effect as described in the introduction to this Appendix.

c. Price Effect: ISO-NE Base Case forecasts for energy and peak are adjusted for the impact of lower gas prices on load. The 35% decrease in delivered gas price will cause a 20% decrease in delivered power prices. This leads to:

- A 7% increase in energy demand relative ISO-NE's Base Case forecast in 2018. The short-term effect, 4%, is phased in the first 3 years through 2011, and the remaining (long-term) 3.3% increase is phased in over 7 years through 2018. Beyond 2018, this 7% increase in energy demand relative to the ISO-NE Base Case is maintained.
- A 3.5% increase in peak relative ISO-NE's Base Case forecast in 2018. The short-term effect, 2%, is phased in the first 3 years through 2011, and the remaining (long-term) 1.5% increase is phased in over 7 years through 2018. Beyond 2018, this 3.5% increase in peak is maintained.

iii. Cost and Siting

a. Generator costs are lower than in the Current Trends scenario, reflecting a reversal of at least some of the recent increases in construction costs. Capital costs are reduced by 20% relative

[3] This assumption is consistent with a scenario in which low fuel prices are stimulating moderately higher economic growth. However, economic growth is assumed to be less extreme than in the ISO-NE's High Case, since it is less likely that fuel prices would remain low if the economy were growing at this high rate. This logic affects both peak and energy demand.

to the Current Trends scenario for all technologies. (FOM and VOM are unchanged from Current Trends levels.)

iv. Environmental Regulations (CO_2)

a. Same as the Current Trends Scenario.

II. GRAPHICAL DEPICTIONS

Fuel prices, CO_2 prices and loads (peak and energy) of the four scenarios are depicted graphically below.

Figure B.1: Current Trends Scenario – Fuel Prices

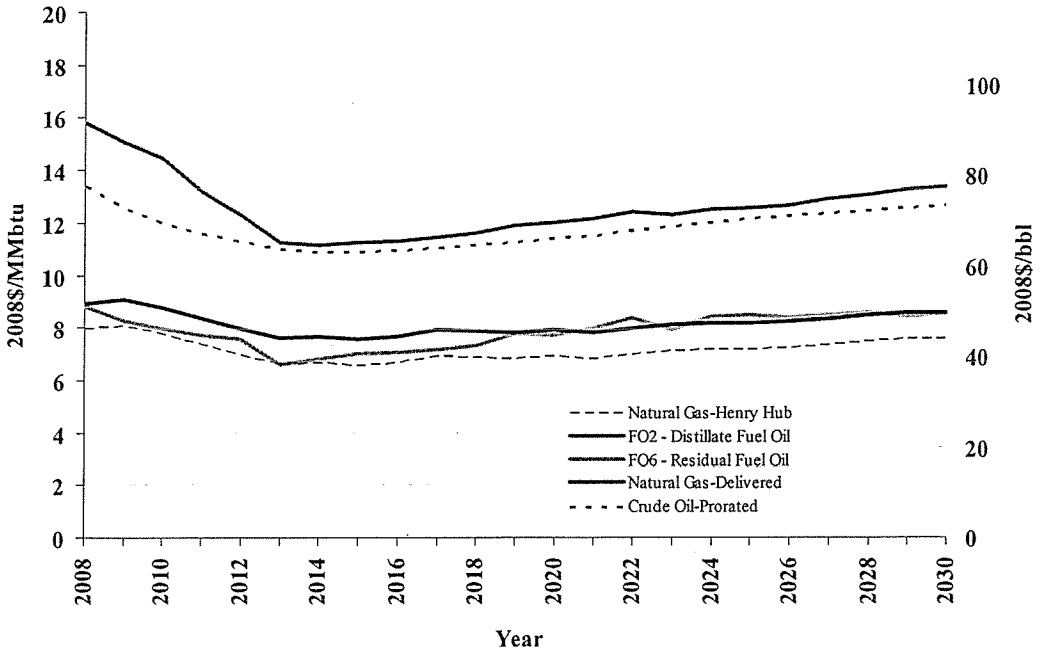


Figure B.2: Strict Climate Scenario – Fuel Prices

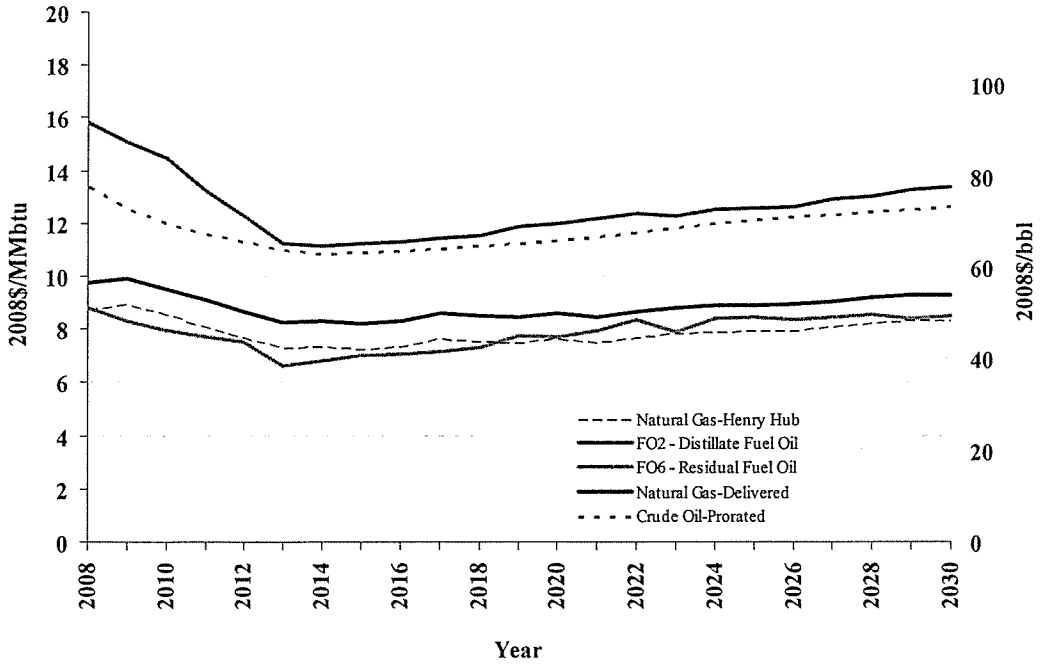


Figure B.3: High Growth/Fuel Scenario – Fuel Prices

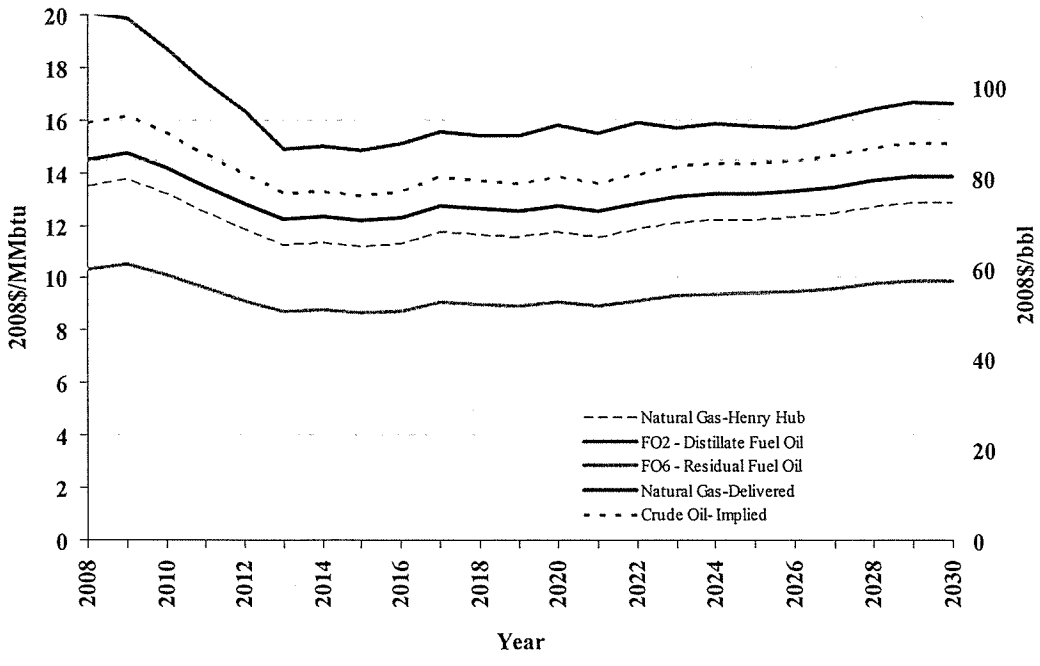


Figure B.4: Low Stress Scenario – Fuel Prices

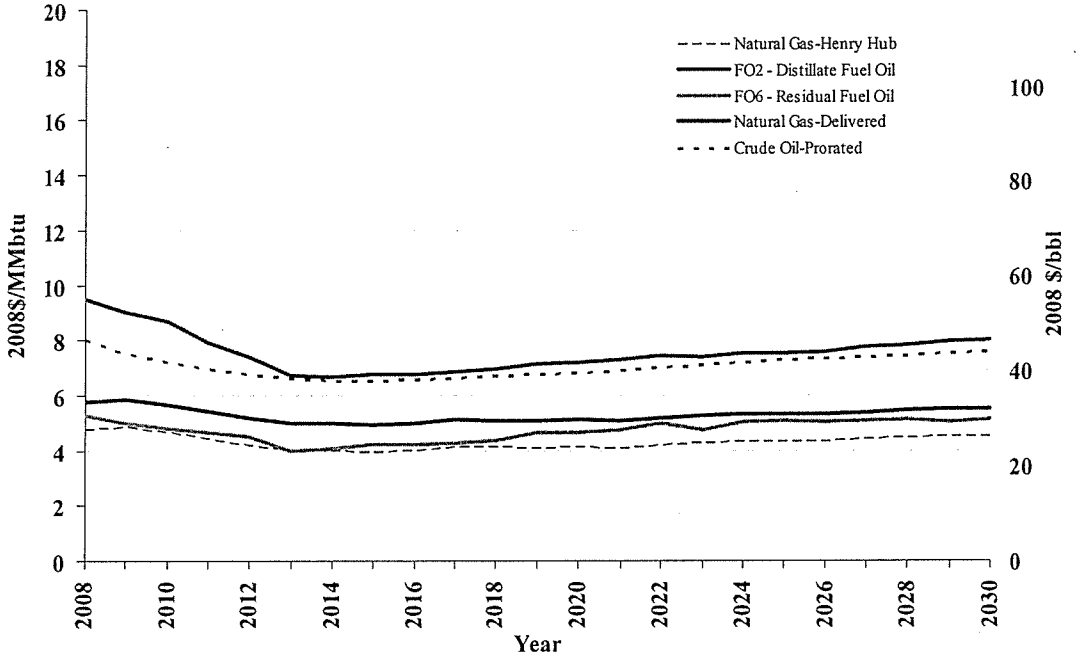


Figure B.5: Delivered Natural Gas Prices (All Scenarios)

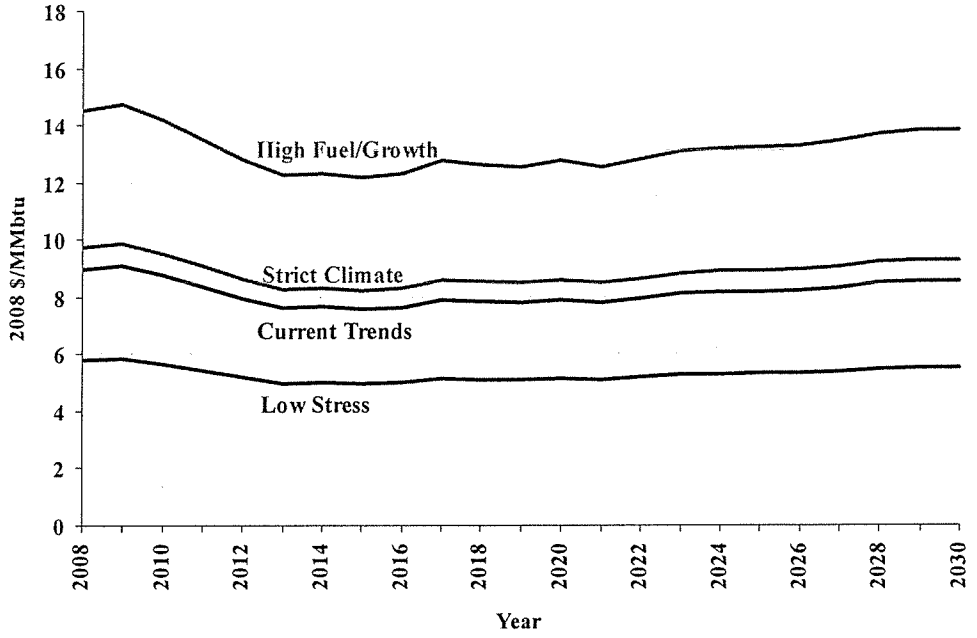


Figure B.6: CO_2 Allowance Prices (All Scenarios)

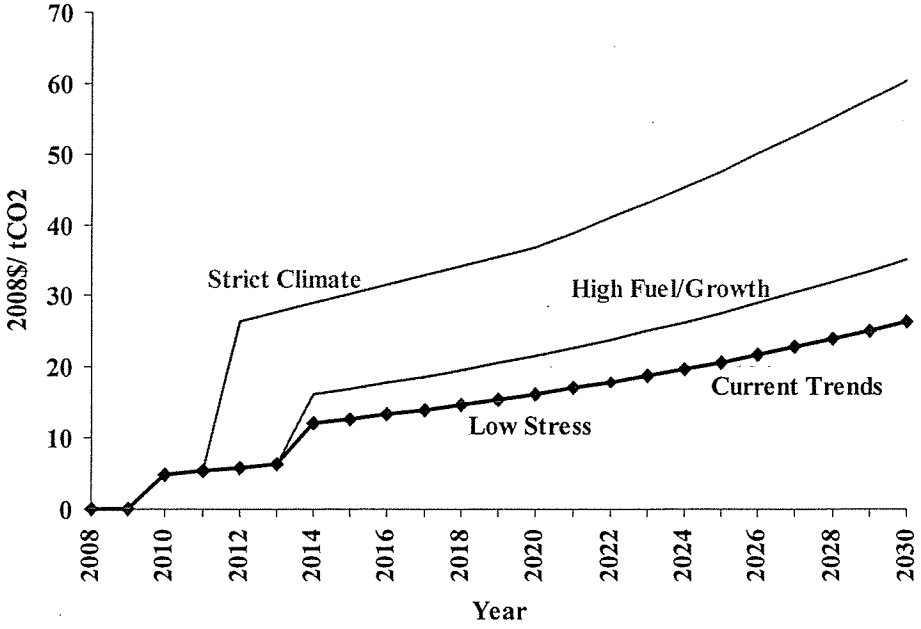


Figure B.7: Energy Profile (All Scenarios; Conventional and DSM-Focus Solutions)

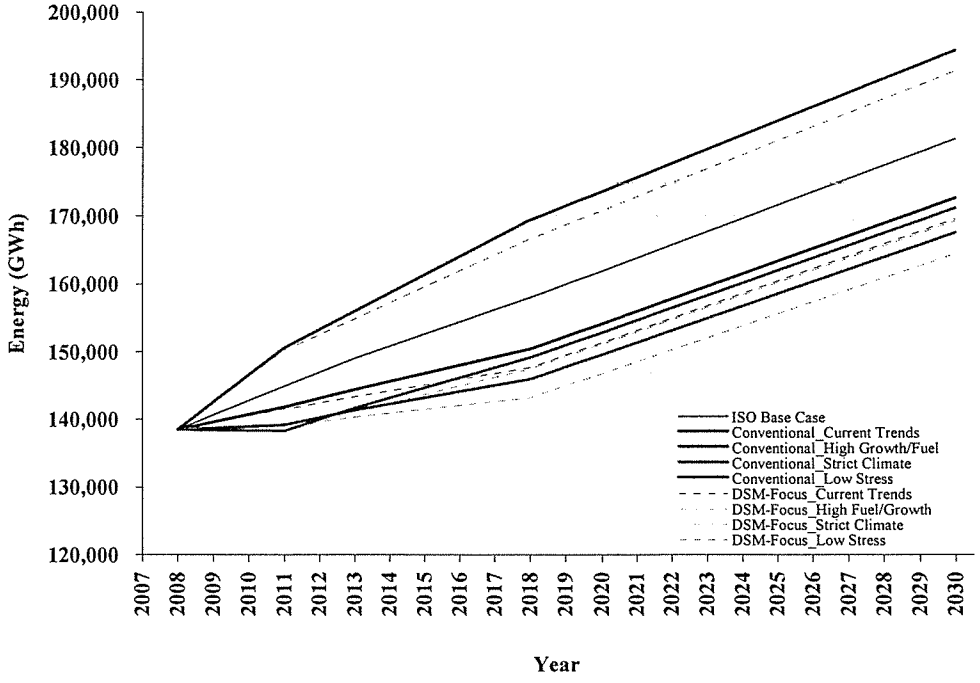
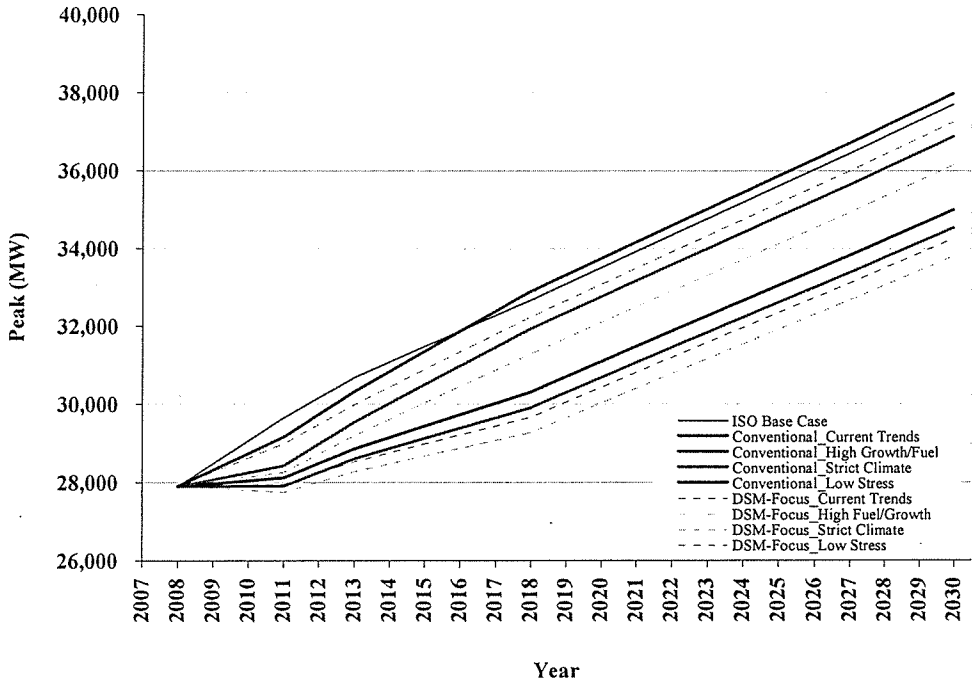


Figure B.8: Peak Profile (All Scenarios; Conventional and DSM-Focus Solutions)



APPENDIX C: GENERATION SUPPLY CHARACTERIZATION

I. CONVENTIONAL GAS-FIRED TECHNOLOGY

The characterization of conventional gas-fired generating technology – combustion turbines (CTs) and combined cycle generators (CCs) – is based on the review of numerous sources for the cost and performance of these technologies. This includes the testimony of John Reed on behalf of ISO-NE in the development of the ISO's locational capacity market. Mr. Reed performed a detailed assessment of the fixed costs of combustion turbine capacity installed at different locations on the ISO-NE grid; this locational cost information is particularly important in the context of the IRP. We updated Mr. Reed's assumptions to current values, supplemented variable operating cost information and adjusted for technological evolution over time.

Since combined cycle technology is very similar to combustion turbine technology, we used the CT costs described above as a basis for estimating combined cycle costs. Combined cycle installed costs were assumed to be 150% of CT installed costs, consistent with other sources (different construction schedules cause overnight costs to have a slightly different relationship). These costs were then adjusted for technological evolution over time. Combined cycle operating costs were also based on an adjustment to combustion turbine operating costs.

Table C.1 presents a high-level characterization of CT and CC technology cost and performance. The values in this table represent capacity located within Connecticut but outside Southwest Connecticut. Values for Southwest Connecticut and for other locations in New England were also developed and used for the simulation analyses. The cost parameters reflect the Current Trends scenario; in other scenarios these cost parameters take on different values.[1]

[1] Table C.1 shows heat rates of 6,508 and 9241 Btu/kWh for CCs and CTs, respectively, which reflect full-load heat rates at ideal conditions. Heat rates of 7,000 and 10,200 Btu/kWh, respectively, were used in the simulation analyses. The simulation produces capacity factors that differ from the capacity factors shown in Table C.1 for screening purposes. (However, the cost parameters shown in Table C.1 were used in our analysis of capacity prices.)

Table C.1: Gas-Fired Generating Technology Characteristics (2015 Online Date)

Parameter	Units	Combustion Turbine	Combined Cycle
Overnight Cost	(2008$/kW)	598	869
Fixed O&M	(2008$/kWyr)	26.7	29.7
Variable O&M	(2008$/MWh)	3.2	1.4
Economic Life	(Years)	20	40
Capital Charge Rate	(%)	13.1%	10.7%
Fuel Type	(type)	Gas	Gas
Heat Rate	(Btu/kWh)	9,241	6,508
CO2 Emissions	(tons/MWh)	0.50	0.35
Assumed Capacity Factor	(%)	20%	85%

Notes: Costs reflect generation sited in Connecticut. Emissions are in metric tonnes.

II. Baseload Generation Characterization and Screening

The Baseload Generation resource solution examines the addition of a significant amount of baseload generating capacity (i.e., capacity with high fixed cost but relatively low operating cost) within Connecticut. There are several candidate baseload generating technologies to consider, including nuclear and several versions of coal-fired generators. The question of which of these potential baseload technologies to consider is addressed first with a screening analysis, which calculates the all-in cost (the levelized lifecycle cost) of the different technologies.

A number of data sources were considered for the capital and operating costs and performance parameters of several potential baseload technologies, including:

- Pulverized coal (supercritical)
- Pulverized coal with carbon capture and sequestration (CCS)
- Integrated gasification combined cycle (IGCC)
- IGCC with CCS
- Advanced Nuclear

Estimating the cost and performance of generating technologies is complicated by the fact that the industry has little or no recent experience building many of the potential

technologies (*e.g.*, advanced nuclear, carbon sequestration). Further, even conventional technologies have experienced major increases in capital costs in the past several years, making it difficult to estimate costs even for well-understood technologies. In addition, regional cost differences mean that a generic technology cost comparison may not be appropriate for Connecticut. For example, the cost of building new generation in Connecticut is significantly above U.S. average construction costs, as are delivered fuel costs and O&M costs.

Many of the cost assumptions for this analysis are based on the recent study by the National Energy Technology Laboratory (NETL) on fossil generation costs, though numerous other sources were also reviewed, including EIA technology projections, MIT's Future of Coal and Future of Nuclear studies, ISO New England's recent Scenario Analysis study, and others. Because the NETL study is recent, thorough and done consistently across most of the relevant technologies, it is a useful source here. Capital costs were increased to account for recent cost increases, and further adjusted to reflect regional cost differences for Connecticut. Similarly, operating costs are adjusted to reflect a Connecticut location. Fuel and emissions costs used in the screening analysis are based on levelized equivalents to the fuel and emission cost trajectories from the four scenarios. All-in costs are evaluated at 85% capacity factor for all fossil technologies, and 90% for nuclear. Although different technologies might have capacity factors that differ slightly from these assumptions, the differences would be modest on the New England grid, and subsequent sensitivity analyses showed that the conclusions of the screening analysis would not change in light of this.

Table C.2 presents a high-level characterization of cost and performance parameters for baseload technologies located within Connecticut, outside Southwest Connecticut. Again, these cost parameters reflect the Current Trends scenario; they take on different values in other scenarios. To facilitate a high-level comparison, we also include here the parameters of a gas-fired combined cycle plant, both with and without CCS.

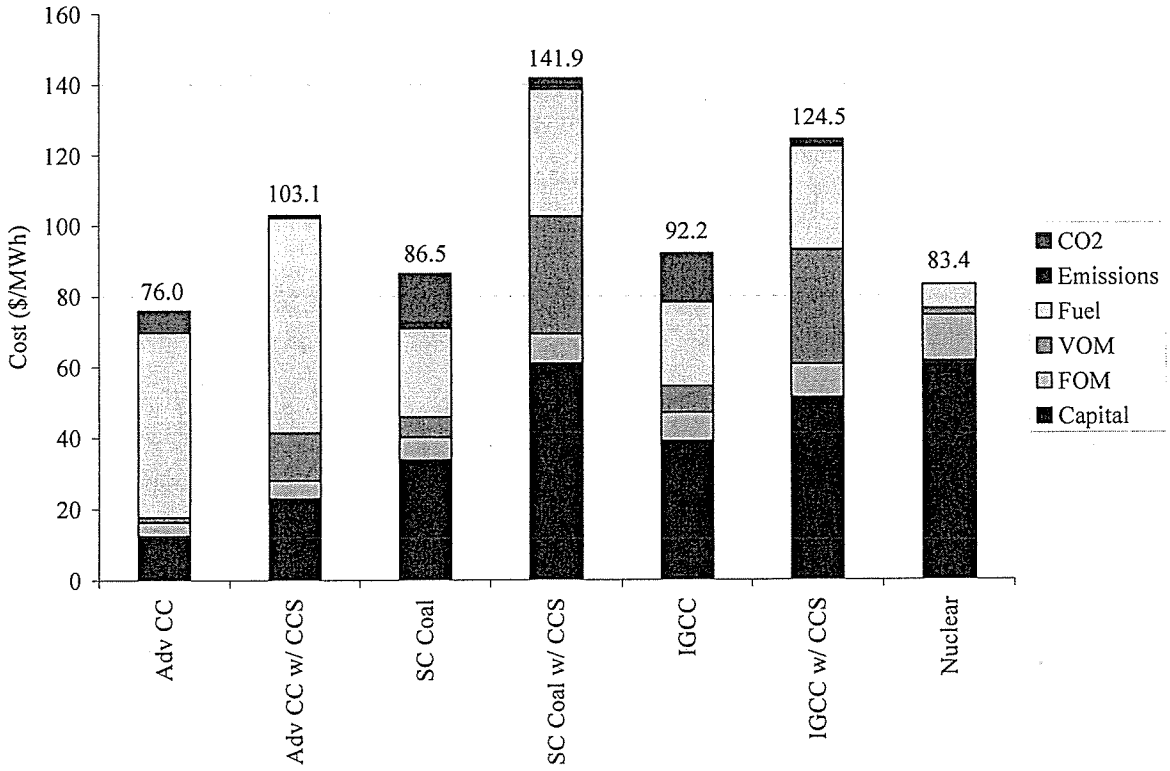
Table C.2: Baseload Generating Technology Characteristics (2015 Online Date)

Parameter	Units	Combined Cycle	Combined Cycle w/ CCS	Supercritical Coal	Supercritical Coal w/ CCS	IGCC	IGCC w/ CCS	Advanced Nuclear
Overnight Cost	(2008$/kW)	869	1,558	2,214	4,037	2,567	3,387	4,038
Fixed O&M	(2008$/kWyr)	29.7	37.1	47.3	62.0	59.2	70.3	102.9
Variable O&M	(2008$/MWh)	1.4	13.6	5.8	33.4	7.6	32.5	1.8
Economic Life	(Years)	40	40	40	40	40	40	40
Capital Charge Rate	(%)	10.7%	10.7%	11.1%	11.1%	11.1%	11.1%	11.9%
Fuel Type	(type)	Gas	Gas	Coal	Coal	Coal	Coal	Nuclear
Heat Rate	(Btu/kWh)	6,508	7,609	8,620	12,367	8,144	10,039	10,280
CO2 Emissions	(tons/MWh)	0.35	0.04	0.79	0.11	0.78	0.10	0.00
Assumed Capacity Factor	(%)	85%	85%	85%	85%	85%	85%	90%

Notes: Costs reflect generation sited in Connecticut. Emissions are in metric tonnes. CCS is carbon capture and sequestration. Technologies with CCS assume offshore sequestration.

Figure C.1 below illustrates the result of the initial all-in cost analysis, using cost and price parameters (construction and O&M costs, as well as emissions prices and CO_2 price) that reflect the environment of the Current Trends scenario. To facilitate an approximate high-level comparison in the screening analysis, we included a gas-fired CC, both with and without CCS. Note that a screening analysis like this may not account accurately for system interactions, so the comparison with a gas CC may be incomplete. For a proper comparison of gas-fired versus baseload capacity, a system simulation is necessary; this was done in the simulation analyses comparing the Conventional vs. Baseload resource solutions.

Figure C.1: Levelized Electricity Cost for Baseload Technologies (Current Trends parameters)



The same technologies can be evaluated against the parameters that reflect each of the other scenarios as well, as is illustrated in Figure C.2. The different scenarios have different fuel and CO_2 prices, as well as different technology costs, and all these differences may affect the comparison. Figure C.3 following shows the same information as Figure C.2, but groups results by scenario rather than by technology, which makes some effects easier to observe.

Figure C.2: Levelized Electricity Cost for Baseload Technologies (All Scenarios) – by Technology

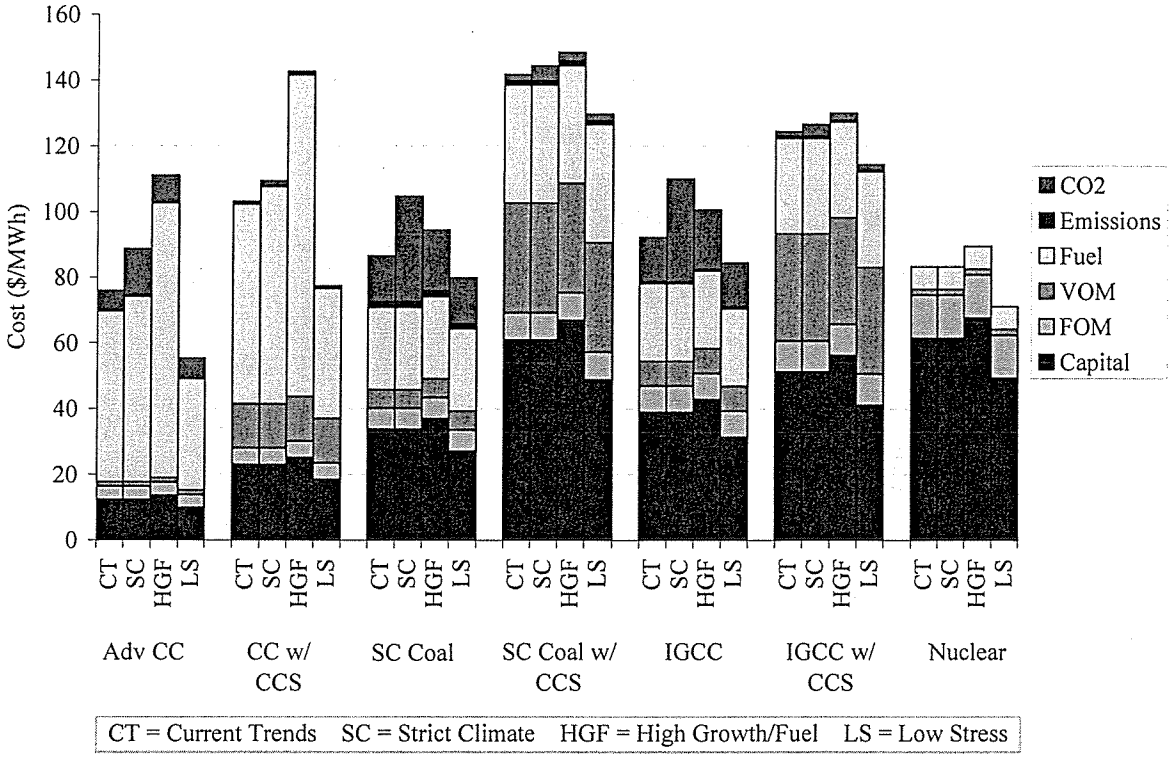
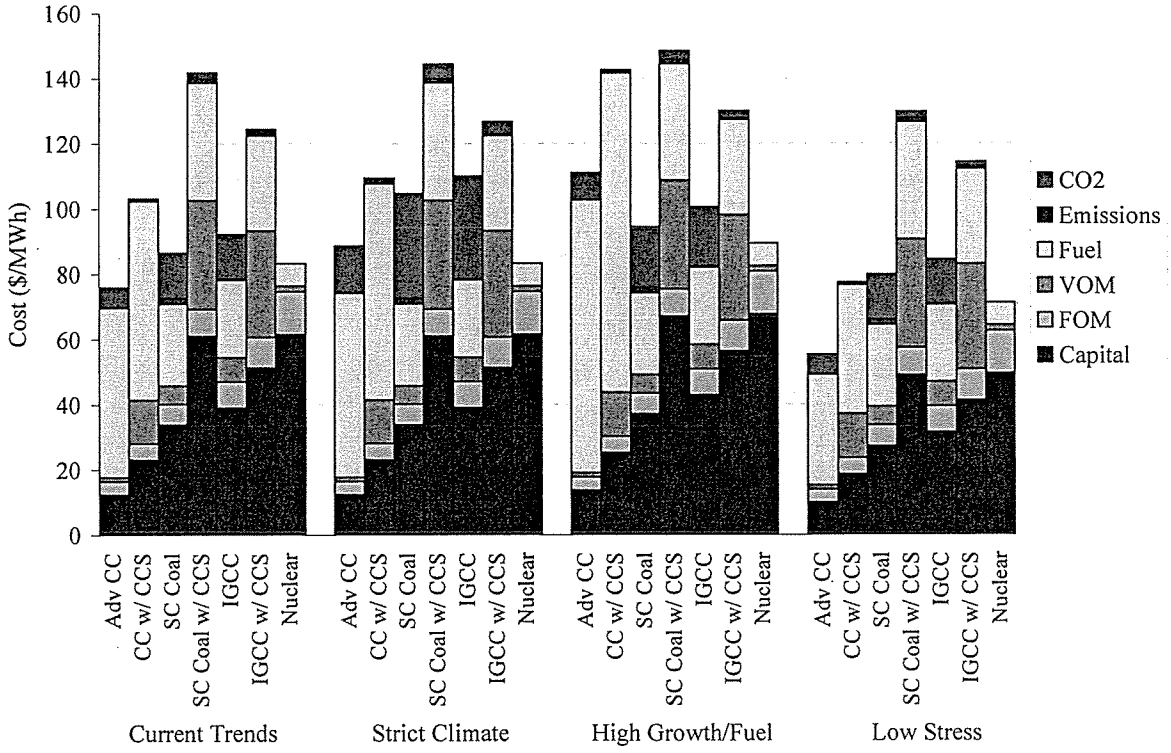


Figure C.3: Levelized Electricity Cost for Baseload Technologies (All Scenarios) – by Scenario



Discussion of Screening Results

The results illustrated above display several effects. First, compare the various coal technologies - supercritical coal and IGCC with and without CCS. The screening results suggest that it would make most sense to consider either a supercritical coal plant without CCS, or IGCC with CCS, but not the alternative combinations (SC Coal w/ CCS or IGCC without CCS). Figure C.1 shows that SC Coal is less costly than IGCC without CCS, but IGCC w/ CCS is less costly than SC Coal w/ CCS. That is, by itself, SC Coal is the more economical technology, but the incremental costs of CCS are larger on SC coal so that the economics reverse with CCS. This same observation applies in the other scenarios in Figures C.2 and C.3; the primary factors that change across scenarios are capital costs and CO_2 emissions costs, and these do not alter the relationships above. We did not explicitly analyze here the option to add CCS to a coal plant originally developed without it (what is sometimes referred to as a "capture ready" plant). Other analyses suggest that

this option is unlikely to be attractive, in part because an IGCC plant must be configured differently to operate with CCS, so that adding CCS after the fact is much more costly.

The screening analysis suggests coal with carbon sequestration is unlikely to be a viable option in New England. I.e., SC Coal is more attractive than IGCC w/ CCS. This is in part because it appears that New England does not have favorable geology for carbon sequestration. This makes it necessary to do offshore (undersea) sequestration with attendant higher transportation, storage and monitoring costs. These additional costs appear as components of Variable O&M (VOM) in the graphs above. Even if lower-cost onshore CCS was feasible, CCS would likely still be unattractive in Connecticut. New England has higher regional construction costs and higher coal prices than other regions. Higher construction costs disadvantage capital-intensive technologies like IGCC w/ CCS, and combined with higher coal costs, make it more difficult to compete with gas-fired technologies. It could well be that under strict climate legislation, IGCC w/ CCS becomes economical in many regions of the country, but not in New England. Under federal climate legislation, CO_2 prices would be uniform nationwide, but higher Connecticut capital costs would still tip the economic balance away from a capital-intensive technology that sequesters carbon to avoid its price. Higher coal prices and higher sequestration costs would reinforce this effect.

As an aside, we note that based on this screening analysis, adding CCS capability to a gas-fired combined cycle plant appears economically unattractive. Although the incremental capital costs associated with CCS are smaller than for coal, they are not justified by the savings in CO_2 emissions costs avoided (a conventional gas CC emits only about half as much CO_2 as a coal plant). The lower efficiency and higher operating costs of a CC with CCS further reinforces this effect.

This leaves the SC Coal and Nuclear options remaining as potentially attractive baseload generation options. There are substantial differences in the uncertainties that affect these two technologies. The economics of a coal plant are exposed to very uncertain, potentially high CO_2 costs. The economics of nuclear generation are subject to large

capital cost uncertainties, further complicated by other factors not modeled explicitly here, but nonetheless important – potential siting difficulties, concerns about nuclear proliferation and spent fuel disposal, etc. While Figure C.2 above appears to show that nuclear involves less cost uncertainty, this is simply because the scenarios do not reflect the uncertainty in nuclear construction costs (since it does not interact with other scenario variables, this uncertainty can be considered separately).

Because this screening analysis does not show a clear preference for either SC Coal or Nuclear, we evaluate both as baseload alternatives in the simulation analyses. On the New England grid, where the large majority of capacity has much higher variable cost than either nuclear or coal, these two baseload technologies will operate in essentially the same way. This is in contrast with some other regions, where a coal plant may operate at a lower capacity factor because of large amounts of low-cost generation.

This screening analysis also suggests that gas-fired combined cycle technology is likely to be attractive, but since that is being considered as a separate resource strategy and modeled with full system simulations, we do not attempt to draw conclusions about the relative merits of gas-fired versus baseload technologies from this screening analysis.

III. Renewable Generation Characterization

The discussion of renewable energy sources is contained in Appendix E: Renewable Energy.

IV. Sources

The following sources were reviewed in characterizing supply side generating technologies.

"Annual Energy Outlook 2007." Energy Information Administration. February, 2007. http://www.eia.doe.gov/oiaf/archive/aeo07/index.html.

"Bingaman/Specter Climate Change Bill." Sen. Bingaman, Jeff. July 11, 2007. http://energy.senate.gov/public/_files/END07842_xml1.pdf.

"Civil Works Construction Cost Index; March 30, 2007 Revision." US Army Corps of Engineers. March 30, 2007. http://www.usace.army.mil/publications/eng-manuals/em1110-2-1304/entire.pdf.

"Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative." Maryland Department of the Environment. January, 2007.

"The EIA Petroleum Navigator." Energy Information Administration. http://tonto.eia.doe.gov/dnav/pet/pet_sum_top.asp

"EPA Analysis of The Climate Stewardship and Innovation Act of 2007: S.280 in 110th Congress." U.S. Environmental Protection Agency. July 16, 2007. http://epa.gov/climatechange/downloads/s280fullbrief.pdf.

"Final Scenario Analysis Modeling Assumptions." ISO-New England. May 16, 2007. http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/may212007/final_sa_modeling_assumptions.pdf.

"Fossil Energy Cost and Performance Baseline Studies: Volume 1; August Revision." National Energy Technology Laboratory. August, 2007. http://www.netl.doe.gov/energy-analyses/baseline_studies.html.

"The Future of Coal: An Interdisciplinary MIT Study." Massachusetts Institute of Technology. 2007. http://web.mit.edu/coal/.

"The Future of Nuclear: An Interdisciplinary MIT Study." Massachusetts Institute of Technology. 2003. http://web.mit.edu/nuclearpower/.

"Gas Daily." Platts. http://www.platts.com/Natural%20Gas/Newsletters%20&%20Reports/Gas%20Daily/.

"Gross Domestic Product: Implicit Price Deflator." U.S. Department of Commerce: Bureau of Economic Analysis. October 10, 2007. http://research.stlouisfed.org/fred2/series/GDPDEF/.

"The Handy-Whitman Bulletin, No. 165." Whitman, Requardt & Associates, LLP.

"New England Electricity Scenario Analysis." ISO-New England. August 2, 2007. http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf

"Nymex Futures Prices." http://www.nymex.com/media/092707.pdf.

"Testimony in FERC Docket No. ER03-563-030." Ex. ISO-8. Reed, John. August 31, 2004.

APPENDIX D: DEMAND-SIDE MANAGEMENT RESOURCE SOLUTION

I. INTRODUCTION

This Appendix describes the demand-side management (DSM)-focused resource solution for Connecticut, based on an evaluation of DSM conducted by *The Brattle Group* with substantial involvement by the Companies. This resource solution builds on work that the Companies have been carrying out over the past several years in collaboration with the Department of Public Utilities Control (DPUC), the Energy Conservation Management Board (ECMB) and other stakeholders. This resource solution envisions a significant increase in spending on DSM programs, with the objective of eliminating substantially all load growth over the next decade.

These goals incorporate the ECMB's Vision Statement to assist Connecticut's businesses to embrace energy efficiency and load management as an integral part of their business operation. The assessment contained in this section builds on work contained in prior documents:

- *Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwestern Connecticut Region*, Final Report for the Connecticut ECMB, GDS Associates, Inc. and Quantum Consulting, June 2004
- *New England Electricity Scenario Analysis*, ISO New England Inc., August 2, 2007
- *Conservation and Load Management Portfolio Plan*, Docket 06-10-02, Scenario 2 (Zero load growth) Supplemental Filing with the DPUC, The Companies, January 31, 2007

II. CONSERVATION AND ENERGY EFFICIENCY POTENTIAL

The energy efficiency potential study issued in 2004 identified the maximum achievable cost-effective potential for energy conservation and peak demand reduction associated with some 300 energy efficiency measures. The study built on research findings from over 200 other studies. It did not evaluate the potential for demand response measures. It found that 13% of energy consumption (4,466 GWh) and 13% of peak demand (908 MW) could be cost-effectively saved in Connecticut through commercially-available energy efficiency measures over a ten year period from 2003 through 2012. The estimate assumes that all measures that pass the Total Resource Cost (TRC) test are implemented for the maximum number of customers that can be

recruited through a concerted and sustained campaign involving highly aggressive program designs and delivery channels. Based on the study, if these savings were achieved, they would eliminate load growth in Connecticut out to 2012.

Although this study is a few years old, and there have been changes in the underlying assumptions for costs and savings, it is the most current estimate of the available potential in Connecticut. The ECMB, as required by statute, is in the process of initiating a more current effort that can be used to update future IRP efforts.

We estimate that approximately one-third of the savings from the 2004 Potential study has already been captured through changes in codes and standards and/or conservation efforts since its completion, leaving about 600 MW still available. At the same time, energy prices and avoided costs have increased substantially since 2004, which should raise the cost-effectiveness of other measures that otherwise were not found cost-effective in the 2004 study. Considering both of these effects, we expect that the increase in avoided costs since 2004 should more than offset the already-realized energy savings identified in the 2004 Potential Study. The Companies' ten year estimate of energy efficiency potential is 952 MW, which is approximately 5% higher than the 908 MW from the 2004 study and approximately 50% higher than the estimated remaining potential from the 2004 study.

We compared this estimate of achievable conservation to potential studies that have recently been completed in other areas of the country, including Vermont, Michigan, and California. Based on a review of those studies, the 952 MW estimate of maximum achievable energy efficiency potential appears reasonable. However, there remains some degree of uncertainty surrounding this estimate. The ECMB will be updating the 2004 Potential Study in 2008. Results from this effort may determine that DSM potential is even greater than currently anticipated. The Companies will utilize this updated study to refine and revise the estimates of maximum achievable cost effective savings.

III. New England Electricity Scenario Analysis

ISO New England undertook an eight-month long assessment of the future energy needs of the New England region. The assessment was carried out through an open process involving one hundred stakeholders. It yielded seven scenarios of the economic, reliability and environmental impacts of various demand-side and supply-side technologies on the New England power system that serves the needs of its 14 million inhabitants.

One of these scenarios involved an intense focus on energy efficiency and demand response measures. Called Scenario 2, its portfolio of demand-side resources was divided evenly between energy efficiency and demand response measures. In the aggregate, the scenario incorporated a significant investment in demand-side resources of some 5,400 MW in New England.

Results from this scenario and the study of potential savings have been used to develop estimates of the potential size of the DSM resource in Connecticut.

IV. Conservation & Load Management Scenario II Plan

The Companies developed a high level multi-year plan for achieving zero peak demand growth in the state by 2010, equivalent to a 140 MW reduction in peak demand. The plan assumed that funding constraints on several core DSM programs would be removed and those programs would be ramped up to substantially higher funding levels. The plan cited a recommendation made to the state's General Assembly by the Connecticut Academy of Science and Engineering which said, in part, "The state should adopt the principle that energy resource needs will first be met through all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible" – the precise language adopted in PA 07-242 Section 51(c).

The plan intended to achieve its aggressive goals by "aiming higher/going deeper," i.e., striving for the highest efficiency levels that are cost-effective. In addition, it sought to accelerate the replacement of older inefficient systems before the end of their useful lives. Another feature was integrated program design and delivery, i.e., integration of electric and gas programs and the initiation of one-stop shopping for all DSM programs. Finally, the plan involved integration

with other state-wide initiatives, such as the Climate Change Action Plan and the Governor's Energy Vision.

V. PROGRAM OPERATION

The current portfolio of programs offered by the Companies under the direction of the ECMB provides a solid foundation on which to build upon for the future. Despite this existing structure, a ramp-up period will be required to achieve a higher level of program operation. This ramp-up period would allow the expansion of vendor staff that is currently available and an increase in the number of vendors available to the program administrators. The DSM Focus resource solution envisions a ramp-up period of approximately 3 years before the programs could move to the next level of saving. It is expected that the programs will peak around 2014 and decline steadily out to 2018. The decline in program activity is due to anticipated changes in codes and standards as well as market transformation. For instance, if incandescent bulb conversions to Compact Fluorescent Lamps (CFLS) were no longer considered as an energy efficiency measure due to a code change, the potential DSM savings from residential programs would be significantly reduced (although energy savings would still result). Similarly, as an energy efficiency program matures, the high efficient equipment tends to become the baseline due to market transformation.

a. Residential DSM Programs

The key residential DSM programs designed to meet the aggressive goals are summarized below. Some of the offerings are based on the development of certain technologies within the next few years. For instance, light-emitting diode (LED) technology has developed rapidly in recent years to the point where it is an emerging (yet relatively expensive) option for residential usage. There is little doubt that LED is the lighting form of the future. However, its current use in the residential setting is still very limited and significant further development is necessary before it will go "mainstream" and become a significant program offering.

This LED example illustrates the technical challenges encountered when constructing a 10-year program expansion resource solution. Given the uncertainty of future technologies and of the regulatory and political framework that the Companies work in, the following program

descriptions should not be considered absolute, but rather, reasonable projections of an uncertain future based on the Companies experience and knowledge of DSM Program design. The following program summaries are high level descriptions of the Companies' "core" programs, i.e. programs that result in direct energy savings. Educational programs and offerings are not included below. By design, the Program descriptions do not provide the same level of detail that is found in the Companies annual C&LM Plan. The Companies fully anticipate that these programs will be refined and enhanced on an annual basis over the course of the next ten years as new technologies and markets are developed. These updates and additional detail will be provided in future annual C&LM plans.

Retail Products – This program mainly comprises of efficient lighting equipment, including LED technology, and high efficiency appliances. It is anticipated that compact fluorescent lamps (CFLs), which provide the bulk of current program savings, will become the norm a few years out in the future, due to changes in legislation and codes/standards changes and due to market transformation. It is expected that new technologies and initiatives will evolve such that they will mitigate to some degree the sizeable loss in savings that will accrue when CFL savings are no longer applicable. In addition, other initiatives such as energy efficient electronics will be considered for this program as those technologies become available.

Home Energy Solutions (HES) – This program has three components: 1) An in-home services program; 2) an HVAC component consisting of installation of high efficiency HVAC equipment and HVAC quality installation including ground source heat pumps; and 3) installation of high efficiency heat pumps (based on a pilot program) for customers with electric heat. Among the offerings of the In-Home HES program are comprehensive auditing of air sealing, duct sealing and direct installation of measures, early retirement of older appliances, customized energy conservation strategies for customers (including time-of-use rates), renewable options and loan and financing options. The three natural gas companies in Connecticut provide for the gas measures associated with the program. The HVAC component consists of rebates for high efficiency central air conditioning (and heat pump) systems for systems that pass performance testing. In addition, there are ground source heat pump incentives that are based on actual tested performance of the units. Finally, the Companies are currently conducting a pilot program

through HES to test the feasibility of using high efficiency ductless heat pumps to help residential customers who have electric resistance heat. The results of this pilot program (which are expected in 2008) will likely lead to some type of high-efficiency heat pump offering.

New Homes – The goal of this program is to minimize peak load growth associated with new residential construction. Currently, Program offerings include incentives for the installation of high performance insulation, high efficiency equipment, energy efficient lighting, and successful performance testing of homes *e.g.*, blower door testing and duct blasting. The Program offers Energy Star certification for qualifying homes and leverages the federal tax credits that are currently available. Since residential cooling is a significant driver behind peak load growth, the Companies will work on minimizing the impact of cooling on peak demand within the New Homes Program. Going forward, the Program will move towards Green Building and Zero "Peak" Energy options. By collaborating with the Connecticut Clean Energy Fund, the Program offerings may include installations of photovoltaic systems, as well as solar thermal water heater options. In conjunction with this program, the Companies will work with local building officials to help increase awareness of energy issues in residential construction and to assist building officials with the enforcement of energy related building codes.

Water Heating – This program will target all cost effective water heating solutions to residential customers with high hot water loads and is not expected to start until 2013. It is at this point that the Companies are estimating that the next generation of viable electric (i.e. heat pump) water heating technologies will be fully developed and commercially available.

Low Income Program – Both UI and CL&P offer a Low Income Program to their customers that are at or below 60% of state median income level. Both the UI Program ("UI Helps") and the CL&P Program ("WRAP") are in-home services programs that offer full weatherization, replacement of less efficient appliances, installation of water saving measures, and energy efficient lighting upgrades. Both UI and CL&P have agreements with most of the local Community Action Agencies in their territories and utilize those relationships to identify clients and to "piggy-back" available services and offerings to customers.

Direct Load Control Program – The Direct Load Control Program will target homes (and small businesses) with central air conditioning systems. The goal of the program will be to reduce summer peak loads by remotely cycling the compressors in central air conditioning systems. In addition, the application of direct load control technology to other end-uses such as water heating and pool pumps will be investigated. This program may be offered in conjunction with the Home Energy Solutions Program and the New Homes Program to offer customer a complete package of energy savings and peak reducing measures. In addition, program design will compliment the future deployment of advanced metering infrastructure (AMI) meters and time-of-use rates.

The following tables illustrate the ramp-up of Residential DSM programs from 2009 through 2018.

Table D.1: Residential DSM Programs: 3, 5, and 10-Year Plans

Program Strategy	3 Year Plan – 2011	5 Year Plan > 2013	10 Year Plan > 2018
Retail Products	• 2008 transition year • Fully in effect by 2009 • Maximize CFL's • Increase appliance portfolio	• Achieve near complete saturation of CFL's • Developing new technology including high efficiency appliances, LED lighting and electronics.	• CFL's no longer available or drastically reduced. • New high efficient appliances and LED lighting main focus of program.
Home Energy Solutions	• 2009 – first year of ramp-up. Begin the development of infrastructure of home performance technicians	• Significant participation • New technology implemented • Migration towards a market based program,	• CFL's no longer available or drastically reduced. • New high efficient appliances and equipment, home performance, and lighting main focus of program
New Homes	• 2009 – first year of ramp-up • Coordinate with CT Clean Energy Fund to offer renewable options.	• New technology implemented • Code Support • Core focus of green building, zero "peak" energy, and renewable features	• High penetration of Zero "Peak" Energy, Green homes.
Water Heating	• 2009 – first year of ramp-up	• New technology implemented	• New technology fully developed and market transformed
Low Income	• 2009 – first year of ramp-up	• Significant Participation • Higher efficient equipment being utilized	• High saturation
Direct Load Control	• 2008 transition year • Fully in effect by 2009	• Increased Participation and integration with AMI Meter deployment and TOU rates	• Significant participation and load reduction • Fully integrated with TOU rates

b. Commercial and Industrial DSM Programs

The key commercial and industrial DSM programs designed to meet the goals of this report are summarized below. As is the case with the Residential Programs, the C&I Program descriptions were challenging in nature because of the long time frame involved and the large uncertainties regarding the development of technologies and markets, the ability to ramp up programs, and the long planning horizon.

High Performance Core Connecticut Energy Efficiency Fund (CEEF) Programs – Within this category are the Energy Conscious Blueprint, Energy Opportunities and Small Business Energy Advantage programs which have been expanded from current efforts.

Energy Conscious Blueprint - The Energy Conscious Blueprint program is a lost opportunity program which assists building/facilities to achieve 30-50% energy savings beyond the Connecticut's building code. This program also integrates with other initiatives such as commercial lighting, green schools, etc. Outreach, training and educational efforts to achieve these goals also form a core part of the program.

Energy Opportunities - The goal of the Energy Opportunities program is to promote high performance equipment, designs, systems and process retrofits that result in energy efficiency of entire buildings. Incentives will also be provided to replace older, inefficient equipment such as chillers, old HVAC units etc. with high performing solutions.

Small Business Energy Advantage - The Small Business Energy Advantage program is designed for smaller facilities (under 200 kW) with the main goal of moving from narrow incremental retrofit efforts to comprehensive projects and measure bundles that include demand response capabilities.

Integrated O&M Strategy – The goal of this program is to integrate operational, maintenance and commissioning opportunities for buildings/facilities to integrate energy efficiency solutions

into daily operations. Educational outreach and certification programs are also envisioned to be an integral part of this program effort.

Code Support and Code Commissioning – The goal of this program is to provide support for codes and standards compliance and an expanded effort to commission current and future codes and standards through CEEF C&I programs.

Energy Efficiency Infrastructure Development and Market Transformation Initiatives - In order to meet the aggressive demand side management goals set for Connecticut, support through educational efforts, training and professional development have to be an integral part of the portfolio. This is achieved through partnerships with educational institutions, trade and business associations and other market allies. These market transformation initiatives will strengthen strategic alliance with other utilities, government agencies and other key players to achieve broad market changes.

Business Energy Services – The goal of this program is to provide a holistic one-stop energy solution to businesses through integration of energy efficiency, load management, load response, direct load control, distributed generation, renewable energy systems, CHP and other initiatives to facilitate an effective use of CEEF and other C&I programs.

Business Energy Challenge – This program calls for businesses to make commitments to aggressive energy efficiency and load reduction goals by participating in a strategic planning effort that includes an executive-level assessment of business energy management practices, energy efficient capital improvement plan, and a commitment of adequate staffing and other resources. Participants in this program will be expected to implement all or most of the recommended measures that are cost effective from a life cycle costing perspective. In exchange for accepting this energy challenge businesses will receive a custom tailored package of the entire CEEF conservation and load management offerings into one cost-effective bundle, technical consulting services, and other support to necessary to make the transition.

Under-Utilized/Emerging Technologies, Designs and Practices – Efforts will be made to incorporate under-utilized and emerging technologies (such as daylighting design, ductless mini-split heat pumps, etc.) into C&I programs as deemed fit.

Load Response Program –This program is designed to promote customer enrollment in one of several ISO-NE-operated load response programs. CL&P and UI provide enrolling customers with the ISO-NE-required internet-based communications system. CL&P and UI also provide enrolling customers with a one-time set-up incentive to cover costs for data, phone, or metering connections. The program mandates load curtailments from customers who enroll and provides enhanced system reliability during peak system load conditions. The Price Response program helps to mitigate high Locational Marginal Prices throughout the year. Utilizing a current Department of Environmental Protection ("DEP") Permit, customers may run emergency generators to reduce load on the grid under emergency conditions. CL&P and UI provide direction on operating emergency generators in compliance with Connecticut air quality requirements during Demand Response events.

The following table illustrates the ramp-up of C&I DSM programs from 2009 through 2018.

Table D.2: Commercial & Industrial DSM Programs: 3, 5, and 10-Year Plans

Program Strategy	3 Year Plan – 2011	5 Year Plan > 2013	10 Year Plan > 2018
High Performance Core Programs (ECB, EO, SBEA)	• 2008 transition year • Fully in effect by 2009 • ECB = improved code compliance	• Continuously improving strategy • ECB supports next code upgrade	• Continuously improving strategy
Integrated O&M strategy	• 2008 development year • 2009 – first year of ramp-up • Pilot in 2009 w/ 10 businesses	• 3 year ramp-up, fully integrated into core programs	• Continuously improving • Market transformation
Code Support and "Commissioning"	• 2008-9 continue training and education • Participate in regional/national initiatives • Partial compliance	• Continued participation in regional/national codes and standards initiatives • Significantly Improve compliance	• Update strategy for the next generation of codes and standards • Near total compliance
Business Energy Services	• 2008 development year • 2009 – first year of ramp-up • Integration w/ load management • Partial participation rate	• 2 year ramp-up, fully integrated into core programs • Integration w/ load management • Partial participation rate	• Continuously improving strategy • Major driver of integrated energy efficiency and load management • Integration w/ load management • Significant participation rate
Business Energy Challenge	• 2008 – pilot project • 2009 – first year of ramp-up • 2009 = 4-6 companies	• 3 year ramp-up • Apply also to small-medium sized businesses • By 2011 – Several companies	• Major driver of market transformation • Significant company participation
Under-utilized & emerging technologies, practices and designs	• 2008 transition year, tech assessment • Update measure lists by 2009 • Savings factored into core programs	• Continuously incorporating new technologies/etc. • Savings factored into core programs	• Major driver of market transformation • Savings factored into core programs

c. Projected Savings in Energy Consumption and Peak Demand

The Companies provided *The Brattle Group* with the most recent (October 2007) data on their DSM plans. Based on review and discussion, two DSM cases were developed, a Reference Case (which is the basis for DSM assumptions in the other resource solutions) and the DSM – Focus resource solution, which includes the program expansions. The following are net estimates of direct program savings and do not include the long term market impacts that may be associated with programs; changes in codes and standards that may be influenced by programs; or naturally occurring conservation that would have occurred in absence of the programs.

- Reference Case: This includes all DSM programs, both EE and DR, that were relatively certain of approval and funding
- DSM Focus Resource Solution: This extends the Reference Case DSM programs in several directions, assuming that the state's policy makers would find it in the public interest to pursue additional cost-effective DSM. It was also assumed that the DPUC would order and specify funding sources for this expanded effort.

The Companies provided end-of-year estimates of savings from their energy efficiency and demand response programs and the corresponding budgets for those programs and indicated that one-third of savings were realized in the current year and two-thirds savings were realized in the following year. In other words, one-thirds of the savings are from that year's programs and two-thirds from the previous the year's programs. The following tables and figures summarize the demand and energy savings and budgets that correspond with the DSM programs discussed above.

Table D.3: Reference Level DSM MW Savings

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	10	13	23	35	48	61	74	86	98	110	123	137
UI DR	18	39	82	83	84	84	85	86	87	87	88	89
CL&P EE	36	47	83	124	165	206	246	281	308	335	362	390
CL&P DR	326	358	420	411	411	411	411	411	411	411	411	411
Total (UI + CL&P)	389	457	608	653	707	762	816	863	904	944	985	1,026

Figure D.1: Reference Level DSM MW Savings

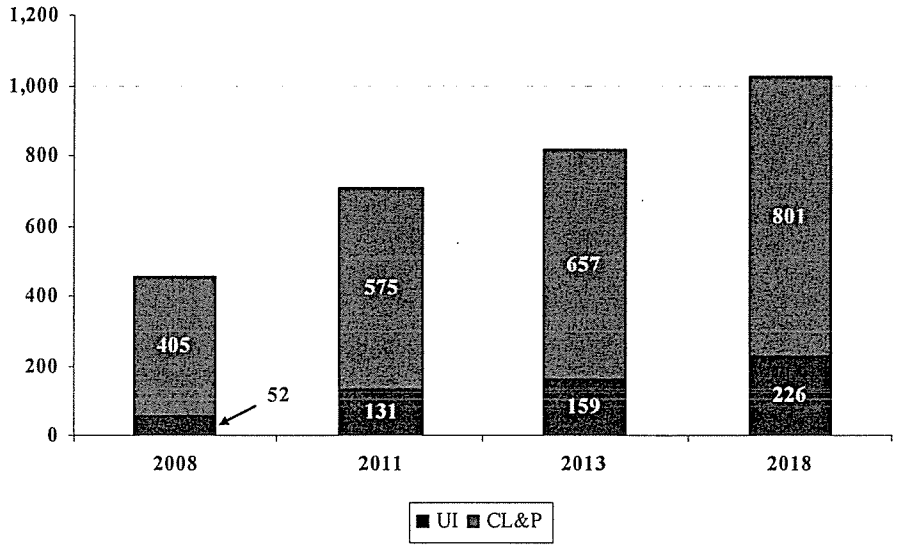
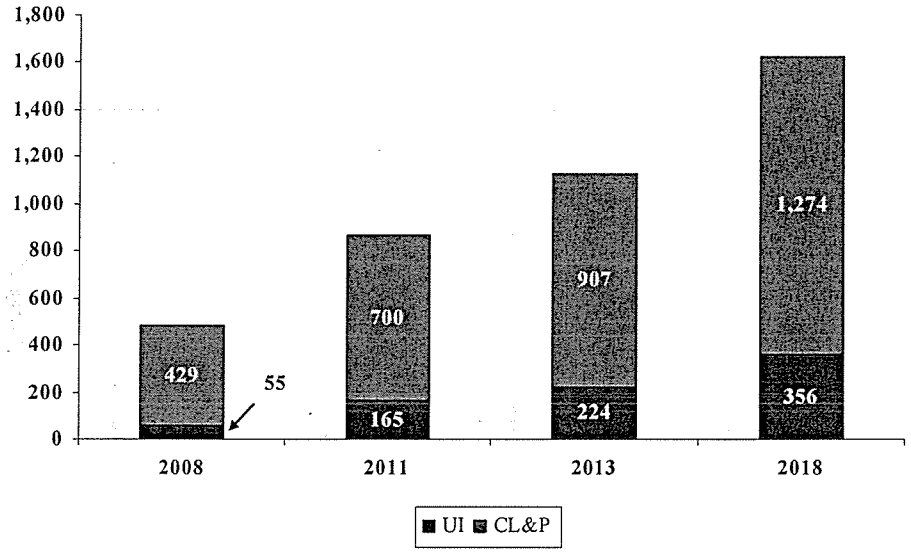


Table D.4: DSM-Focus Level DSM MW Savings

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	10	13	24	38	57	81	107	131	157	182	208	234
UI DR	20	42	92	103	108	113	118	118	119	120	121	122
CL&P EE	36	50	96	154	224	308	401	501	594	668	723	768
CL&P DR	346	380	447	453	476	496	506	506	506	506	506	506
Total (UI + CL&P)	410	484	658	748	865	998	1,131	1,257	1,376	1,476	1,558	1,630

Figure D.2: DSM-Focus Level DSM MW Savings



In 2008, demand savings from the Base DSM programs constitutes about 6.1% reduction of system peak (most of this through DR) whereas the DSM Focus resource solution constitutes about 6.5% reduction of system peak. By 2018, demand savings from the Base DSM scenario constitutes about 12% reduction of system peak whereas DSM Focus resource solution constitutes about 19.1% reduction of system peak.[1] DSM efforts in the Base scenario lead to about 93% offset of load growth between 2008 and 2018. The next two tables show the energy savings from the DSM efforts.

[1] Beyond 2018 savings from EE and DR programs were assumed to grow at the same rate as Connecticut system peak.

Table D.6: Reference Level DSM GWh Savings

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	54	72	131	198	269	343	412	467	524	582	642	704
UI DR	0	0	0	0	0	0	0	0	0	0	0	0
CL&P EE	194	256	455	678	898	1,123	1,343	1,531	1,680	1,824	1,969	2,117
CL&P DR	0	0	0	0	0	0	0	0	0	0	0	0
Total (UI + CL&P)	248	329	586	876	1,167	1,466	1,754	1,998	2,204	2,406	2,612	2,821

Figure D.3: Reference Level DSM GWh Savings

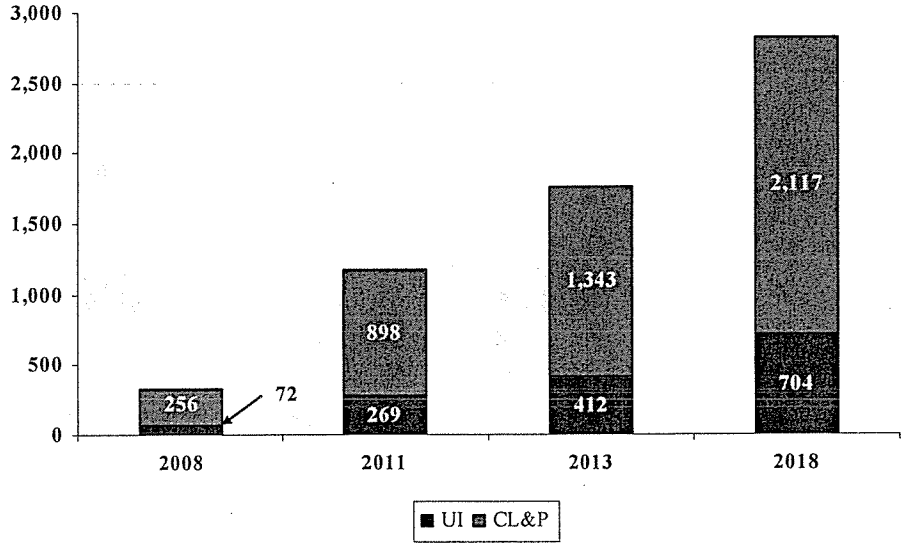
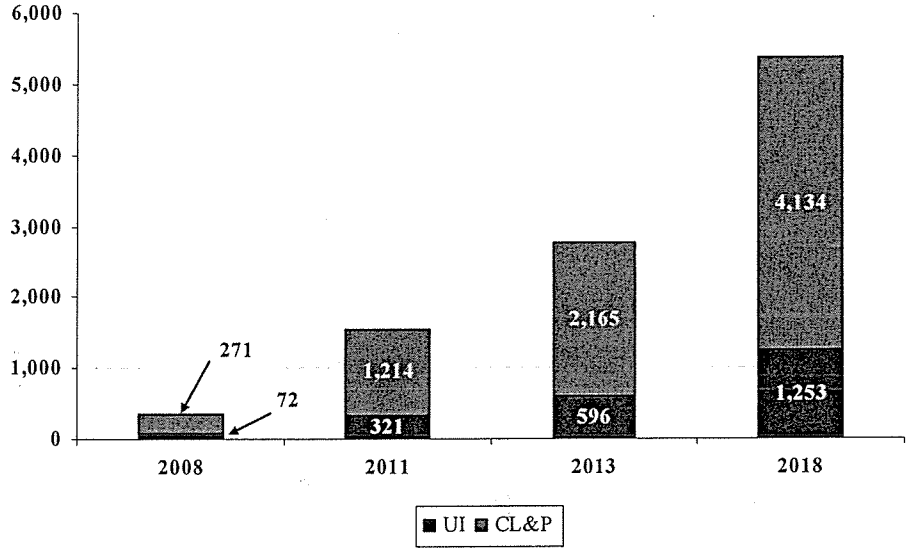


Table D.7: DSM-Focus Level DSM GWh Savings

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI Total	54	72	133	214	321	455	596	724	854	985	1,118	1,253
CL&P Total	194	271	521	832	1,214	1,663	2,165	2,702	3,203	3,597	3,892	4,134
Total (UI + CL&P)	248	344	654	1,046	1,536	2,117	2,761	3,426	4,057	4,582	5,010	5,387

Figure D.4: DSM-Focus Level DSM GWh Savings



The budgets corresponding to the above DSM programs are shown in the following tables.

Table D.8: Reference Level DSM Annual Budgets (Nominal $ Million)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	$17	$17	$19	$21	$23	$24	$25	$25	$26	$27	$28	$29
UI DR	$1	$2	$4	$4	$4	$4	$5	$5	$5	$5	$5	$5
CL&P EE	$68	$68	$71	$78	$81	$82	$83	$85	$86	$87	$88	$89
CL&P DR	$25	$24	$23	$23	$23	$23	$23	$23	$23	$23	$23	$23
Total (UI + CL&P)	$111	$112	$118	$128	$131	$134	$136	$138	$140	$142	$144	$146

Figure D.5: Reference Level DSM Annual Budgets (Nominal $ Million)

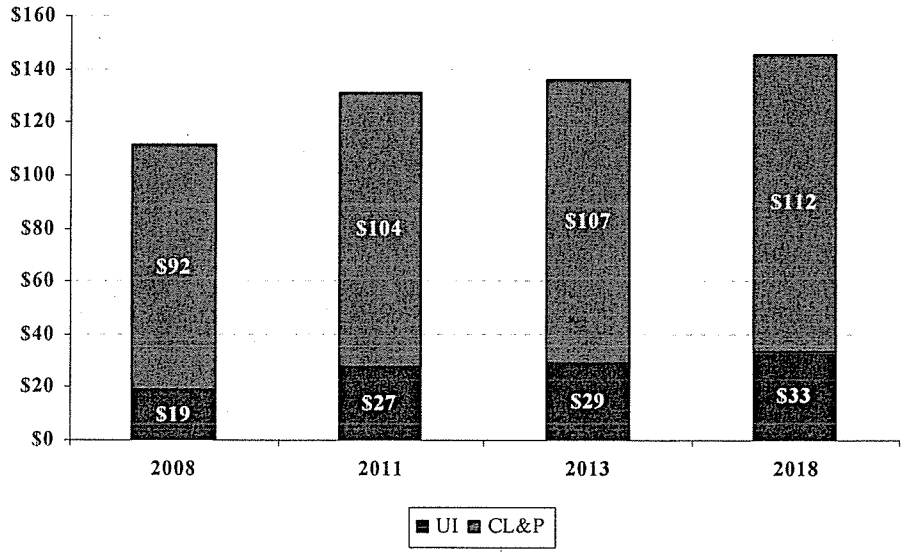
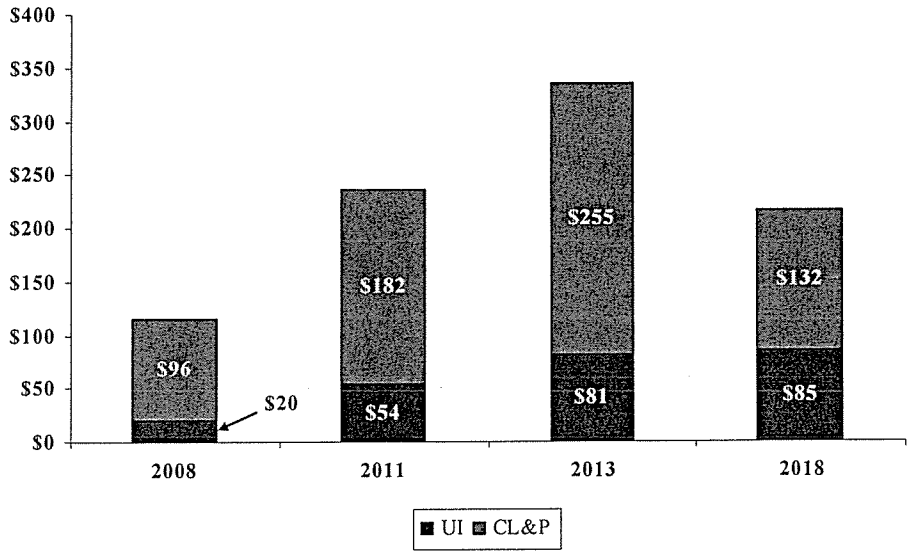


Table D.9: DSM-Focus Level DSM Annual Budgets (Nominal $ Million)

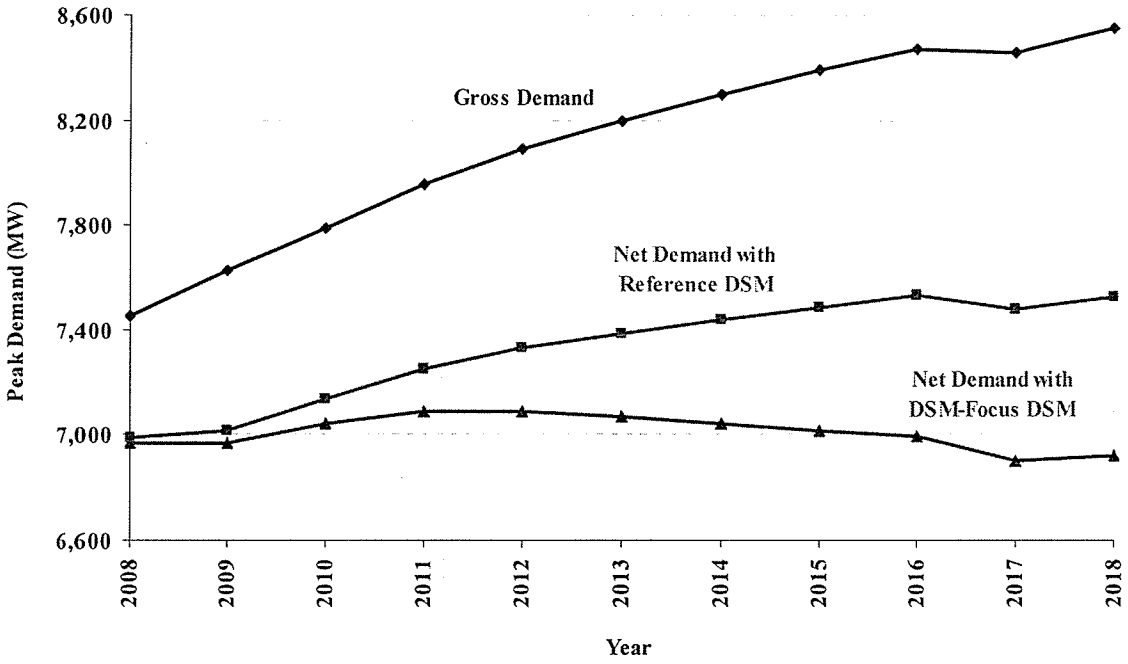
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI Total	$18	$20	$26	$38	$54	$70	$81	$81	$82	$83	$84	$85
CL&P Total	$94	$96	$109	$140	$182	$226	$255	$270	$256	$206	$153	$132
Total (UI + CL&P)	$112	$116	$135	$177	$236	$296	$336	$352	$338	$289	$236	$216

Figure D.6: DSM-Focus Level DSM Annual Budgets (Nominal $ Million)



The next figure shows Connecticut peak demand under different scenarios.

Figure D.7: CT Peak Demand (MW) Forecast under Different DSM Scenarios



Source: 2007-2016 CT Peak Demand (MW) data from ISO-NE spreadsheet titled "isone_2007_forecast_data.xls." 2017-2018 CT Peak Demand (MW) data based on *The Brattle Group* extrapolation of hourly ISO-NE data. DSM data for the Reference and DSM-Focus cases provided by CL&P and UI.

VI. FUTURE DEVELOPMENTS

It is anticipated that a new study on the potential savings from new DSM programs will be carried out next year to update the estimate of potential DSM savings that was carried out in the 2004 report. The new study will be helpful in refining the Companies' 10 year DSM estimates and may help identify new technological developments and innovations in program and marketing. In addition, it may identify opportunities associated with demand response programs that were not covered in the previous effort. New technology developments have been anticipated, but evolving technologies may create new opportunities for savings. Advances in communication and metering technology may make program offerings possible that could not

previously be envisioned. Finally, the new study may assess the likely impact of dynamic pricing programs which are not included in the current plan.

Another factor to keep in mind is that increasing amounts of savings will likely be achieved at increasing unit cost. There is ample evidence from the vast literature on DSM programs that the "supply curve" of savings is subject to the law of diminishing returns and exhibits an upward slope. Studies carried out in large states such as California and Florida suggest that budgets have to be raised substantially if the DSM strategy calls for achieving all cost effective potential. In reference cases, many analysts assume that utilities will have to provide incentives to customers in order to buy down the payback period to two years. This usually yields market penetration rates in the 15 to 25% range. In order to achieve the maximum achievable potential, which may range from 50 to 65% of the economic potential, the utility or other agency administering the DSM program has to cover one hundred percent of the customer's incremental cost. Even then, many customers would still not bother to sign up. The only way to achieve the entire economic potential is through more stringent codes and standards.

However, more stringent codes and standards will reduce the potential savings that can be achieved through utility DSM programs. In California, about half of the efficiency gain during the past three decades has come from the state's Title 20 and 24 standards for appliances and buildings respectively. As one looks at the future, the same is likely to be true. In addition, due to new legislation and changes in codes and standards in several states (and other nations such as Australia and the United Kingdom), no incandescent bulbs will be sold. This would eliminate savings from any utility programs that are directed at replacing incandescent bulbs with CFLs. While LEDs can be brought into the picture, to take the place of CFLs, on an absolute basis, the savings per bulb change out will be a lot lower.

VII. Some Key Considerations of the DSM Solution Include:

- **Continued Funding of Reference Case DSM**

  Continued and consistent funding of DSM is crucial to Connecticut's ability to achieve the levels of capacity savings estimated in this IRP. An interruption or curtailment in funding can have negative impacts on the infrastructure

(contractors, vendors, engineers, etc) needed to support the design, implementation and administration of DSM activities as well as have a negative impact on customer acceptance of DSM programs and initiatives.

- **This IRP is not a C&LM planning document**
  This document is not a C&LM planning document nor does it replace the rigor involved with planning and evaluating cost-effective measures and programs. Instead, the IRP document utilizes the approved programs and measures created during this planning process to develop the potential capacity resulting from Reference Case and increased levels of DSM activity.

- **The IRP is not a DSM potential study**
  The IRP utilizes the potential for DSM from the most recent achievable potential study and overlays the programs and measures that were developed during the C&LM planning process to obtain the quantity of DSM capacity estimated in this report. The achievable potential study is a study that is required to be updated by the ECMB in PA 07-242. The capacity estimate in future IRPs from DSM will be updated based upon new information from the updated potential study.

- **DSM ramp up is unprecedented**
  The IRP estimates a tripling of DSM activity in five years. The amount of achievable DSM is expected to be constrained by the physical resources necessary to design, install, and administer programs and initiatives. An increase in DSM activity will require changes in program design, additional engineer time for design of energy efficiency projects, additional contractor labor to construct and install projects, vendor support to supply the necessary energy efficient equipment, as well as skilled resources to administer and evaluate project installation and program performance.

APPENDIX E: RENEWABLE ENERGY

Renewable electric generation is a key aspect of utility resource planning in New England. Connecticut and other New England states have been in the forefront of a movement to require a certain percentage of renewable energy in the generation supply mix. However, the rapidly increasing renewable energy requirements in New England may exceed the near-term potential of renewable energy developers to produce the required amounts in the coming years. This has some important implications for resource costs and customer rates. Because of the importance of state, regional and federal policies in encouraging renewable energy development, this appendix begins with policy issues, then concludes with a discussion of availability and cost of renewable energy in Connecticut.

I. CONNECTICUT RENEWABLE PORTFOLIO STANDARD

Connecticut, like other New England states, has a renewable resource requirement that applies to load-serving entities. Under the Connecticut Renewable Portfolio Standard (RPS), a certain percentage of electricity sold at the retail level must come from renewable or otherwise eligible resources. The Connecticut RPS segments eligible resources into three classes:

- **Class I:** Wind, Solar Thermal, Photovoltaic, Wave, Tidal, Ocean Thermal, Landfill Gas, Low-emission Sustainable Biomass, Fuel Cells and certain Small (<5 MW) Hydroelectric
- **Class II:** Other Biomass, Small Hydroelectric, Municipal Solid Waste (MSW)
- **Class III:** Energy Efficiency Measures (instituted after January 1, 2006) and Combined Heat and Power (CHP)

The required percentage of retail load that must be served by each resource class escalates as follows:

Table E.1: Percentage Requirements under the Connecticut Renewable Portfolio Standard

Year	Class I	Class II	Class III
2007	3.5%	3.0%	1.0%
2008	5.0%	3.0%	2.0%
2009	6.0%	3.0%	3.0%
2010	7.0%	3.0%	4.0%
2011	8.0%	3.0%	4.0%
2012	9.0%	3.0%	4.0%
2013	10.0%	3.0%	4.0%
2014	11.0%	3.0%	4.0%
2015	12.5%	3.0%	4.0%
2016	14.0%	3.0%	4.0%
2017	15.5%	3.0%	4.0%
2018	17.0%	3.0%	4.0%
2019	19.5%	3.0%	4.0%
2020	20.0%	3.0%	4.0%

There are three basic ways that utilities can comply with the RPS requirement:

- A utility can purchase generation from eligible sources in Connecticut or in ISO-NE for physical delivery to Connecticut customers, bundled with the Renewable Energy Certificates (RECs) that the source generates (bundled compliance).
- A utility can purchase RECs from generators that can physically deliver eligible renewable electric power into ISO-NE, but who sell the renewable attribute separately from the energy produced (REC compliance).
- Utilities can "buy-through" the RPS compliance obligation by making a payment to the State (sometimes called an Alternative Compliance Payment or ACP) that is set at a constant $55/MWh. The funds are deposited in the Renewable Energy Investment Fund and used by the Connecticut Clean Energy Fund to promote Class I renewable energy projects in Connecticut.

II. PROJECT 100

In order to stimulate the development of Class I renewable resources (especially fuel cells manufactured in Connecticut), the Legislature has required that the Companies enter into long-term contracts with renewable developers for a total of 150 MW of Class I generating capacity. This initiative was initially called "Project 100" as it required 100 MW of Class I resources under contract by 2008. PA 07-242 expanded this requirement to 150 MW under contract by

2010. The DPUC approved a 15 MW biomass facility in the Project 100 Round 1 solicitation in 2006. The facility was originally due to begin operations on December 31, 2007; however, the operation date has been pushed back to May 2010 by the project developer. On December 21, 2007, the DPUC announced a Draft Decision in the Round 2 solicitation, conditionally approving 7 projects totaling about 109 MW (giving a total approved capacity of about 124 MW) and ordered the commencement of a Round 3 solicitation to obtain the remainder of the 150 MW requirement.[1]

Under these contracts, the Companies would retain the Class I RECs associated with the eligible generation, except in the case of fuel cells where the developer can keep 50% to 100% of the RECs. Thus, the contract prices will reflect the presumed avoided costs of acquiring RECs. However, none of the Round 2 approved projects are currently competitive even with REC prices at $25/MWh, although several biomass facilities may be roughly competitive if one assumes REC prices at $50/MWh, according to the analyses submitted to the DPUC. The three fuel cell projects approved (total of 16 MW), on the other hand, were not remotely competitive even with REC prices of $50/MWh.

The Round 2 solicitation suggests several observations regarding the prospects for renewable energy development in Connecticut. First of all, the lack of competitive projects with REC prices below $50/MWh – even with the prospects of guaranteed long-term contracts – means that the growing Connecticut RPS requirements will likely be met with (1) high REC prices for in-state renewable development; (2) significant volumes of RECs from elsewhere in New England (assuming they are available); (3) substantial reliance on alternative compliance payments, or a combination of all of these.[2] Second, recalling the project delay from the Round 1 project, some of the Round 2 projects may not be operational within the proposed timeframe, even with a long-term contract in place. Renewable project attrition is high – experience from other procurements suggests that 20% - 50% of projects are delayed or abandoned at some stage, for a variety of

[1] Docket No. 07-04-27 DPUC Review of Long-Term Renewable Contracts – Round 2 Results, December 21, 2007.

[2] CL&P paid over $3 million in alternative compliance payments in 2006, according to a filed report (DPUC Docket 07-09-14, October 15 (corrected) letter). The corresponding figure for UI remains confidential under their supplier agreement.

reasons. Even if all of the Round 2 projects were built by the end of 2009 (under their proposed schedules) they would supply roughly an additional 925 GWh of Class I renewables to satisfy the 2010 RPS requirement (assuming an 85% capacity factor for all projects). However, the Class I RPS requirement by 2010 is 7.0% of Connecticut electricity sales, or double the 3.5% requirement for 2007. The 2010 requirement for Class I renewables will likely approach 2,500 GWh, and so the combined output from the entire slate of Round 2 project (if operating) would not meet the incremental Class I requirement (above the 2007 level) of about 1,300 GWh. Therefore, unless additional Class I renewables emerge by 2010, the REC price for Class I renewables in Connecticut will remain high – at or near the $55/MWh alternative compliance payment level – and at least part of the requirement would be met by alternative compliance payments rather than renewable generation.

The Project 100 experience also suggests that there are limits to which long-term contracts can help reduce REC prices, at least in Connecticut. In general, long-term contracts with renewable developers can reduce the cost of acquiring RECs. A long-term contract for RECs at a specific price can hedge renewable developers against a potential drop in the REC spot price in the event that surplus renewable generation emerges. This hedge can enable renewable developers to obtain project financing.[3] When a renewable developer can profitably build and operate a project while receiving guaranteed REC payments, utilities can sometimes negotiate a long-run REC price that is well below the ACP. Although such an arrangement would represent a savings for utilities compared with paying higher spot REC prices or making alternative compliance payments, should REC prices actually drop below long-term contract prices, utilities would hold out-of-market REC contracts that could prove expensive for customers and risky for utilities.

III. RPS AND RENEWABLE DEVELOPMENT IN NEW ENGLAND

The Connecticut RPS (primarily Class I) is very similar to other RPS requirements in New England in terms of required percentages as well as the flexibility to obtain RECs throughout the New England market. Therefore, the New England States are usefully analyzed as a single RPS

[3] Developers still incur operational risks that REC production will not meet contract levels. If that happens, future net revenues fall from fewer REC sales and from covering contractual amounts with market purchases of RECs or liquidated damages.

compliance market. However, there are two aspects of the Connecticut RPS that will affect how the Companies might be able to comply with the requirement over the long run. First, as discussed later, Connecticut has significantly lower Class I renewable resource potential (especially wind) than other New England states, meaning that long-run compliance with the Connecticut RPS could depend substantially on RECs from elsewhere in New England. Second, the ACP is not indexed to inflation as it is in Maine, Massachusetts, New Hampshire and Rhode Island. In those states, the ACP levels were established at $50/MWh in 2003 and escalated at the Consumer Price Index (CPI); they reached $57.12/MWh in 2007.

Because of the likely dependence on RECs generated elsewhere in ISO-NE, the economic impact of RPS in Connecticut is heavily influenced by the growth of renewable electric generation in other New England states relative to the escalating RPS requirements across the region. Recent experience in New England suggest a potentially protracted period of high REC prices (close to ACP levels), as actual renewable development lags the rapidly escalating regional RPS requirements. Construction costs for renewable generation have increased significantly in the past several years and in some cases renewable resource development has encountered local resistance. As a consequence, renewable developers have commanded REC price premiums that are close to ACP in other New England states.

Although it is beyond the scope of this study to estimate the future renewable energy development in New England, the ISO-NE *2007 Regional System Plan* (RSP) examines the escalating regional RPS requirements through 2016 and compares them to the eligible resources in the ISO-NE Generator Interconnection Queue (a list of proposed projects that have requested an interconnection study from ISO-NE). This comparison revealed that if <u>all</u> of the projects in the Interconnection Queue were built, the additional renewable generation (8,866 GWh) would exceed the incremental requirements from RPS in New England between 2006 and 2012 (5,881 GWh) by a comfortable margin. In fact, the majority of these projects may never come to fruition. For example, about 63% of the new renewable generation in the Interconnection Queue comes from on-shore and off-shore wind projects, many of which have experienced significant resistance from local communities. According to ISO-NE:

> In the past, the region has experienced the withdrawal of a significant portion of projects in the queue before the projects were built. The project attrition has been due to project cost escalation, financing, siting, permitting problems, or a combination of these issues.[4]

If half of the eligible generation from the ISO-NE Interconnection Queue were available by 2012, then there would remain a significant shortfall in new renewable generation to satisfy growing RPS demands. This possibility does not reflect a stagnant outlook for renewable development in New England – renewable power is a vibrant industry that certainly will grow. However, the pace of renewable development relative to the ambitious, rapidly escalating regional RPS requirements will determine REC prices in the near and mid-term. There is growing concern in the region that currently high REC prices (near ACP levels) may persist for some time. While high REC prices will help stimulate renewable project interest from developers, other constraints on renewable development such as siting and permitting could retard the pace of development to keep REC prices very near ACP levels.

For this study's purpose, however, the most important aspect of the Connecticut RPS is the constant ACP price that is not adjusted for inflation over time. As inflation-adjusted ACP prices rise in other New England states, then Connecticut utilities may have very limited access to scarce RECs, since they will naturally flow toward those states where the ACP price is higher. Under these conditions, even renewable generators that might chose to locate in Connecticut might elect to sell RECs to utilities in other states with higher ACP levels. Thus, there is a very real prospect that Connecticut utilities will eventually comply with the Class I RPS primarily or nearly exclusively through the $55/MWh alternative compliance payments. While the $55/MWh price level in Connecticut will serve to limit the impact of higher regional REC prices for Connecticut retail customers, it also could eliminate access to RECs produced elsewhere in New England if regional REC prices exceed this level.

[4] *2007 Regional System Plan*, ISO-NE, p. 71. Projects often enter the Interconnection Queue in early stages of development; a position in the queue is more an expression of development interest than actual viability.

IV. DAYZER ANALYSIS ASSUMPTIONS

In this study, we assume no significant contribution of Class I resources to meet the Connecticut RPS from resources physically located in CT beyond the Project 100 capacity, where we assume the full 150 MW of development.[5] This is probably an overstatement, since even legislatively mandated contracts do not guarantee eventual project development. However, we assume that the price paid by the Companies for Class I RPS compliance through RECs, contract premiums with Project 100 developers, or through alternative compliance payments are all at the $55/MWh level in nominal terms, reflecting the market outlook described above. This translates into a cost burden on Connecticut customers of about $200 million in 2011, $230 million in 2013 and between $300 and $320 million in the 2018 Current Trends Scenario (in 2008 dollars).

Table E.2: Cost of Compliance with RPS Assuming $55/MWh Nominal REC or ACP

	2011	2013	2018
Current Trends Scenario			
Conventional	202	231	324
DSM-Focus	200	224	299
Nuclear	202	231	324
Coal	202	231	324
Strict Climate Scenario			
Conventional	199	227	315
DSM-Focus	197	220	291
Nuclear	199	227	315
Coal	199	227	315
High Fuel/Growth Scenario			
Conventional	199	229	326
DSM-Focus	197	225	311
Nuclear	199	229	326
Coal	199	229	326
Low Stress Scenario			
Conventional	215	250	366
DSM-Focus	213	243	342
Nuclear	215	250	366
Coal	215	250	366

[5] We do track the energy from refuse-fired facilities (Class II), and the demand-side management (DSM) programs included in all resource solutions are estimated to satisfy the Class III requirements.

V. Remote Renewables and Enabling Transmission

Explicitly analyzing renewable energy potential or projections of renewable energy development in New England is beyond the scope of this analysis. However, there is growing interest in the prospects for building substantial windpower capacity in northern New England (*e.g.*, Maine and New Brunswick) along with transmission that might enable energy delivery into the rest of ISO-NE in order to satisfy growing renewable energy demands. Because this resource strategy must be pursued on a regional basis, it is not one that the Companies can pursue as an independent procurement strategy. However, some of the illustrative tradeoffs can be shown with a simple model that estimates the value of windpower revenues (including RECs) in excess of construction and operating costs, and compares that net revenue to the potential costs of building transmission. This helps highlight some of the basic economic considerations that would be encountered in examining the prospects for combined windpower and transmission development in northern New England. The screening analysis assumes:

- A 1,000 MW wind project in northern New England
- An overnight cost of for wind capacity of $2000/kW, a real capital charge rate of 11.36%, and fixed O&M of $30.5/kW-year.
- Energy revenues are derived using DAYZER prices adjusted for seasonal and daily windpower capacity factors, under an assumed annual capacity factor of 32%.
- The value of renewable energy credits is assumed to be $55/MWh (in 2008 dollars), which is slightly below the ACP in other New England states of approximately $59/MWh.
- Federal production tax credits are assumed to remain at the current rate of $20/MWh (in real terms) for the first ten years of operation.
- Each MW of windpower would offset only 0.2 MW of other capacity, consistent with ISO-NE rules, and the capacity price value is derived from the Current Trends scenario with the Conventional resource solution.

Table E.3 shows the annual revenues and costs of windpower on a $/kW basis, and the annual surplus of revenues over costs. Assuming 1,000 MW of wind capacity, the annual surplus could support the annual capital requirements of $952 million worth of transmission construction. If transmission costs $3 million per mile, then the annual surplus of wind revenues over costs could support 317 miles of needed transmission.

Table E.3: Windpower Net Revenues and Transmission Costs

REVENUE (2008$/kW-year)	
Energy Revenue	183.2
Production Tax Credit	20.0
Renewable Energy Credits	153.5
Capacity Revenue	9.1
Total Revenue	**365.8**
COST (2008$/kW-year)	
Capital Cost	227.2
'Fixed O&M Cost	30.5
Total Cost	**257.7**
NET FUNDS - Available for Transmission	
Maximum Transmission Costs (2008$/kW/yr)	**108.09**
Maximum Transmission Costs (millions of 2008$)	**952**
Miles of Transmission @ $3 million/mile	**317**

This stylized example illustrates the potential relationship between the value of windpower and the cost of building transmission to deliver the energy to the rest of ISO-NE. Note that under the assumptions outlined above, the REC revenues are over 40% of the total. Of course, not all of the surplus revenue would necessarily be available for transmission construction, and 300 miles of transmission may or may not suffice to deliver energy from 1,000 MW of wind capacity to the rest of New England.

Although only a rough approximation of the magnitude of costs involved, the assumptions can be altered in the example above to examine how the outcomes might vary as a result. Table E.4 shows how much transmission could be built from windpower surplus revenues under alternative assumptions. Different wind capacity factors, capital costs, and REC prices all can impact the surplus available for transmission investment, which varies from $460 million to $1,452 million – corresponding to 150 miles to nearly 500 miles of transmission under an assumed $3 million per mile cost. This illustrates some of the risks of combined windpower/transmission resource development. As expected, the performance of the wind generation (measured by capacity factor) affects revenues significantly, and the construction costs have a significant impact on the overall project economics. But the REC price received by the wind developers also has a strong effect on the project economics – and that poses unique risks insofar that the amount of

generation (and RECs) available from the project itself could affect REC prices throughout the region. At a 32% capacity factor, a 1,000 MW wind project will generate about 2,800 GWh per year. If that were enough to turn a regional REC deficit into a surplus, then REC prices could fall – imperiling the overall project economics.

Table E.4: Transmission Investment from Windpower Net Revenues Under Alternative Assumptions

Variable	Value	Total Cost of New Transmission (in millions; $2008)	Miles of Transmission Feasible (miles)
Base	No Change	952	317
Annual Capacity Factor	30%	769	256
Annual Capacity Factor	35%	1261	420
Overnight Cost	$1750/kW	1202	401
Overnight Cost	$1500/kW	1452	484
Renewable Energy Credit	$45.00	706	235
Renewable Energy Credit	$35.00	460	153

Because a large project combining wind and transmission would face significant risks, a regional approach to renewable resource development may become necessary to realize the aggregate goals of New England RPS targets. The economics of such investments may prove attractive enough to pursue, although much more study will be required to outline the risks, equitably allocate costs and benefits, and identify specific transmission projects and wind resources. For example, there are other potential benefits that could help justify transmission expansion in northern New England, such as reliability, access to unused summer peaking capacity in Southeastern Canada, enhanced market competitiveness, and economic development. Evaluating such benefits is outside of the scope of this study but should be addressed in detail as specific projects are considered.

VI. Availability and Cost of Renewable Electric Generation in Connecticut

Although a thorough examination of renewable energy potential in New England is beyond the scope of this report, we consider – on a high level – the costs and availability of several Class I and Class II renewable resources in Connecticut. Primary renewable technologies, for which we

calculate a levelized cost of electricity, include wind, solar photovoltaic, biomass, landfill methane gas, and fuel cells. Other renewable resources are screened out based on the unavailability of resources — unexploited or entirely absent — in Connecticut, or on the basis of the technological immaturity. Theses technologies include geothermal, solar thermal, hydropower, wave, and tidal.

i. Primary Renewables in Connecticut

Wind, solar photovoltaic, biomass, landfill methane, and fuel cells (although commercial fuel cells operate on natural gas) qualify as a Class I resource in the Connecticut RPS; as such, we characterize and estimate the levelized cost of electricity from these renewable technologies. The cost and performance characteristics of these technologies are based on the review of several sources, including the ISO-NE's 2007 "Scenario Analysis" and the EIA's "Annual Energy Outlook 2007". Table E.5 illustrates the renewable technology generation characteristics, based on current technology, assumed in this analysis. Overnight costs reflect unit siting in New England.

Table E.5: Renewable Technology Generation Characteristics (Current Technology).

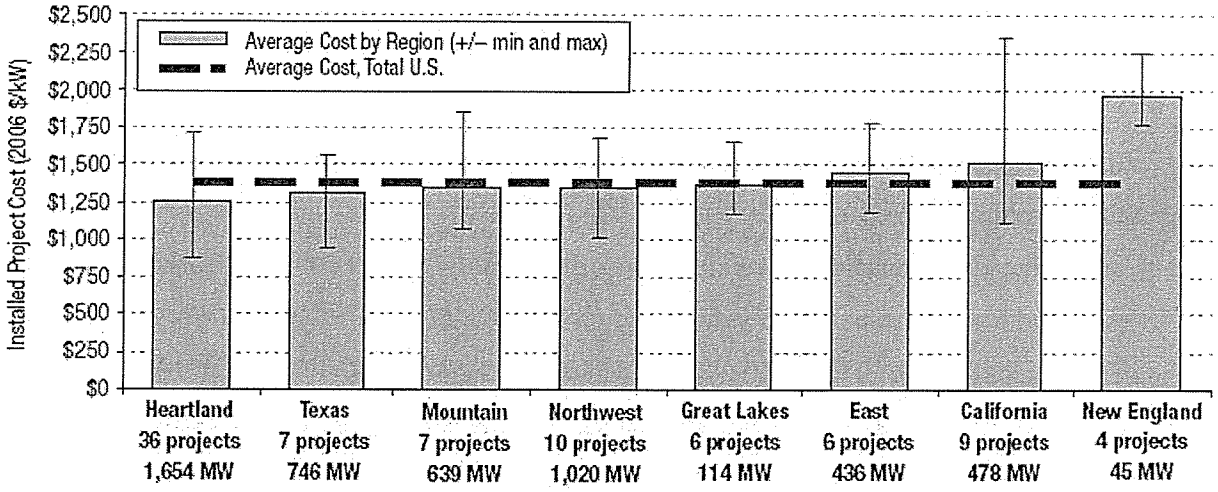
Parameter	Units	Wind	Solar Photovoltaic	Biomass	Landfill Methane Gas	Fuel Cell
Overnight Cost	(2008$/kW)	2,000	5,237	3,142	2,356	3,927
Fixed O&M	(2008$/kWyr)	30.5	11.9	54.1	115.9	5.7
Variable O&M	(2008$/MWh)	0.0	0.0	3.2	0.0	48.6
Economic Life	(Years)	20	20	20	20	20
Capital Charge Rate	(%)	11.4%	11.3%	12.1%	11.6%	11.6%
Fuel Type	(type)	Renew	Renew	Woodchips	Renew	Gas
Heat Rate	(Btu/kWh)	0	0	14,000	10,500	8,000
CO2 Emissions	(tons/MWh)	0.00	0.00	1.08	0.00	0.44
Assumed Capacity Factor	(%)	30%	16%	85%	85%	90%

Notes: Emissions are in metric tonnes.

Construction costs are higher in New England relative to other regions of the US. The Department of Energy's "Annual Report on Wind Power Installation, Cost, and Performance

Trends: 2006" illustrates this cost differential. Specifically, Figure E.1 below, from the DOE report, illustrates higher wind project costs in New England.[6]

Figure E.1: Regional Installed Wind Project Costs



Source: Berkeley Lab database.

Fuel costs and emissions allowances are relevant to fuel cells and biomass in our analysis. Fuel cells are assumed to operate on natural gas, while biomass is assumed to combust woodchips. Natural gas costs and emissions costs used in the renewable technology analysis are based on levelized equivalents to the fuel and emission cost trajectories (from 2008 through 2030) from the Current Trends scenario. The cost of woodchips is derived from the ISO-NE's Scenario Analysis. Although landfill methane gas operates on methane, we assume it to have zero fuel costs, given that methane gas is freely available as a waste byproduct from landfills. Additionally, landfill methane gas is assumed to be carbon neutral, as its emissions do not add to what is all ready emitted by landfills.

All-in costs for Connecticut are evaluated at 30% capacity factor for wind, 16% for solar photovoltaic, 85% for biomass and landfill methane, and 90% for fuel cells. Capacity factors for wind and solar photovoltaic depend on regional environmental conditions. The capacity factors

[6] See Figure 20, p. 16 in the "Annual Report on Wind Power Installation, Cost, and Performance Trends: 2006" US Department of Energy, 2007.

assumed for wind and solar photovoltaic in our analysis reflect environmental conditions in Connecticut.

Figure E.2 below illustrates the results of the all-in cost analysis for renewable technologies. Federal production tax credits for eligible technologies are reflected in the capital costs in this graph, although they actually are related to generation (production) levels. Table E.6 shows the effect of the Production Tax Credit (PTC) on renewable generation costs.

Figure E.2: Levelized Electricity Cost for Renewable Technologies

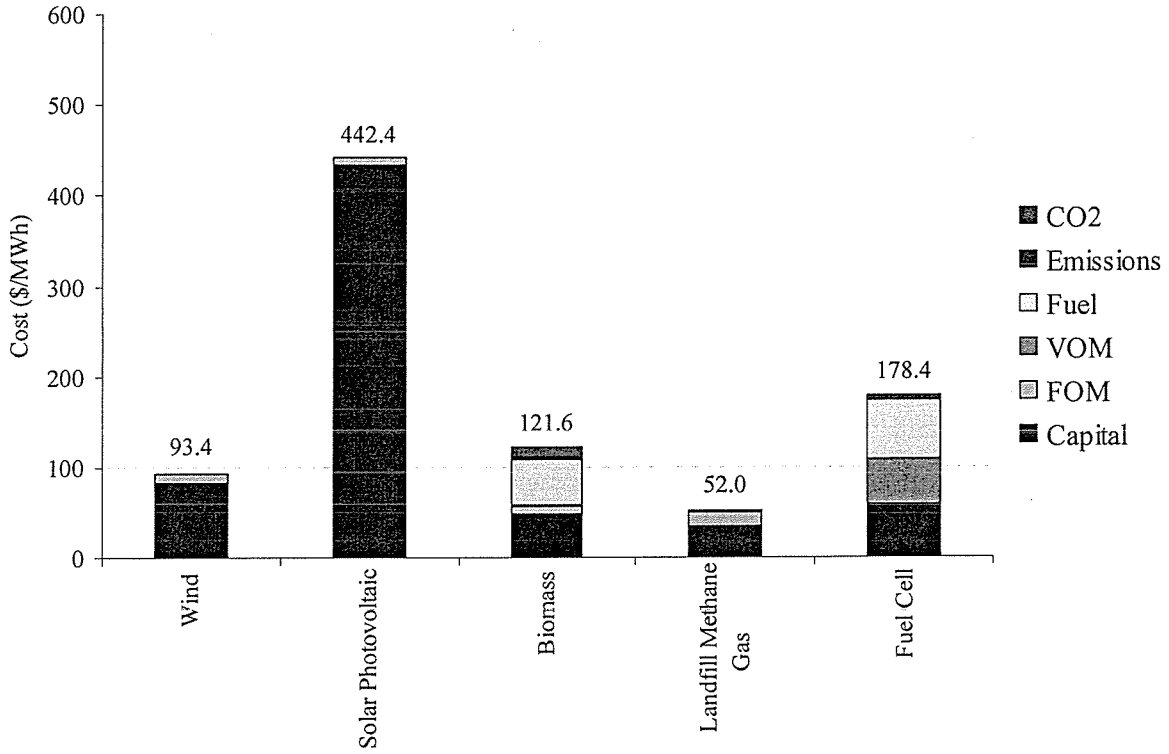


Table E.6: Levelized Electricity Cost for Renewable Technologies Including PTC

Renewable Resource	Connecticut RPS Class (Class)	LCOE (2008$/MWh)	PTC (2008$/MWh)	LCOE After PTC (2008$/MWh)
Wind	1	100.2	6.8	93.4
Solar Photovoltaic	1	449.3	6.8	442.4
Biomass	1	125.0	3.4	121.6
Landfill Methane Gas	1	55.4	3.4	52.0
Fuel Cell	1	178.4	0.0	178.4

Under these cost assumptions, wind, landfill methane, and biomass appear roughly cost competitive against current market prices assuming REC prices of $50/Mwh. However, the availability of these resources in Connecticut will limit their potential contribution to RPS compliance.

Wind resource potential is limited in Connecticut, and is concentrated in the northwest portion of the State. A 2007 study by Levitan & Associates Incorporated cited one estimate of the potential for onshore wind generation in Connecticut at only 43 MW.[7] The best wind resources in New England are offshore and further north, especially Maine. However, offshore wind projects are extremely controversial and much more expensive, and generally not considered viable over the next decade. Landfill Methane Gas potential is less than 20 MW; most sites have been exploited; other landfills are not highly-feasible candidates. This is confirmed in the EPA's Landfill Methane Outreach Program (LMOP) database.[8]

ii. Other Renewable Technologies

Geothermal

Geothermal electric generation is not eligible for contributing to the Connecticut RPS, although it is eligible in Maine, Rhode Island and New Hampshire (Class I). On this basis alone, geothermal is not a relevant candidate for cost considerations. Furthermore, New England does not feature conventional geothermal resource suitable for hydrothermal generation based on

[7] See "Technical Assessment of Onshore and Offshore Wind Generation Potential in New England" prepared by Levitan & Associates (May 1, 2007) Table 8.

[8] See "Landfill Gas Energy Projects and Candidate Landfills" map from the Environmental Protection Agency at:

current technology, nor does it offer potential for economical implementation of enhanced hydrothermal generation systems such as "hot dry rock" water injection and heat recovery.[9]

A recent study estimated costs for enhanced geothermal system generation at a site in New Hampshire. Using current technology, the study finds costs ranging from $340 to $680 per MWh; clearly, this technology is uneconomic compared to alternatives. However, the study finds that under advanced technology scenarios, costs may fall to a range of $83 to $92 per MWh. Nevertheless, such technology developments will take decades to achieve.[10]

Wave, Tidal, and Ocean Thermal

Technologies utilizing Wave, Tidal, and Ocean Thermal resources are in relatively early stages of research and development, and are not yet widely commercial in the US. Furthermore, ocean resources near Connecticut offer little in the way of electric generation potential based on current technology.[11] In California, where generation potential from ocean resources is much more abundant, costs are still extremely prohibitive.[12] Analogously, ocean energy, based on current technology, is not considered economical in Connecticut.

Solar Thermal

Solar thermal electricity generation is only feasible in selected areas of the U.S. southwest, where solar insolation rates can reach 6.0 kW-hr/m2/day or higher. In comparison, NE insolation rates typically fall below 4.0 kW-hr/m2/day.[13]

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[9] See Table A.2.1 of Chapter 2—Appendix A. "The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century" by Massachusetts Institute of Technology. 2006.

[10] See Table 1.3, p.1-29. "The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century" by Massachusetts Institute of Technology. 2006.

[11] An EPRI study on tidal resources available near Massachusetts suggests that other regions of the US and Canada offer significantly better tidal resources. See "North America Tidal In-Stream Energy Conversion Technology Feasibility Study"; EPRI TP-008-NA by Electric Power Research Institute. June 11, 2006.

[12] The levelized cost of electricity for a 750 MW wave resource plant owned by an independent utility is approximately $846.60 per MWh in nominal dollars; see Table 4 in "Comparative Costs of California Central Station Electricity Generation Technologies"; CEC-200-2007 011-SD; by the California Energy Commission. June 2007.

[13] See Figure 13.5 in "Power Technologies Data Book, 4th Ed" by National Renewable Energy Laboratories. August 2006.

Hydropower

Most sites with feasible generation capacity in Connecticut are developed. Other potential sites either are not economically feasible, or the costs are not known until development interest emerges.

APPENDIX F: CO_2 REDUCTION POLICIES

Emerging concerns regarding climate change have focused on the electric power sector in the U.S. In New England, a regional program to address CO_2 emissions from power plants, the Regional Greenhouse Gas Initiative (RGGI) will take effect in 2009. The U.S. Congress is actively debating proposals to restrict CO_2 emissions from all sectors of the economy. While it is not possible to accurately predict the level and economic impacts of eventual national CO_2 policy, it is important to consider the prospects of such policies in utility resource planning analysis.

I. REGIONAL GREENHOUSE GAS INITIATIVE (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a market-based program designed to reduce CO_2 emissions in the Northeast and Mid-Atlantic states. The program targets fossil fuel-fired electricity generating units with a capacity of at least 25 MW, and it implements a regional CO_2 emissions cap and allowance trading program.[1] RGGI is the first regional greenhouse gas emissions reduction program and the first mandatory greenhouse gas allowance trading system in the U.S.

RGGI was first proposed in April 2003 and will begin implementation on January 1, 2009. Ten states, including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, have agreed to participate in the program. RGGI set the regional base for the annual CO_2 emissions budget for the ten states at 188,076,983 tons, and apportions CO_2 emission allowance budgets to each state. The state budgets remain unchanged between 2009 and 2014. Beginning in 2015, each budget declines by 2.5% of the original budget per year so that each state's budget in 2018 is 10% below its initial budget. Table F.1 below shows the RGGI emission budgets for ISO-NE states in 2011, 2013 and 2018.

[1] There is no definitive list of RGGI affected units, as the original state budgets were based on a preliminary list, and the criteria for plant selection remains somewhat ambiguous because it uses original "nameplate" capacity ratings which can be different from more recent capacity measures, and applies to units that use more than 50% fossil fuel, which may vary over time.

Table F.1: RGGI State Emissions Budgets by Year (CO_2 Emissions in Short Tons)

	2011	2013	2018
CT	10,695,036	10,695,036	9,625,532
ME	5,948,902	5,948,902	5,354,012
MA	26,660,204	26,660,204	23,994,184
NH	8,620,460	8,620,460	7,758,414
RI	2,659,239	2,659,239	2,393,315
VT	1,225,830	1,225,830	1,103,247
New England Total	55,809,671	55,809,671	50,228,704

Since RGGI is a 10-state regional cap, compliance is not mandatory for any given source or even at the statewide level, provided that sufficient allowances can be obtained from other sources in states with emissions below their allocated budget. It is possible that aggregate CO_2 emission from affected units in the 10-state region will be slightly below the 188 million ton budget level in 2009. Analysis of the six New England states suggests that as a sub-region in RGGI, New England initially will be in surplus because emissions will be below the combined budgets of the New England states.[2]

Because states have not allocated or auctioned any allowances, the price for RGGI allowances is not known at this time. Even if the entire RGGI region (or just the New England portion) were in an initial surplus, however, one would expect that positive prices would emerge from initial auctions because the allowances are tradable across the RGGI region and bankable for future use. Unfortunately, past analyses that have estimated RGGI allowance prices were conducted during a time when states were still joining (or planning to join) the RGGI program. For example, the most recent estimate from RGGI was for the 7-state region (*e.g.*, before MA, RI and MD officially joined) and examined a 121 million ton budget.[3] The most recent analysis of which we are aware was commissioned by the State of Maryland, which looked at joining the 7-state region but did not examine the 10-state region because it was conducted prior to Massachusetts

[2] *Evaluation of Impact of regional Greenhouse Gas Initiative CO_2 Capon the New England Power System*, ISO-NE, October 26, 2006.

[3] See "RGGI Preliminary Electricity Sector Modeling Results: Phase III RGGI Reference and Package Scenario" ICF Consulting, August 17, 2006.

and Rhode Island formally joining the program.[4] The NE-ISO study of October 2006 considered the prospects of Massachusetts and Rhode Island joining the other New England RGGI states, but did not estimate allowance prices because it instead examined the impacts of a range of assumed allowance prices on the region's emissions and energy prices. Lacking a definitive study, we derived our assumed RGGI allowance prices from the Maryland study, because this study was the most recent, and thus incorporated more recent fuel prices in its estimates. These prices were $4.85 per ton of CO_2 in 2011 and $5.69 per ton of CO_2 in 2013 (converted to 2008 dollars).[5] By 2018, we assume that RGGI program is supplanted by a federal program with higher allowance prices than expected under RGGI, except for in the Strict Climate Scenario, where the Federal program becomes effective by 2013.

In this study, we have modeled compliance with RGGI from a financial perspective, *e.g.*, the dollar value of allowances that are implied by each covered source's CO_2 emissions. That is, we allocate a CO_2 price to each affected fossil-fuel generation unit in proportion to its CO_2 emissions, and that becomes part of the variable cost of dispatch. This is a correct way of modeling costs even when allowances are allocated freely (although there will be differences between cost-of-service ratemaking and unregulated generators' rate impacts). In the case of Connecticut, however, the state has announced its intention to auction off 100% of the RGGI budget allowances, which would clearly make CO_2 both an expense from the standpoint of an unregulated generator as well as a cost from the standpoint of a cost-of-service price.

II. Federal Climate Policy

This study assumes that a market-based national climate policy will emerge early in the next decade, which will be more stringent than the RGGI targets and which will result in a CO_2 allowance price that is higher than prices assumed under RGGI.

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[4] See *Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative*, A Study Commissioned by the Maryland State Department of the Environment, January 2007.

[5] These were derived from interpolating the figures in Table 9.10 under the "Maryland Joins RGGI" column for 2010 and 2015, and converting from $2004 to $2008.

While the emergence of a federal CO_2 policy is plausible, and even probable in the timeframe we consider, it is too early in the debate to make accurate predictions regarding the level and timing of the emission reductions, the presence or absence of cost-containment mechanisms such as allowance price caps ("Safety Valve Price") or international offsets, and therefore the resultant CO_2 prices. Nevertheless, we assume that a market-based allowance program will be in place by the middle of the next decade in all scenarios, except for the Strict Climate scenario where the federal program will be in effect by 2013.

One of the primary debates regarding policy is the issue of whether a "safety valve" price should be included. A safety valve is a cap on the price of CO_2 emissions: at this price, the government will issue additional CO_2 allowances and thereby permit emissions to exceed the overall target. Absent a safety valve, allowance prices are both uncertain (it is not possible to estimate the initial levels easily) and potentially volatile (they will be prone to frequent changes as fuel prices and other costs change over time). A safety valve set at a high level (i.e., much higher than the expected price) may only rarely come into play, while a safety valve set at a relatively low level (i.e., closer to the "expected price") will probably determine the CO_2 allowance price most or all of the time.

Although we are not predicting whether or not an actual safety valve price will be utilized, we used the "safety valve" prices contained in recent legislation to guide our CO_2 allowance price assumptions in the Current Trends scenario. In the Current Trends scenario, we assume that the CO_2 allowance price will follow the safety valve price featured in the Bingaman-Specter Low Carbon Economy Act of 2007. In the Bingaman-Specter bill, the safety valve price begins at \$12/ton of CO_2 (in 2012\$) and grows at 5% in real terms. This yields approximately \$13/ton in 2018 and \$24/ton in 2030 (all in 2008\$). We assume that this allowance price path does not begin until after 2013, however, so that it only affects the 2018 and 2030 analysis years (RGGI prices are assumed for the 2011 and 2013 in the Current Trends scenario). This is also the assumption in the Lower Stress scenario.

In the Strict Climate scenario, we assume that (1) federal climate policy begins earlier, and thus is in effect by 2013, and (2) that the level of emission reductions sought are much more

aggressive than the levels determined by the safety valve price contained in the Bingaman-Specter proposal.[6] For the Strict Climate scenario, we assumed implementation of a climate policy similar to S.280, the Climate Stewardship and Innovation Act of 2007, introduced into the 110th Congress by Senator Leiberman on January 12, 2007. S.280 contains a set of economy-wide CO_2 emission targets, which return to 2004 levels by 2012, fall to their 1990 levels by 2020, and in the long run (*e.g.*, 2050) are 60% below the 1990 levels. Up to 30% of emission reductions can arise from international offsets from CO_2 emission reductions pursued abroad, and the proportion of domestic CO_2 allowances that are auctioned (rather than distributed free to affected entities) is gradually increased. Because S.280 did not have a safety valve allowance price cap, however, allowance prices are uncertain. Analyses by the Energy Information Administration and the Environmental Protection Agency suggest a wide range of possible CO_2 allowance prices under S.280. These CO_2 prices will depend upon fuel prices, energy demands, the cost and availability of nuclear power, the cost and availability of carbon capture and storage (CCS) technologies for coal-fired generation, and the cost and availability of international offsets that can be substituted for domestic emission reductions. Projections of CO_2 allowance prices in the early years (i.e., 2012 to 2015) range from about $10 to $40 per ton, with the low end of the range roughly similar to the Bingaman-Specter safety valve price. Projections of CO_2 allowance prices for the 2030 timeframe range from below $30 to over $80 per ton.

Since the scenario analysis is designed to explore significant differences in external factors, we selected an allowance price path that was on the high end of the range of the overall set of projections. In doing so, we are not predicting such CO_2 prices, but rather examining the impact on resource decisions from an aggressive national CO_2 policy that does not benefit from optimistic technology or international offset assumptions.[7] This results in a much higher CO_2 price in 2013 than other scenarios ($25/ton compared with less than $6/ton in other scenarios, in year 2008 dollars); however the ratio narrows over time from over four times as high to roughly double. The CO_2 allowance price in 2018 is about $31/ton in the Strict Climate scenario (vs.

[6] See *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, (EIA, July 2007) and *EPA Analysis of The Climate Stewardship and Innovation Act of 2007* (EPA, July 16, 2007).

[7] We chose the allowance price projections derived from Scenario 6 from the EPA analysis, which assumes a lower growth rate in nuclear power generation than other EPA scenarios.

$13/ton in the Current Trends and Low Stress scenarios) and $55/ton in 2030 (vs. $24/ton in the Current Trends and Low Stress scenarios). In the High Fuel/Growth Price scenario, the 2018 and 2030 prices are assumed to be one-third higher than in the Current Trends scenarios. The Table below shows the assumed CO_2 allowance prices assumed in the study.

Table F.2: CO_2 Emissions Permit Prices by Scenario (Short Tons)

Year	Current Trends (2008 $/tCO2)	Strict Climate (2008 $/tCO2)	High Growth& Fuel Prices (2008 $/tCO2)	Low Stress (2008 $/tCO2)
2011	4.85	4.85	4.85	4.85
2013	5.69	25.05	5.69	5.69
2018	13.32	30.92	17.76	13.32
2030	23.92	54.80	31.90	23.92

APPENDIX G: DAYZER MODEL INPUT ASSUMPTIONS

I. INTRODUCTION

The analysis of energy production, costs, and emissions was performed using the DAYZER model. DAYZER is an electricity market simulation model designed by Cambridge Energy Solutions (CES) to mimic ISO-NE's operation of the New England electricity market. The model takes as inputs the fundamental elements of supply, demand, and transmission; the outputs include generation outputs, costs, prices, transmission flows, and emissions. Although CES provides a complete set of data that can be used as model inputs, *The Brattle Group* refined and developed the data to better reflect current and expected ISO-NE market conditions for the purpose of this study. This appendix describes the resulting data inputs and key assumptions.

II. SIMULATION CASES

Each DAYZER simulation case incorporates a combination of (1) market assumptions, including load growth, capacity online, and the price of fuel and emission allowances, which vary by scenario; (2) the degree of inclusion of the New England East-West Solution (NEEWS) transmission project; and (3) a candidate resource solution to meet any resource gap relative to reliability requirements. Varying these factors to test each resource solutions across a range of market and system conditions yields numerous possible combinations and, hence, numerous potential simulations. Figure G.1 presents the dimensions in any given simulation case. Each dimension has an abbreviated name found in the DAYZER input and output files, and a corresponding description for clarification. Note that the Coal resource solution in italics does not require separate simulations for evaluation. The Coal resource solution is evaluated by making adjustments to the Nuclear resource solution simulation results.

Figure G.1: Summary of Simulation Case Dimensions

#	DAYZER Short Name	Description
Scenario: Exogenous System Condition		
1	REF(CurrTrends)	Current Trends Scenario
2	SCE1(StrictClimate)	Strict Climate Scenario
3	SCE2(HighGrowth)	High Fuel/Growth Scenario
4	SCE3(LowStress)	Low Stress Scenario
Resource Solution: Evaluated Companies Resource Solution		
1	IRP1(Conv)	Conventional Approach
2	IRP2(HvyDSM)	DSM-Focus Solution
3	IRP3(BaseGen)	Nuclear Solution (Simulated in Study Years with Resource Gap Only)
4	*IRP3a(BaseGen-Coal)*	*Coal Solution - Coal (Not Simulated)*
Study Year: Subject to Variations on New England East-West Solution Transmission Inclusion		
1	2011	
2	2013	
3	2018	
4	2030	
Degree of New England East-West Solution Transmission Inclusion		
1	nNEEWS	No NEEWS (2011 Only); Includes Middletown/Norwalk project
2	pNEEWS	Partial NEEWS (2013, 2018, and 2030 Only); Excludes Central Connecticut Reliability Component
3	tNEEWS	Total NEEWS (2013, 2018, and 2030 Only)

III. General Model Assumptions

The model assumes a competitive market in which energy bids are based on incremental costs. Incremental costs are assumed to be given by the incremental heat rate + variable O&M costs, without regard to potential opportunity costs. However, the unit commitment algorithm that precedes the generation dispatch also considers unit startup costs, minimum up time, and other operating constraints, as described in Appendix A.

IV. Existing Capacity

Existing capacity as of 2007 is generally consistent with the ISO-NE 2007 Regional System Plan (RSP) and the 2007 Capacity, Energy, Loads, and Transmission (*CELT*) report.[1] Figure G.2 summarizes ISO-NE existing generating unit capacity used in the DAYZER model compared to the 2007 RSP and the *CELT* report.

[1] However, capacity in the supply-demand balance used for defining the resource gap is exactly consistent with CELT. Please see Table 2.2 of the main report.

Figure G.2: ISO-NE Existing Generating Unit Capacity by State

State	Total Installed Capacity (MW)	
	Assumed Existing Capacity	2007 Regional System Plan
Connecticut	7,552	7,535
Maine	3,199	3,084
Massachusetts	13,213	13,027
New Hampshire	3,991	3,979
Rhode Island	1,803	1,818
Vermont	877	1,084
Total	30,636	30,527
CELT		30,945

As shown in Figure G.2, the Connecticut capacity in the DAYZER model is 7,552 MW, which is almost the same as the 7,535 MW reported in the RSP. Both numbers include the approximately 700 MW Lake Road units which are located geographically in Connecticut, but electrically in Rhode Island. The *CELT* report shows Connecticut existing capacity as 6,999 MW not including the Lake Road units, and 7,697 MW including the Lake Road units (i.e., within 200 MW of the capacity listed in RSP and DAYZER).

Outside of the DAYZER model, in our determination of the resource needs relative to Connecticut's local sourcing requirement (LSR), we used CELT's 6,999 MW until the NEEWS transmission project brings Lake Road electrically into Connecticut, as shown in Table 2.3. Further clarification on the Connecticut units and ratings used in this study to define the Connecticut resource needs (according to the *CELT* report) are shown in Figure G.3.

Figure G.3: *CELT* Existing Generating Units in Connecticut Area

CELT Generator Name	Area	Summer Capacity *(MW)*
MILLSTONE POINT 3	CT	1,155
MILLSTONE POINT 2	CT	880
NEW HAVEN HARBOR	CT	448
MONTVILLE 6	CT	407
MIDDLETOWN 4	CT	400
MIDDLETOWN 3	CT	236
AES THAMES	CT	181
MIDDLETOWN 2	CT	117
MONTVILLE 5	CT	81
CDECCA	CT	52
SO. MEADOW 13	CT	38
DEXTER	CT	38
SO. MEADOW 12	CT	38
SO. MEADOW 14	CT	37
SO. MEADOW 11	CT	36
PFIZER #1	CT	33
SO. MEADOW 6	CT	27
SO. MEADOW 5	CT	26
UCONN COGEN	CT	25
EXETER	CT	24
PRATT & WHITNEY (UTC)	CT	24
US NAVAL SUBMARINE BASE	CT	19
MIDDLETOWN 10	CT	17
SECREC-PRESTON	CT	16
TUNNEL 10	CT	16
TORRINGTON TERMINAL 10	CT	16
FRANKLIN DRIVE 10	CT	15
NORWICH JET	CT	15
BRISTOL REFUSE	CT	13
LISBON RESOURCE RECOVERY	CT	13
AGGREGATE UNITS <10 MW	CT	90
NORWALK HARBOR 2	NOR	168
NORWALK HARBOR 1	NOR	162
WATERSIDE POWER	NOR	70
COS COB 10	NOR	19
COS COB 12	NOR	18
COS COB 11	NOR	18
NORWALK HARBOR 10 (3)	NOR	12
AGGREGATE UNITS <10 MW	NOR	3
BRIDGEPORT ENERGY 1	SWCT	448
BRIDGEPORT HARBOR 3	SWCT	372
MILFORD POWER 2	SWCT	253
MILFORD POWER 1	SWCT	239
BRIDGEPORT HARBOR 2	SWCT	130
BRIDGEPORT RESCO	SWCT	59
PPL WALLINGFORD UNIT 3	SWCT	44
PPL WALLINGFORD UNIT 1	SWCT	44
PPL WALLINGFORD UNIT 4	SWCT	43
PPL WALLINGFORD UNIT 5	SWCT	43
SHEPAUG	SWCT	42
PPL WALLINGFORD UNIT 2	SWCT	41
DEVON 13	SWCT	31
DEVON 14	SWCT	30
DEVON 11	SWCT	30
ROCKY RIVER	SWCT	29
DEVON 12	SWCT	29
STEVENSON	SWCT	28
BRANFORD 10	SWCT	16
DEVON 10	SWCT	14
AGGREGATE UNITS <10 MW	SWCT	33
Total		**6,999**

Source: CELT file "2007-celt_spreadsheets.xls."
See http://www.iso-ne.com/trans/celt/report/index.html.

V. Generating Unit Retirements

Only one unit that is included in Table G.2 is assumed to retire: New Boston 1, a 350 MW unit in the NEMASS/Boston zone.[2] Coal units are assumed to have indefinite life, and nuclear units are assumed to receive 40-year NRC license extensions, which makes all nuclear units operable through 2030. Other units are assumed to stay online, based on the preliminary screening analysis described in Appendix A.

VI. Planned Unit Additions and Upgrades

1,107 MW of planned unit additions and upgrades that are recently completed, currently under construction, or under contract are assumed to come online by 2011, as summarized in Figure G.4. In addition, 279 MW of combustion turbines are assumed to be added to meet the local forward reserve requirement in Connecticut, as described in Appendix A.

Figure G.4: ISO-NE Planned Generating Unit Additions and Expansions by 2011

Unit Name	Unit Type	Zone	Summer Capacity (MW)	Winter Capacity (MW)	Fuel Name
UNIT ADDITIONS					
Waterbury	New CT	South Western CT Zone	80	96	Natural Gas
Kleen Energy	New CC	Rest of CT Zone	560	620	Natural Gas
Wallingford/Pierce	New CT	South Western CT Zone	100	100	Natural Gas
DG Capital Grant Projects	New CT	CT Zones	96	96	Natural Gas
Renewable Energy Contracts	ST	South Western CT Zone	75	75	Biomass
Renewable Energy Contracts	ST	Rest of CT Zone	75	75	Biomass
UNIT EXPANSIONS					
Cos Cob Expansion	GT	Norwalk- Stamford Zone	40	40	FO2
Millstone Point 3	NU	Rest of CT Zone	81	81	Uranium
		Connecticut Total	**1,107**	**1,183**	

The DG Capital Grant projects are small (<70 MW) projects estimated by the Companies.[3] All DG Capital Grant projects are derated by a 50% attrition rate to account for the risk that some

[2] Based on New Boston's permanent de-list bid submitted to ISO-NE in 2007.
[3] Based on a list of these projects as of 8/24/07.

projects may not come online as expected. In addition to the 96 MW included on the supply side (as shown in Figure G.4) 34 MW of the DG Capital Grant projects are implemented as load reductions. The supply-side units are combined into aggregate units by zone for simplicity. The Renewable Energy Contracts units refer to the 150 MW of renewable energy contracts the Companies are required to sign by state law, and are also implemented in the model as aggregate units by zone.

VII. Future Unplanned Capacity

The future capacity that is added to the model depends on the resource solutions being evaluated:

- In the Conventional Gas resource solution, only gas-fired CCs and CTs are added;
- In the Nuclear resource solution a 1,200 MW nuclear unit is added at the Millstone station, although it is meant to represent any brownfield nuclear site in New England. This unit, named "Millstone 4," is installed as of January 1, 2015, is assigned the unit characteristics of Millstone 3, with the exception of a heat rate lowered to reflect an assumed "learning curve;"
- The Coal resource solution is not simulated separately; it is evaluated by making adjustments to the Nuclear resource solution simulation results; and
- In the DSM-Focus resource solution, additional DSM is added to the already aggressive amount of DSM assumed in all of the resource solutions. DSM is modeled as demand reductions, the additional amount being +160 MW/ 370 GWh in 2011, +320 MW / 1000 GWh by 2013, +600 MW / 2600 GWh in 2018, and with no further growth as a percentage of load by 2030, as described in Appendix D.

Apart from the candidate resources described above, additional unplanned gas-fired CCs and CTs are added with each "resource solution" as needed to meet any resource gap relative to the ISO-NE installed capacity requirement.[4] (The resource gap varies by scenario, as summarized in Tables 2.2 and 2.3 in the main report). Unplanned new capacity is added to the model in 300 MW increments, and the technology and location are selected based on economics, i.e., with the

[4] No capacity was added specifically to satisfy the Connecticut local sourcing requirement because no additional resources were needed in any scenario, as shown in Table 2.3.

lowest all-in cost net of energy revenues. The selection of locations accounts for locational differences in construction costs, as discussed in Appendix C. For simplicity, all future unplanned units are added to major 345 kV substations and are given generic unit characteristics by unit type as shown in Figure G.5.[5]

Total unplanned new capacity amounts by type for each scenario/resource solution combination are summarized in Figure G.6.

Figure G.5: Unplanned Generating Unit Characteristics by Unit Type

Unit Type	Must Commit = 1	Must Run = 1	Planned Outage Rate (%)	Heat Rate (Btu/kWh)	Variable O&M ($/MWh)	NOx Rate (Lbs/MMBtu)	SOx Rate (Lbs/MMBtu)	CO2 Rate (Lbs/MMBtu)
New CC	0	0	4.1%	7,000	2.5	0.020	0.001	116
New CT	0	0	9.1%	10,200	5	0.020	0.001	116
Nuclear	0	1	1.4%	10,207	1.8	0	0	0

[5] All costs and prices have been converted to real 2008 dollars using a 2.3% inflation rate, unless otherwise noted. This inflation rate is based on forecasted Consumer Price Index in *Blue Chip Economic Indicators*, Long-Range Consensus U.S. Economic Projections, March 10, 2007.

Figure G.6: Unplanned New Capacity by Unit Type and Scenario/Resource Solution Combination

	Gross Cumulative Unplanned Generic Capacity Added (MW)												Totals by Year (MW)			
	2011			2013			2018			2030			2011	2013	2018	2030
	NCC	NGT	Baseload	NCC	NGT	Baseload	NCC	NGT	Baseload	NCC	NGT	Baseload				
TOTAL ISO																
Current Trends Scenario																
Conventional	-	-	-	-	-	-	1,500	-	-	5,700	1,500	-	-	-	1,500	7,200
DSM-Focus	-	-	-	-	-	-	900	-	-	5,700	600	-	-	-	900	6,300
Nuclear	-	-	-	-	-	-	300	-	1,200	5,400	600	1,200	-	-	1,500	7,200
Strict Climate Scenario																
Conventional	-	-	-	-	-	-	1,200	-	-	5,700	900	-	-	-	1,200	6,600
DSM-Focus	-	-	-	-	-	-	300	-	-	5,100	600	-	-	-	300	5,700
Nuclear	-	-	-	-	-	-	-	-	1,200	4,800	600	1,200	-	-	1,200	6,600
High Fuel/Growth Scenario																
Conventional	-	-	-	600	-	-	3,000	600	-	7,800	1,500	-	-	600	3,600	9,300
DSM-Focus	-	-	-	300	-	-	2,400	300	-	6,900	1,500	-	-	300	2,700	8,400
Nuclear	-	-	-	-	-	-	2,400	-	1,200	6,600	1,500	1,200	-	-	3,600	9,300
Low Stress Scenario																
Conventional	300	-	-	1,500	-	-	3,900	600	-	9,000	1,500	-	300	1,500	4,500	10,500
DSM-Focus	-	-	-	1,200	-	-	3,300	600	-	8,100	1,500	-	-	1,200	3,900	9,600
Nuclear	-	-	-	-	-	-	2,700	600	1,200	7,800	1,500	1,200	-	-	4,500	10,500
CONNECTICUT																
Current Trends Scenario																
Conventional	-	-	-	-	-	-	300	-	-	2,100	600	-	-	-	300	2,700
DSM-Focus	-	-	-	-	-	-	-	-	-	2,100	300	-	-	-	-	2,400
Nuclear	-	-	-	-	-	-	-	-	1,200	2,100	300	1,200	-	-	1,200	3,600
Strict Climate Scenario																
Conventional	-	-	-	-	-	-	300	-	-	2,100	300	-	-	-	300	2,400
DSM-Focus	-	-	-	-	-	-	-	-	-	2,100	300	-	-	-	-	2,400
Nuclear	-	-	-	-	-	-	-	-	1,200	1,800	300	1,200	-	-	1,200	3,300
High Fuel/Growth Scenario																
Conventional	-	-	-	-	-	-	1,500	300	-	3,000	600	-	-	-	1,800	3,600
DSM-Focus	-	-	-	-	-	-	900	-	-	2,700	600	-	-	-	900	3,300
Nuclear	-	-	-	-	-	-	900	-	1,200	2,700	600	1,200	-	-	2,100	4,500
Low Stress Scenario																
Conventional	-	-	-	300	-	-	1,800	300	-	3,300	600	-	-	300	2,100	3,900
DSM-Focus	-	-	-	300	-	-	1,800	300	-	3,300	600	-	-	300	2,100	3,900
Nuclear	-	-	-	-	-	-	1,200	300	1,200	3,000	600	1,200	-	-	2,700	4,800

VIII. GENERATING UNIT AVAILABILITY

a. Forecasted Maintenance Outages

Maintenance outages for each generating unit are forecasted within the DAYZER model based on load input, the assumed planned outage rate and duration for that unit, and a seasonal maintenance outage pattern. Maintenance outage rates are based on ISO-NE's recommended maintenance allotments by unit type,[6] as summarized in Figure G.8. The resulting maintenance outage schedules for all units are summarized in Figure G.7 below, along with the forecasted forced outage schedules. As Figure G.7 shows, the maintenance outages are properly concentrated in the Spring and Fall when load is the lowest, and gaps in the maintenance outage curve indicate days in which no maintenance outages occur.

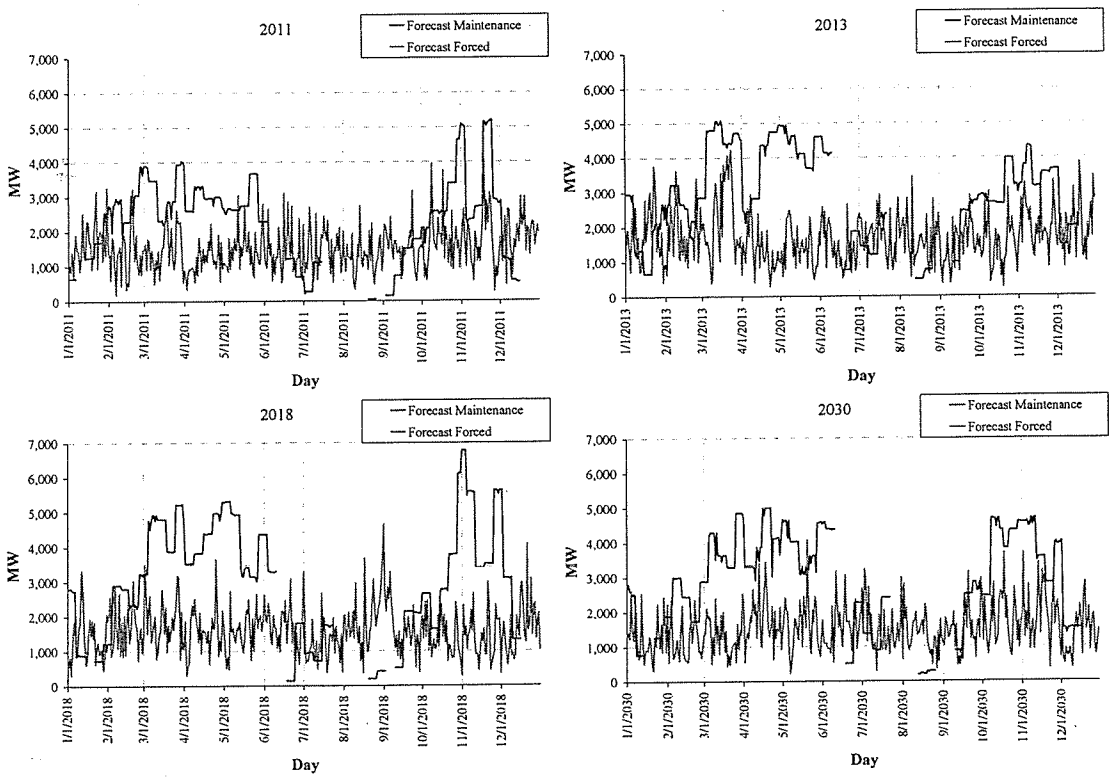
[6] *ISO New England Recommended FCM Maintenance Allotments*; 12/07/2007 Draft; Table 2.

b. Random Forced Outages

Forced outages are randomly selected by the model based on the specified forced outage rate and duration for each unit. Forced outage rates are based on the 2006 PJM State of the Market Report outage rates by unit type.[7] The panels in Figure G.7 show forecasted total ISO maintenance and forced outages assumed in each study year. Importantly, outage schedules are held constant across all resource solutions and scenarios within each study year.

Generic unplanned units are not given a forced outage schedule. These units are instead derated by their forced outage rates.

Figure G.7: Forecasted Total Maintenance and Forced Outages by Study Year



[7] *PJM State of the Market Report*, PJM Market Monitoring Unit, Volume II, Section 5 – Capacity Markets,, March 8, 2007, at Table 5-16, p. 232. See http://www.pjm.com/markets/market-monitor/som.html.

Figure G.8: Outage Rates and Durations by Unit Type

Unit Type	Final POR (%)	Final FOR (%)	Final PO Duration (Days)	Final FO Duration (Days)
CC	5.6%	4.1%	13	1
GEO	n/a	n/a	7	n/a
GT	4.6%	9.1%	12	4
GT+	4.6%	9.1%	13	2
Hydro	n/a	n/a	n/a	n/a
NCC	5.6%	4.1%	13	1
NGT	4.6%	9.1%	13	2
NU	6.5%	1.4%	24	9
PS	n/a	n/a	n/a	n/a
PUR	n/a	n/a	n/a	n/a
SOL	n/a	n/a	n/a	1
STc+	9.1%	8.2%	21	2
STc100	9.1%	8.2%	20	2
STc200	9.1%	8.2%	18	2
STg+	8.2%	8.2%	24	2
STg100	8.2%	8.2%	20	3
STg200	8.2%	8.2%	24	3
STo+	8.2%	8.2%	25	2
STo100	8.2%	8.2%	30	3
STo200	8.2%	8.2%	27	2
STr	8.2%	8.2%	14	7
WND	n/a	n/a	n/a	1

IX. Unit Characteristics

a. Dual-Fuel Units

Dual-fuel capability of steam units and combustion turbines is consistent with the ISO's 2007 *CELT* report. Dual-fuel steam units are set to burn FO6 in the winter (it is cheaper than natural gas in the winter) and are allowed to switch to gas in the summer (April through October) if gas price is less than the oil price including a 3% switching cost.[8] Dual-fuel combustion turbines with gas as the primary fuel and Distillate Fuel Oil (FO2) as the secondary fuel are allowed to switch to FO2 in January if the oil price is less than the gas price net of an assumed 5% switching cost. FO2-fired units with natural gas capability are allowed to switch to gas year-round due to the consistently lower price of projected natural gas prices. Figure G.9 summarizes all dual-fuel units by unit type.

[8] Dual-fuel steam units with gas listed as the primary fuel are allowed to switch to FO6 year-round, but only Kendall Steam is in this group.

b. Steam Unit Characteristics

Due to the sensitivity of the market to steam oil-fired unit flexibility and startup costs these characteristics have been more finely tuned based on historic generation patterns found in the EPA CEMS database.[9] Minimum uptime, minimum downtime, and startup energy for all steam oil-fired units are summarized in Figure G.10.

c. Other Unit Characteristics

All other units have assumed generic unit characteristics by unit type. These are summarized in Figure G.11 below.

[9] CEMS data compiled by Global Energy Decision, Inc., The Velocity Suite.

Figure G.9: Dual-Fuel Units by Unit Type

Unit Name	Primary Fuel	Alternate Fuel	Zone	State	Summer Capacity (MW)
DUAL-FUEL STEAM OIL UNITS					
NEW HAVEN HARBOR	FO6	NG	Rest of CT Zone	CT	461
BRAYTON PT 4	FO6	NG	South Eastern MA Zone	MA	435
MYSTIC 7	FO6	NG	NE MA Boston Zone	MA	555
NEWINGTON 1	FO6	NG	New Hampshire Zone	NH	400
MIDDLETOWN 3	FO6	NG	Rest of CT Zone	CT	236
CANAL 2	FO6	NG	South Eastern MA Zone	MA	553
HOLYOKE 8/CABOT 8	FO6	NG	West Central MA Zone	MA	9
HOLYOKE 6/CABOT 6	FO6	NG	West Central MA Zone	MA	9
MONTVILLE 5	FO6	NG	Rest of CT Zone	CT	81
WEST SPRINGFIELD 3	FO6	NG	West Central MA Zone	MA	101
MIDDLETOWN 2	FO6	NG	Rest of CT Zone	CT	117
* KENDALL STEAM 1 2 3	NG	FO6	NE MA Boston Zone	MA	60
DUAL-FUEL GT UNITS					
DEVON 11	NG	FO2	South Western CT Zone	CT	30
DEVON 13	NG	FO2	South Western CT Zone	CT	33
DEVON 12	NG	FO2	South Western CT Zone	CT	30
DEVON 14	NG	FO2	South Western CT Zone	CT	30
* IPSWICH #12	FO2	NG	NE MA Boston Zone	MA	1
* WATERS RIVER JET 2	FO2	NG	NE MA Boston Zone	MA	30
* WATERS RIVER JET 1	FO2	NG	NE MA Boston Zone	MA	14
* SCHILLER CT 1	FO2	NG	New Hampshire Zone	NH	17
DUAL-FUEL COMBINED CYCLE UNITES					
NEA BELLINGHAM	NG	FO2	South Eastern MA Zone	MA	265
CDECCA	NG	FO2	Rest of CT Zone	CT	51
DARTMOUTH POWER	NG	FO2	South Eastern MA Zone	MA	62
MANCHESTER 10/10A CC	NG	FO2	Rhode Island Zone	RI	141
MANCHESTER 11/11A CC	NG	FO2	Rhode Island Zone	RI	142
MANCHESTER 9/9A CC	NG	FO2	Rhode Island Zone	RI	142
ALTRESCO (pittsfield)	NG	FO2	West Central MA Zone	MA	141
MASS POWER	NG	FO2	West Central MA Zone	MA	232
NEWINGTON ENERGY	NG	FO2	New Hampshire Zone	NH	508
* STONY BROOK GT1C	FO2	NG	West Central MA Zone	MA	104
* STONY BROOK GT1B	FO2	NG	West Central MA Zone	MA	100
* STONY BROOK GT1A	FO2	NG	West Central MA Zone	MA	104

*Allowed to use alternate fuel year-round.

Figure G.10: Steam Oil Unit Characteristics

Unit Name	Zone	State	Summer Capacity (MW)	Minimum Down Time (Hours)	Minimum Up Time (Hours)	Startup Energy (MMBtu)
STEAM OIL UNITS						
YARMOUTH 4	Maine Zone	ME	609	8	11	10
NEW HAVEN HARBOR	Rest of CT Zone	CT	461	8	16	10
BRAYTON PT 4	South Eastern MA Zone	MA	435	8	18	10
SALEM HARBOR 4	NE MA Boston Zone	MA	380	8	18	10
MYSTIC 7	NE MA Boston Zone	MA	555	8	22	10
MONTVILLE 6	Rest of CT Zone	CT	407	8	22	10
NEWINGTON 1	New Hampshire Zone	NH	400	7	8	10
MIDDLETOWN 4	Rest of CT Zone	CT	400	8	24	10
MIDDLETOWN 3	Rest of CT Zone	CT	236	8	24	10
CANAL 2	South Eastern MA Zone	MA	553	8	24	10
CANAL 1	South Eastern MA Zone	MA	254	8	24	10
HOLYOKE 8/CABOT 8	West Central MA Zone	MA	9	6	10	10
HOLYOKE 6/CABOT 6	West Central MA Zone	MA	9	6	10	10
KENDALL STEAM 1 2 3	NE MA Boston Zone	MA	60	6	10	10
MONTVILLE 5	Rest of CT Zone	CT	81	6	10	10
YARMOUTH 1	Maine Zone	ME	52	6	10	10
YARMOUTH 2	Maine Zone	ME	52	6	10	10
CLEARY 8	South Eastern MA Zone	MA	26	6	10	10
WEST SPRINGFIELD 3	West Central MA Zone	MA	101	6	10	10
YARMOUTH 3	Maine Zone	ME	117	6	10	10
BRIDGEPORT HARBOR 2	South Western CT Zone	CT	130	6	15	10
MIDDLETOWN 2	Rest of CT Zone	CT	117	6	20	10
NORWALK HARBOR 1	Norwalk- Stamford Zone	CT	162	6	24	10
NORWALK HARBOR 2	Norwalk- Stamford Zone	CT	168	6	24	10

Figure G.11: Unit Characteristics by Unit Type

Unit Type	Minimum Downtime (Hours)	Minimum Uptime (Hours)	Startup Energy (MMBtu/MW)	FOR (%)	FO Duration (Days)	POR (%)	PO Duration (Days)	Spinning Reserve (%)	Quickstart Reserve (%)	AGC Reserve (%)	Ramp Up (%/Hour)	Ramp Down (%/Hour)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)
Combined Cycle	7	8	7	4%	1	6%	13	20%	0%	10%	75%	100%	2.5	21
New Combined Cycle	7	8	7	4%	1	6%	13	20%	0%	10%	75%	100%	2.5	15
Combustion Turbine	1	1	0	9%	4	5%	12	0%	100%	0%	100%	100%	7	15
Combustion Turbine >100 MW	1	1	0	9%	2	5%	13	0%	100%	0%	100%	100%	7	15
New Combustion Turbine	1	1	0	9%	2	5%	13	0%	100%	0%	100%	100%	5	5
Steam Turbine [Coal] < 100 MW	6	8	15	8%	2	9%	20	10%	0%	10%	50%	100%	3	45
Steam Turbine [Coal] < 200 MW	7	8	15	8%	2	9%	18	10%	0%	0%	25%	50%	3	35
Steam Turbine [Coal] > 200 MW	12	24	15	8%	2	9%	21	10%	0%	0%	15%	30%	1	35
Steam Turbine [Gas] <100 MW	6	10	10	8%	3	8%	20	10%	0%	10%	75%	100%	5	34
Steam Turbine [Gas] <200 MW	6	16	10	8%	3	8%	24	10%	0%	10%	35%	100%	4	30
Steam Turbine [Gas] > 200 MW	8	24	10	8%	2	8%	24	10%	0%	10%	15%	100%	3	30
Steam Turbine [Oil] <100 MW	6	10	10	8%	3	8%	30	10%	0%	10%	75%	100%	5	34
Steam Turbine [Oil] <200 MW	6	16	10	8%	2	8%	27	10%	0%	10%	35%	100%	4	30
Steam Turbine [Oil] >200 MW	8	24	10	8%	2	8%	25	10%	0%	10%	15%	100%	3	30
Nuclear	163	164	0	1%	9	6%	24	0%	0%	0%	10%	20%	0	0
Wind	1	1	0	70%	1	0%	0	0%	0%	0%	100%	100%	0	0
Hydro	0	0	0	0%	0	0%	0	25%	0%	0%	50%	50%	0	0
PS	0	0	0	0%	0	0%	0	0%	0%	0%	0%	0%	0	0
Steam Turbine [Refuse]	6	10	0	8%	7	8%	14	10%	0%	0%	100%	100%	0	0
Geothermal Units	1	1	0	1%	0	3%	7	0%	0%	0%	100%	100%	0	0
Solar	1	1	0	80%	1	0%	0	0%	0%	0%	100%	100%	0	0

X. Emissions Rates and Prices

a. Current Trends Scenario

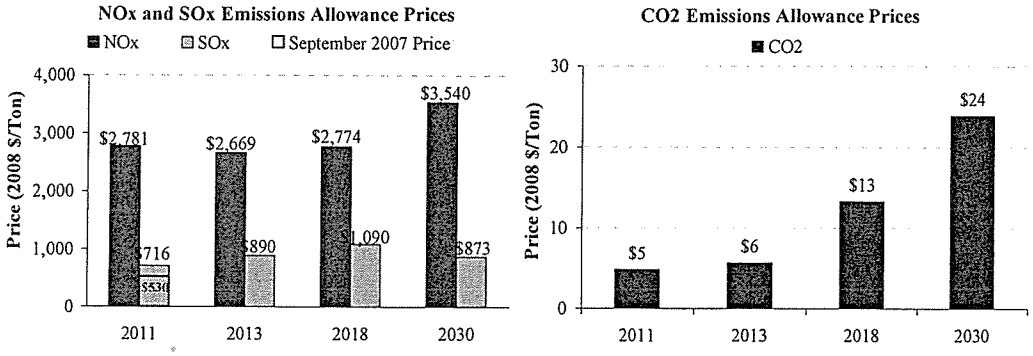
CO_2 emission allowance prices correspond to the Regional Greenhouse Gas Initiative (RGGI) through 2013 and federal legislation thereafter, as described in Appendix F. RGGI CO_2 allowance prices in 2011 and 2013 are based on the January, 2007 Maryland RGGI study (Maryland Study),[10] which projects CO_2 emission allowance prices for years 2010, 2015, 2020, and 2025. The 2011 and 2013 simulation prices are based on the Maryland Study projected 2010 prices, grown at the projected 2010-2015 annual growth rate.

CO_2 emissions prices in the study years 2018 and 2030 are based on the proposed 2007 Bingaman Bill Safety Valve.[11] This bill assumes a nominal safety valve price of $12 in 2012, escalating in real terms at 5% per year. For further discussion of assumptions related to this bill and other CO_2 reduction policies please see Appendix F.

NO_x and SO_x emissions allowance prices for all study years are based on the Energy Information Administration's (EIA) most recent reference case forecast.[12] Figure G.12 summarizes the NO_x, SO_x, and CO_2 allowance prices assumed in each study year.

[10] *Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative*, Maryland Department of the Environment, January 2007.
[11] *Low Carbon Economy Act of 2007*, Page 16.
[12] *2007 Annual Energy Outlook*, Energy Information Administration, Reference Case Files.

Figure G.12: Emissions Allowance Prices in Current Trends Scenario



Emission rates in 2011 and 2013 assume (1) unit-specific emissions rates for the "Sooty Six" plants based on EPA CEMS data,[13] (2) average NO_x and SO_x rates by fuel type for all other fossil fuel-burning plants greater than 25 MW, and (3) average CO_2 rates by fuel type for all other units subject to RGGI.[14] Some generating units in Connecticut must submit two SO_2 allowances for each ton emitted under Connecticut law. This is implemented by increasing SO_x VOM by the additional SO_x cost for all units in CT>25 MW to reflect the additional SO_2 cost. In 2018 and 2030, the list of CO_2-monitored units under federal legislation includes all fossil-fuel-burning units greater than 25 MW. Figures G.13 and G.14 show the assumed unit-specific NO_x, SO_x, and CO_2 emissions rates for the "Sooty Six" plants, and the generic emissions rates used for all other plants, respectively.

[13] Sooty Six units include Bridgeport Harbor 2 & 3, Devon 7 & 8 (retired), Middletown 2-4, New Haven Harbor, Norwalk Harbor 1 & 2, Middletown 2 & 3 and Montville 5 & 6. Emissions rates are averages of reported CEMS rates in 2006. Rates for Middletown 2 & 3 and Montville 5 have been set to the average Sooty Six levels for the unit types due to poor data quality. Unit-specific rates for Montville 6 are not captured in this analysis, so generic rates are applied.

[14] Average CO2 rates are calculated based on EPA carbon content coefficients. See http://www.epa.gov/climatechange/emissions/downloads/2007GHGFastFacts.pdf. Units subject to RGGI are based on a draft list published by RGGI at http://www.rggi.org/draftlists.htm; however, there is no definitive list of RGGI affected units. The original state budgets were based on a preliminary list, and the criteria for plant selection remain somewhat ambiguous. The criteria refer to original "nameplate" capacity ratings, which can be different than more recent capacity measures. It also applies to units that use more than 50% fossil fuel, which may vary over time.

Figure G.13: Assumed Emissions Rates for Sooty Six Units

Unit Name	Assumed Emissions Rate (Lbs/MMBtu)		
	CO2	SOx	NOx
BRIDGEPORT HARBOR 2	162	0.272	0.302
BRIDGEPORT HARBOR 3	205	0.181	0.136
DEVON 7*	N/A	N/A	N/A
DEVON 8*	N/A	N/A	N/A
MIDDLETOWN 2	162	0.276	0.171
MIDDLETOWN 3	162	0.276	0.171
MIDDLETOWN 4	162	0.275	0.149
MONTVILLE 5	162	0.276	0.171
MONTVILLE 6**	N/A	N/A	N/A
NEW HAVEN HARBOR	162	0.257	0.134
NORWALK HARBOR 1	162	0.292	0.142
NORWALK HARBOR 2	162	0.286	0.129
Average	167	0.266	0.167

*Devon 7 & 8 are retired.
**Generic rates are applied.

Figure G.14: Assumed Emissions Rates for All Other Units

Fuel Category	CO2 Emissions from Combustion *(Lbs CO2/MMBtu)*	NOx Emissions from Combustion *(Lbs NOx/MMBtu)*	SOx Emissions from Combustion *(Lbs SOx/MMBtu)*
NG	115.8	0.020	0.001
FO2	159.7	0.040	0.060
FO6	172.0	0.200	0.800
Coal	204.0	0.300	1.200

b. Strict Climate Scenario

The Strict Climate scenario assumes strict Federal legislation on CO_2 emissions to be in effect by the 2013 study year, so 2011 monitored units and emissions prices are identical to the Current Trends scenario. In 2013, the CO_2-monitored units under Federal legislation includes all fossil-fuel-burning (and refuse-burning) units greater than 25 MW, as in Current Trends 2018 and 2030 study years. Emissions rates are the same as the Current Trends scenario during the period in which Federal legislation is assumed to be in effect.

CO_2 emissions allowance prices under Strict Climate Federal legislation (study years 2013, 2018, and 2030) are based on the EIA assessment of S.280, the Lieberman Climate Stewardship and Innovation Act of 2007 (EIA S.280). The EIA S.280 CO_2 prices are doubled to account for offset sensitivity.[15]

c. High Fuel/Growth Scenario

The High Fuel/Growth scenario assumes all emissions rates, and 2011 and 2013 emissions allowance prices are unchanged from the Current Trends scenario. 2018 & 2030 CO_2 emission allowance prices are assumed to be 30% higher than in the Reference Case. NO_x and SO_x emissions allowance prices are unchanged from the Current Trends scenario.

d. Low Stress Scenario

All emissions rates and prices are unchanged from Current Trends scenario.

XI. Fuel Prices

a. Natural Gas

2011 Henry Hub natural gas prices are from NYMEX Henry Hub Futures as of 9/27/2007,[16] with prices available October 2007 through December 2012. 2013, 2018, and 2030 Henry Hub natural gas prices are derived using the previous year's average price, adjusted with a monthly multiplier to reflect seasonal variation, then grown using the annual EIA growth rate.[17] Monthly multipliers are calculated by using the NYMEX 2010 monthly/annual average price, removing the trend to leave only a seasonal pattern. Figure G.15 shows assumed monthly Henry Hub natural gas prices through 2030.

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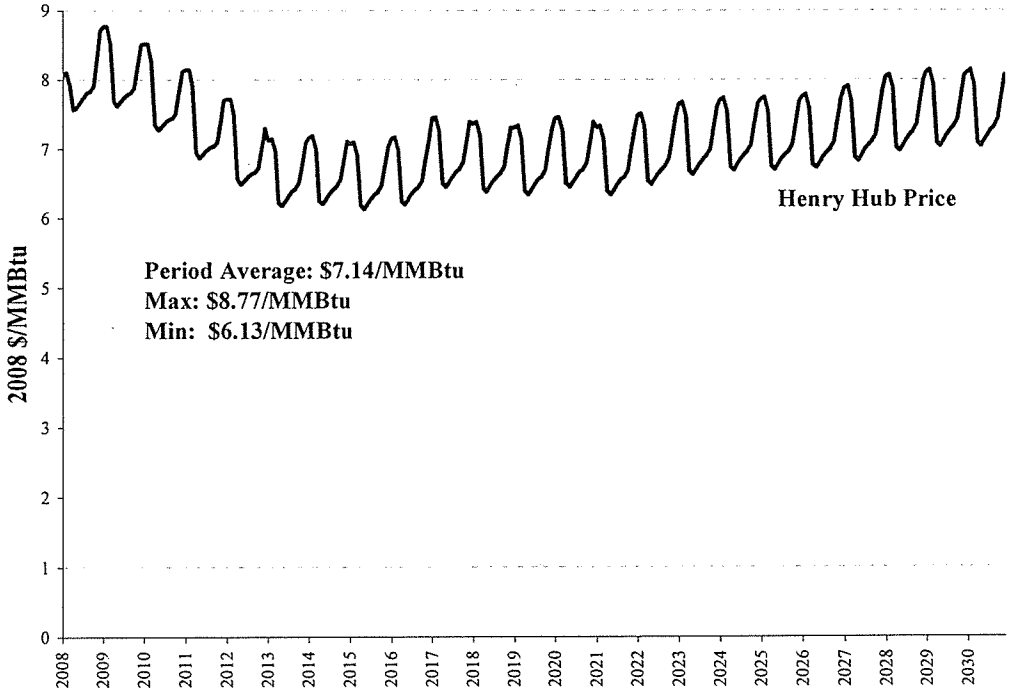
[15] The EIA analysis found that CO_2 prices were very sensitive to the amount of offsets allowed, and that under the same bill but without any offsets, the price would approximately triple.

[16] NYMEX futures prices as of September 27th, 2007: http://www.nymex.com/media/092707.pdf.

[17] *2007 Annual Energy Outlook*, Energy Information Administration, Table 11: Energy prices by Sector and Source (New England).

Figure G.15: Monthly Henry Hub Natural Gas Prices through 2030 in the Current Trends Scenario

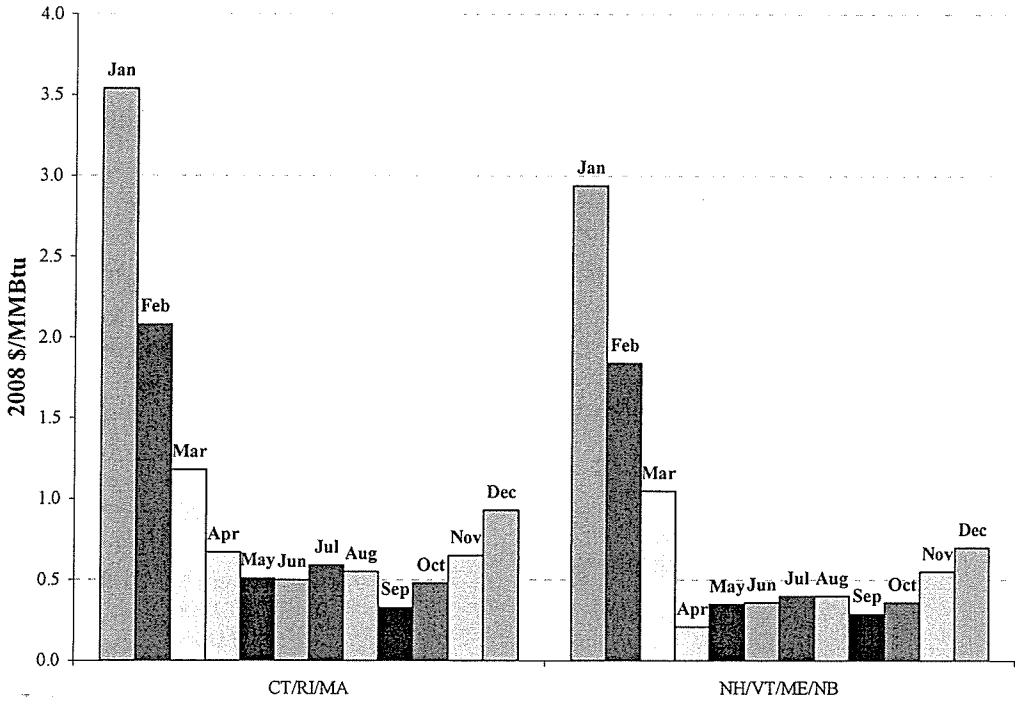


Future basis differentials from Henry Hub are based on historical average monthly basis differentials from 2003, 2004, and 2006.[18] Algonquin prices are used for Southern New England (CT, RI, MA), and Dracut prices (price of Canadian gas flowing south) are used for Northern New England (NH, VT, ME).[19] The average Algonquin winter differential is ~$1.70/MMBtu; summer is ~$.50/MMBtu; and the Algonquin annual average is $1.00/MMBtu, with Dracut at about 20 cents below Algonquin. Figure G.16 shows the assumed natural gas basis differentials used in all scenarios and study years.

[18] 2005 is excluded due to an unusually cold October.

[19] Monthly averages of Spot Prices for Henry Hub, Algonquin City gate and Dracut are from Platts *Gas Daily*. See www.platts.com.

Figure G.16: Assumed Natural Gas Basis Differentials in All Scenarios and Study Years



b. Distillate and Residual Fuel Oil

2011 Residual Fuel Oil (FO6) prices are based on NYMEX Crude Oil futures as of 9/27/2007, with prices available from October 2007 through December 2012. After 2012, FO6 prices are based on EIA daily historic (June 2, 1986-Sep 27, 2007) Crude Oil and Residual Fuel Oil spot prices.[20] A relationship between the historic Crude Oil prices and FO6 prices was determined using a simple linear regression, and FO6 prices are then predicted through 2030 based on this relationship. 2013, 2018, and 2030 FO6 prices use these predicted prices, grown at the annual EIA predicted growth rate.[21]

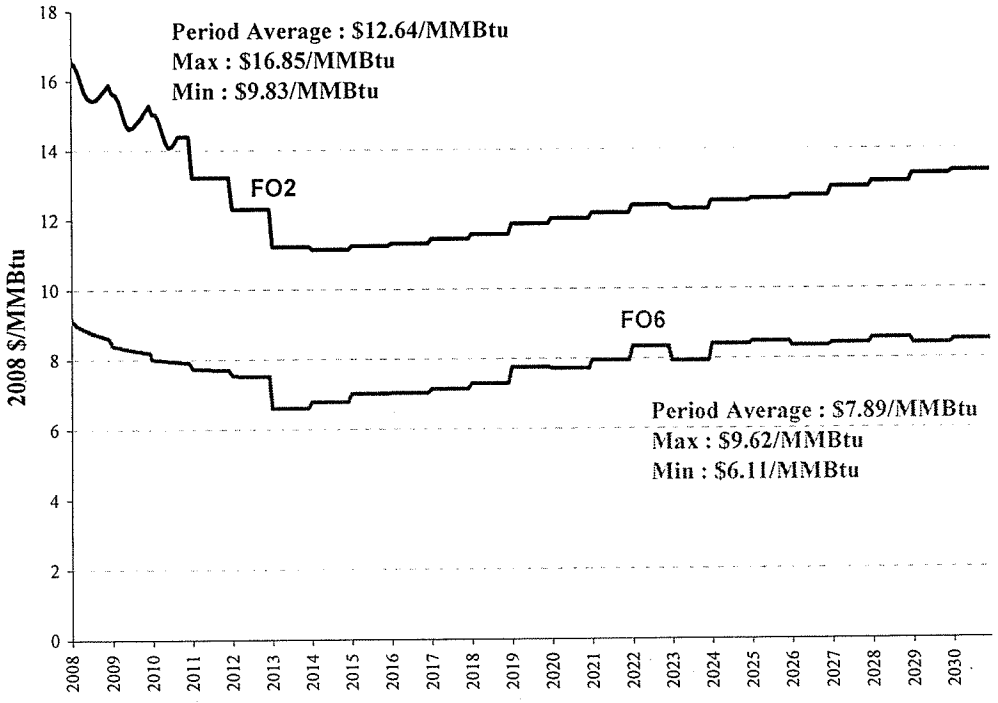
Distillate Fuel Oil (FO2) prices for all years are based on NYMEX Heating Oil futures as of 9/27/2007, with prices available from October 2007 through September 2010. All prices are then

[20] EIA: Petroleum Navigator: Spot Prices: Downloaded from the EIA Website: http://tonto.eia.doe.gov/dnav/pet/xls/pet_pri_spt_s1_d.xls.

[21] *2007 Annual Energy Outlook*, Energy Information Administration, Table 11: Energy prices by Sector and Source (New England).

grown at the annual EIA predicted growth rate.[22] Figure G.17 shows the assumed FO6 and FO2 prices through 2030 in the Current Trends Scenario.

Figure G.17: 2008-2030 Assumed FO2 and FO6 Prices in the Current Trends Scenario



c. Coal

2011 and 2013 delivered coal prices are unit-specific and are compiled by CES based on historic values. 2018 and 2030 prices for coal and "other" fuel use the CES-estimated 2015 nominal values. Figure G.18 summarizes delivered coal prices by unit for each of the study years.

[22] *2007 Annual Energy Outlook*, Energy Information Administration, Table 11: Energy prices by Sector and Source (New England).

Figure G.18: Assumed Delivered Coal Prices in All Scenarios and Study Years

Unit Name	Zone	State	Summer Capacity (MW)	Average Price (2008 $/MMBtu)			
				2011	2013	2018	2030
AES THAMES	Rest of CT Zone	CT	181	$3.13	$2.99	$2.87	$2.87
BRAYTON PT 1	South Eastern MA Zone	MA	243	$3.01	$2.88	$2.76	$2.76
BRAYTON PT 2	South Eastern MA Zone	MA	222	$3.01	$2.88	$2.76	$2.76
BRAYTON PT 3	South Eastern MA Zone	MA	612	$3.01	$2.88	$2.76	$2.76
BRIDGEPORT HARBOR 3	South Western CT Zone	CT	372	$3.13	$2.99	$2.87	$2.87
MEAD	Maine Zone	ME	75	$3.01	$2.88	$2.76	$2.76
MERRIMACK 1	New Hampshire Zone	NH	112.5	$2.82	$2.70	$2.59	$2.59
MERRIMACK 2	New Hampshire Zone	NH	320	$2.82	$2.70	$2.59	$2.59
MT TOM	West Central MA Zone	MA	145	$3.09	$2.96	$2.84	$2.84
SALEM HARBOR 1	NE MA Boston Zone	MA	82	$3.27	$3.13	$3.00	$3.00
SALEM HARBOR 2	NE MA Boston Zone	MA	80	$3.27	$3.13	$3.00	$3.00
SALEM HARBOR 3	NE MA Boston Zone	MA	149	$3.27	$3.13	$3.00	$3.00
SCHILLER 4	New Hampshire Zone	NH	47.5	$2.82	$2.70	$2.59	$2.59
SCHILLER 5*	New Hampshire Zone	NH	47	$2.82	$2.70	$2.59	$2.59
SCHILLER 6	New Hampshire Zone	NH	47	$2.82	$2.70	$2.59	$2.59
SOMERSET	Maine Zone	ME	10	$3.01	$2.88	$2.76	$2.76
SOMERSET 6	South Eastern MA Zone	MA	105	$3.11	$2.97	$2.85	$2.85
	Total		**2850**				

*Schiller 5 has been converted to wood, which is not captured in the model.

XII. DEMAND-SIDE MANAGEMENT (DSM) [23]

All Connecticut demand response programs have been forecasted through 2018 by the Companies.[24] The Companies have provided calendar-year estimates of DSM programs by company, including 2007-2018 energy and peak reduction values for energy efficiency (EE) and 2007-2018 peak reduction values for demand response (DR). After 2018, DSM-induced load reductions are assumed to remain constant as a percentage of load. Data are adjusted to mid-year values using a 33% half-year factor.[25] Thc data are at-meter estimates so all DSM values are grossed up by 8% for transmission and distribution losses before being deducted from the energy needed to meet load. For capacity planning purposes, load reductions that are counted as supply

[23] Here, "demand-side management" refers to both energy conservation and demand response. "Energy efficiency" in this appendix refers only to the energy conservation element of DSM.

[24] See "CT DSM Sum_Ver 7_CLP UI Rev-with Stata input database_ 31 Oct 07_HEAVY and BASE CASE.xls." The Client provided an updated version as of November 1, 2007 which could not be implemented due to schedule requirements.

[25] Mid-year estimates are calculated as 2/3*(preceding year EOY estimates) + 1/3*(current year's EOY estimates).

are grossed up by an additional 16.6% to account for the associated reduction in required reserves.[26]

The companies have forecasted a "Reference" level of DSM which is used in the Conventional, Nuclear, and Coal resource solutions, and a "Heavy" level of DSM which is used in the DSM-Focus resource solution. Since there are detailed data on DSM plans only for Connecticut, Base DSM programs are extrapolated to the rest of New England (RONE) assuming half as much growth in DSM per megawatt of total load. In the DSM-Focus resource solution RONE is assumed to continue with Base DSM, while Connecticut implements Heavy DSM. Once the Connecticut and RONE DSM values are determined, the data are split into DAYZER subzones by share of summer peak reference case forecast gross load.

DSM in the Current trends scenario is assumed to be achieve the load reductions shown in Tables 2.2 and 2.3 and described in Appendix D, and this effectiveness is reduced in other scenarios in which elevated prices induce a "natural" reduction in load, leaving a smaller incremental effect of DSM.

XIII. Gross and Net Load[27]

All DSM is implemented in DAYZER via load adjustments from the "gross" load forecast, producing a "net" load. Gross and net load implementation is described below for each scenario. The methodology of determining the gross and net load levels is described in more detail in Appendix B.

a. Current Trends Scenario

Load in the Current Trends scenario is based on the ISO-NE weather-normalized 2008-2016 hourly subzonal forecast shown in the *CELT* report (*CELT* Load Forecast),[28] extrapolated to the 2018 and 2030 study years. The 2016 *CELT* Load Forecast is extrapolated through 2030 by using the long-term 2015-2016 summer and winter reference case peak load growth rates. Weekdays in 2017-2030 are aligned with 2016 weekdays, and the long-term seasonal growth

[26] Also, the data do not include RGGI savings.
[27] Net load refers to load net of DSM program effects.
[28] http://www.iso-ne.com/trans/*CELT*/fsct_detail/index.html

rates are applied to the 2016 load forecast. Demand-side Management (DSM) load reductions are not included in the *CELT* Load Forecast, as indicated in the ISO's Representative ICR Calculation.[29] However, Companies' estimates of future DSM are ultimately reflected in the load inputs to the model, the implementation of which is explained at the end of this section.

The *CELT* Load Forecast subzones BOSTON/CMASS, WMASS, and NEMASS do not correspond directly with DAYZER subzones, so the Massachusetts load data are split into redefined DAYZER subzones. DAYZER NEMASS/BOSTON and WCMASS zones are derived from the *CELT* Load Forecast subzones by using the *CELT* Load Forecast reported demand shares by zone. The *CELT* Load Forecast reports that WCMASS is 13.4% of ISO-NE in the summer and 13.7% of ISO-NE in the winter, and NEMASS/BOSTON is 19.4% of ISO-NE in the summer and 19.2% of ISO-NE in the winter. Hence, for summer months (April through October in the model), the total WCMASS/NEMASS/BOSTON subzone share of total ISO is 32.8%. WCMASS is 40.854% of this share, and NEMASS/BOSTON is the remaining 59.146% of this share. For winter months, the total WCMASS/NEMASS/BOSTON subzone share of total ISO is 32.9%. WCMASS is 41.641% of this share, and NEMASS/BOSTON is the remaining 58.359% of this share, and the load is divided accordingly. Figure G.19 displays the DAYZER subzones, and overlapping ISO subzones.

Figure G.19: DAYZER and ISO Subzones

DAYZER Subzone	State	ISO Subzone	
Rest of CT Zone	CT	CT	
Norwalk- Stamford Zone	CT	NOR	
South Western CT Zone	CT	SWCT	
NE MA Boston Zone	MA	BOSTON/CMA-NEMA	*
South Eastern MA Zone	MA	SEMA	
West Central MA Zone	MA	W-MA/CMA-NEMA	*
Maine Zone	ME	ME/S-ME/BHE	
New Hampshire Zone	NH	NH	
Rhode Island Zone	RI	RI	
Vermont Zone	VT	VT	

*Load in these ISO subzones is split to correspond with the DAYZER subzones.

[29] Agustin, Maria, "Representative Installed Capacity Requirements for RSP07," PSPC Meeting No. 233, Agenda Item 5.0, August 16, 2007, slide 14.

In its forecast, the ISO-NE projects a long-term declining growth rate, which is consistent with the CT DPUC's understanding of long-term growth rates.[30] For years beyond 2016 we extrapolate 2015-2016 growth rates, which are approximately only one percent. Figure G.20 shows 2015 and 2016 peak load by ISO-NE subzone, long-term peak growth rates, and subzone shares of total ISO non-coincident peak load.

Figure G.20: Summary of ISO-NE Long-Term Peak Load Forecast and Load Growth Rates

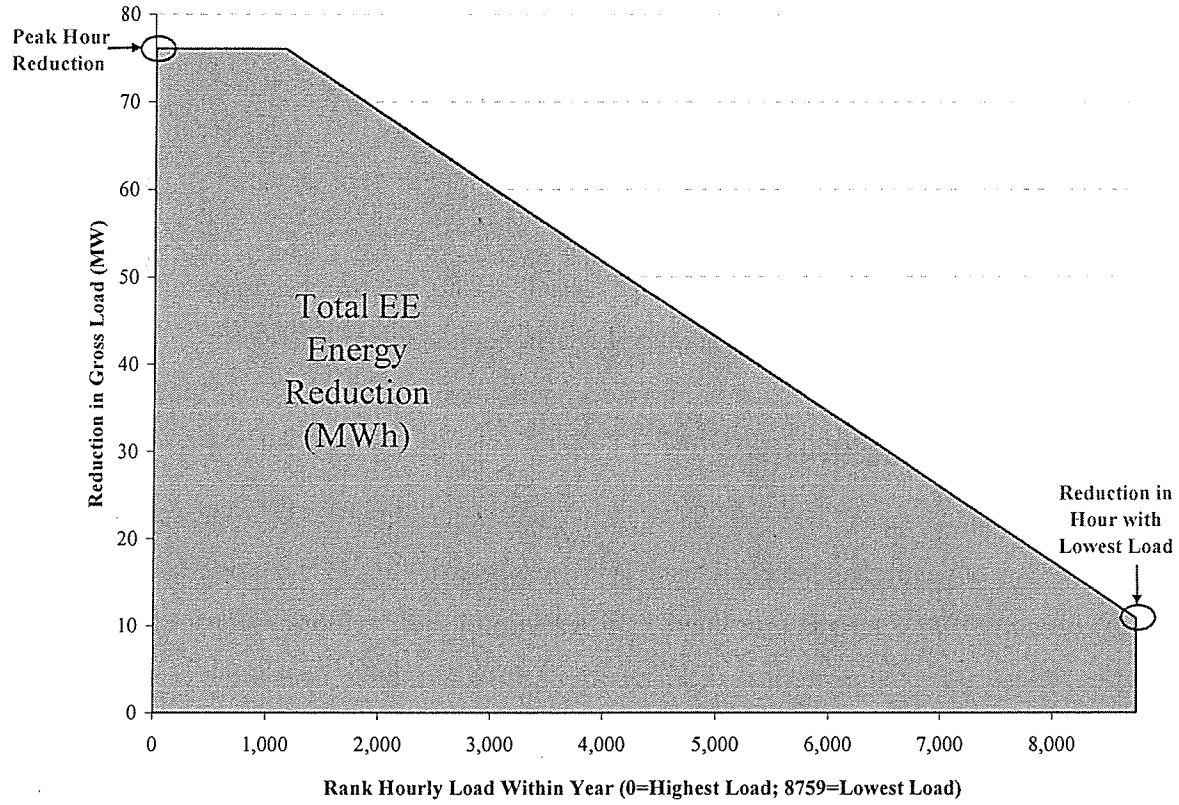
	2015 Peak Load		2016 Peak Load		CAGR Growth		2015-2016 Growth		2016 Subzone Shares	
ISO-NE Subzone	Summer Peak (50/50) (MW)	Winter Peak (50/50) (MW)	Summer Peak (50/50) (MW)	Winter Peak (50/50) (MW)	Summer Peak (50/50)	Winter Peak (50/50)	Summer Peak (50/50)	Winter Peak (50/50)	Summer Peak (50/50)	Winter Peak (50/50)
BHE	347	331	350	335	1.6%	1.4%	0.9%	1.2%	1.1%	1.3%
BOSTON	6,190	4,912	6,254	4,966	1.5%	1.1%	1.0%	1.1%	19.6%	19.4%
CMANEMA	2,075	1,641	2,104	1,658	1.3%	1.0%	1.4%	1.0%	6.6%	6.5%
CT	4,092	3,255	4,139	3,284	1.7%	1.1%	1.1%	0.9%	13.0%	12.8%
ME	1,241	1,217	1,259	1,232	2.0%	1.4%	1.5%	1.2%	3.9%	4.8%
NH	2,477	1,968	2,523	2,001	2.7%	1.5%	1.9%	1.7%	7.9%	7.8%
NOR	1,455	1,124	1,471	1,134	1.5%	1.1%	1.1%	0.9%	4.6%	4.4%
RI	2,917	2,063	2,951	2,082	1.8%	1.0%	1.2%	0.9%	9.3%	8.1%
SEMA	3,336	2,595	3,377	2,621	1.6%	1.1%	1.2%	1.0%	10.6%	10.2%
SME	768	660	779	667	1.9%	1.2%	1.4%	1.1%	2.4%	2.6%
SWCT	2,742	2,237	2,765	2,258	1.6%	1.5%	0.8%	0.9%	8.7%	8.8%
VT	1,441	1,342	1,457	1,361	1.8%	1.2%	1.1%	1.4%	4.6%	5.3%
WMA	2,423	2,005	2,452	2,023	1.8%	0.9%	1.2%	0.9%	7.7%	7.9%
Total									100.0%	100.0%

EE is implemented by (1) reducing the peak load by the EE peak hour reduction (2) reducing gross load such that hours are not reordered in the load duration curve and (3) making total reductions consistent with the required EE energy reduction. This is achieved by first reducing the peak load by the peak hour reduction, reducing the last hour on the load duration curve by 1 MW, interpolating reductions between these two points on the load duration curve, then iteratively reducing each hour by .01 MW increments (subject to the max peak hour reduction) until the required EE energy reduction is met. Figure G.21 illustrates Reference DSM EE

[30] December 5, 2006 Addendum Updated Load Forecast; Connecticut Department of Public Utility Contro Request for Proposals to Reduce Impact of FMCCs; Docket No. 05-07-14PH02. See http://www.connecticut2006rfp.com/rfp_docs.php.

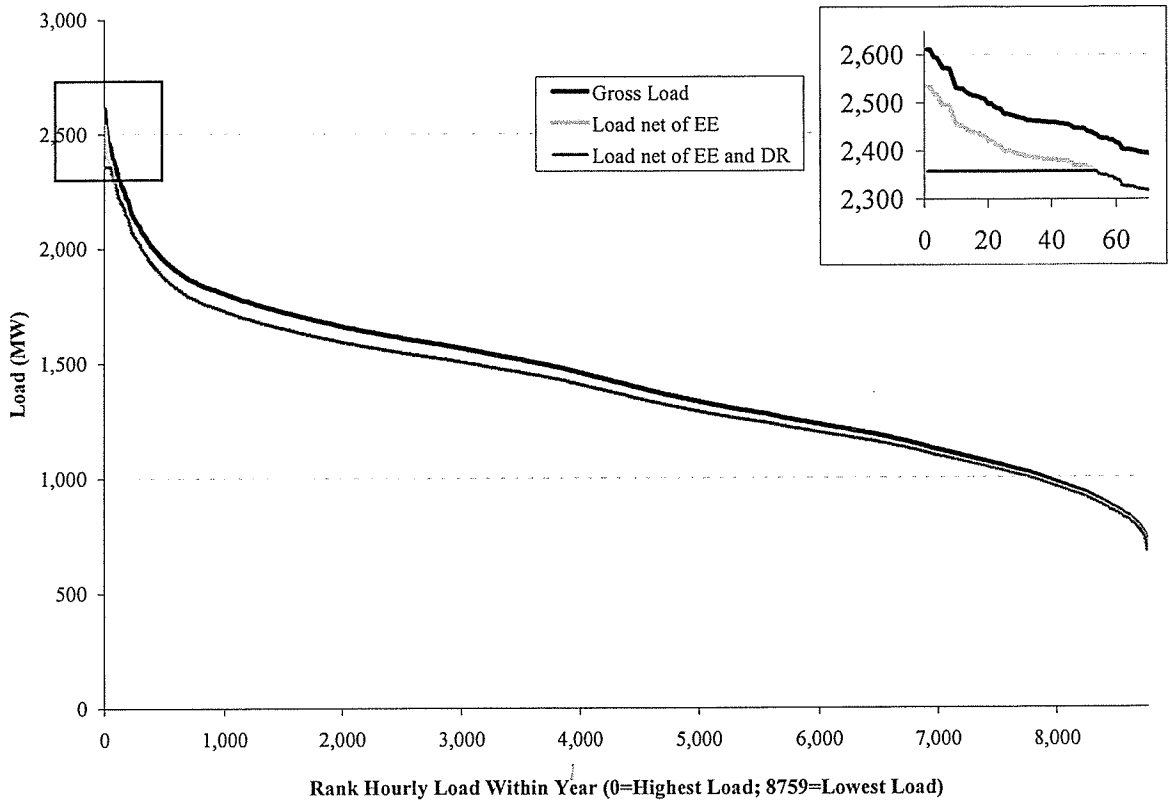
reductions on 2011 gross load for the SW-CT subzone in the Current Trends Scenario. This subzone and level of DSM is used as an example to demonstrate load adjustment methodology in all scenarios, as shown in Figures G.21 through G.28 described in this section. DR is always implemented by "shaving" the peak load after EE reductions have been implemented: the peak hour load minus the DR peak hour reduction becomes the max load for the year.[31] Figure G.22 shows the final net load after Reference DSM EE and DR reductions in the Current Trends Scenario.

Figure G.21: Methodology for Implementing Peak and Energy Adjustments due to Reference DSM in the Current Trends Scenario: 2011 SW-CT Example



[31] This is a simplification that does not account for the shifting of load to other hours.

Figure G.22: Net Load with Reference DSM in the Current Trends Scenario: 2011 SW-CT Example

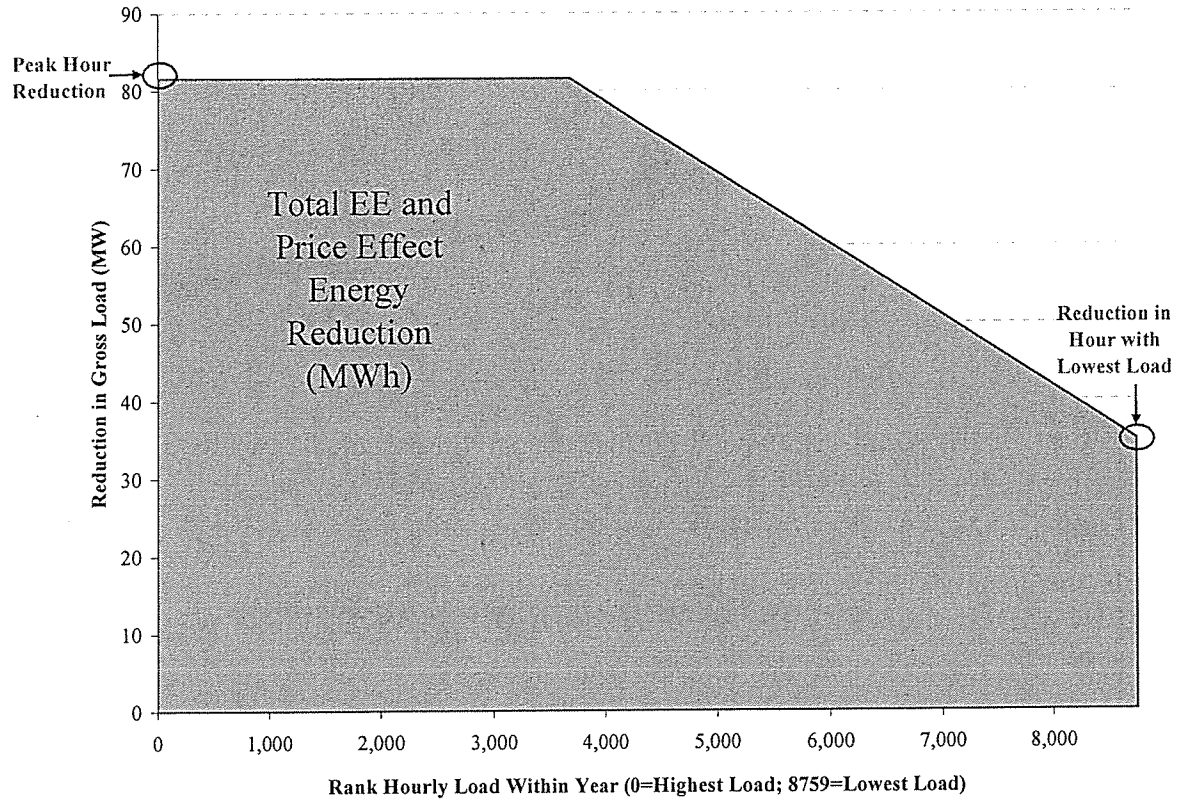


b. Strict Climate Scenario

The Strict Climate scenario assumes the same gross load (without DSM effects) as the *CELT* Load Forecast, but with load reductions due to response to higher fuel prices, and lowered effectiveness of DSM efforts due to these load reductions. The full price impact is realized by 2018, and consists of a short-term peak impact of -1.39%, phased in over three years from 2009 through 2011, and an additional long-term impact of -1.04%, phased in over the next seven years from 2012 through 2018. After 2018 load is assumed to continue at a 1% growth rate. Load adjustments to the *CELT* Load Forecast are applied simultaneously with DSM adjustments. Combined price effect and EE peak and energy reductions are implemented as in the Current Trends Scenario, as are DR reductions. Figure G.23 illustrates the 2011 SW-CT combined EE

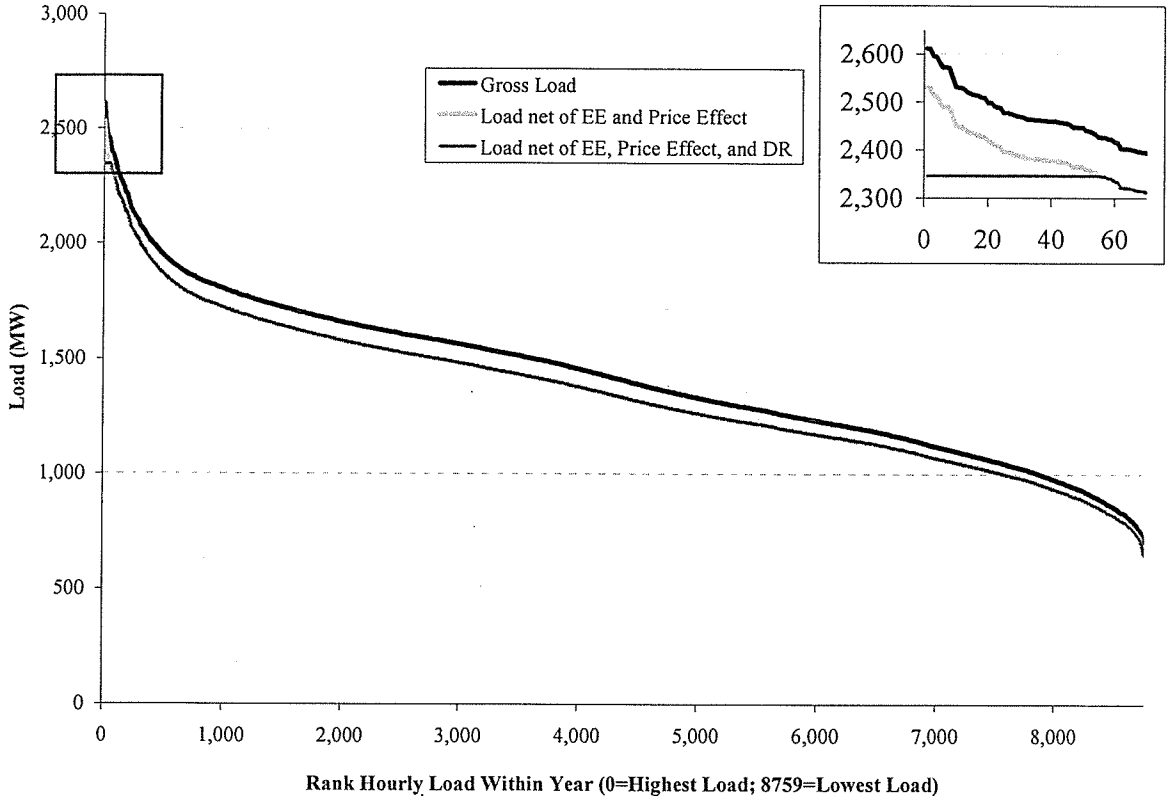
and fuel price effect peak and energy reductions, and Figure G.24 shows the net load after all adjustments, including DR.[32]

Figure G.23: Methodology for Implementing Peak and Energy Adjustments due to Reference DSM and Fuel Price Effects in the Strict Climate Scenario: 2011 SW-CT Example



[32] DR implementation in all scenarios is the same: once gross load is determined and fuel price effects and EE peak and energy reductions are applied, the DR peak shaving is implemented.

Figure G.24: Net Load with Fuel Price Effect and Reference DSM in the Strict Climate Scenario: 2011 SW-CT Example



c. High Fuel/Growth Scenario

Energy in the High Fuel/Growth scenario is assumed to grow at a rate 0.8% higher than in the Current Trends scenario through 2018 to reflect a high growth environment, then at a long-term growth rate of approximately 1% through 2030. High fuel prices are assumed to induce a price impact on this high growth load, consisting of a short-term impact of -3.68% phased-in over 3 years, plus an additional -2.76% long-run reduction phased-in over the next 7 years. Changes from the *CELT* Load Forecast in the underlying gross load, fuel price effects, and EE peak and energy reductions are implemented simultaneously.

In this scenario, the combined average energy reduction is typically greater than the peak reduction, and in these cases the hourly reduction in absolute terms is assumed to ramp up on the load duration curve to meet the required total energy reduction. This implies a relative

insensitivity during the highest load hours to load reduction forces, and the slope of the ramp in each subzone has been made proportional to that subzone's share of total load to reflect greater peak insensitivity in smaller subzones. Figure G.25 illustrates the 2011 SW-CT combined change in gross load, EE, and fuel price effect peak and energy reductions. If the combined average energy reduction is smaller than the combined average peak reduction then adjustments are made following the EE adjustment methodology in the Current Trends Scenario. Figure G.26 shows the net load after all 2011 High Fuel/Growth Scenario adjustments in SW-CT, including DR.

Figure G.25: Methodology for Implementing Peak and Energy Adjustments due to Differences in Gross Load, Reference DSM, and Fuel Price Effects in the High Fuel/Growth Scenario: 2011 SW-CT Example

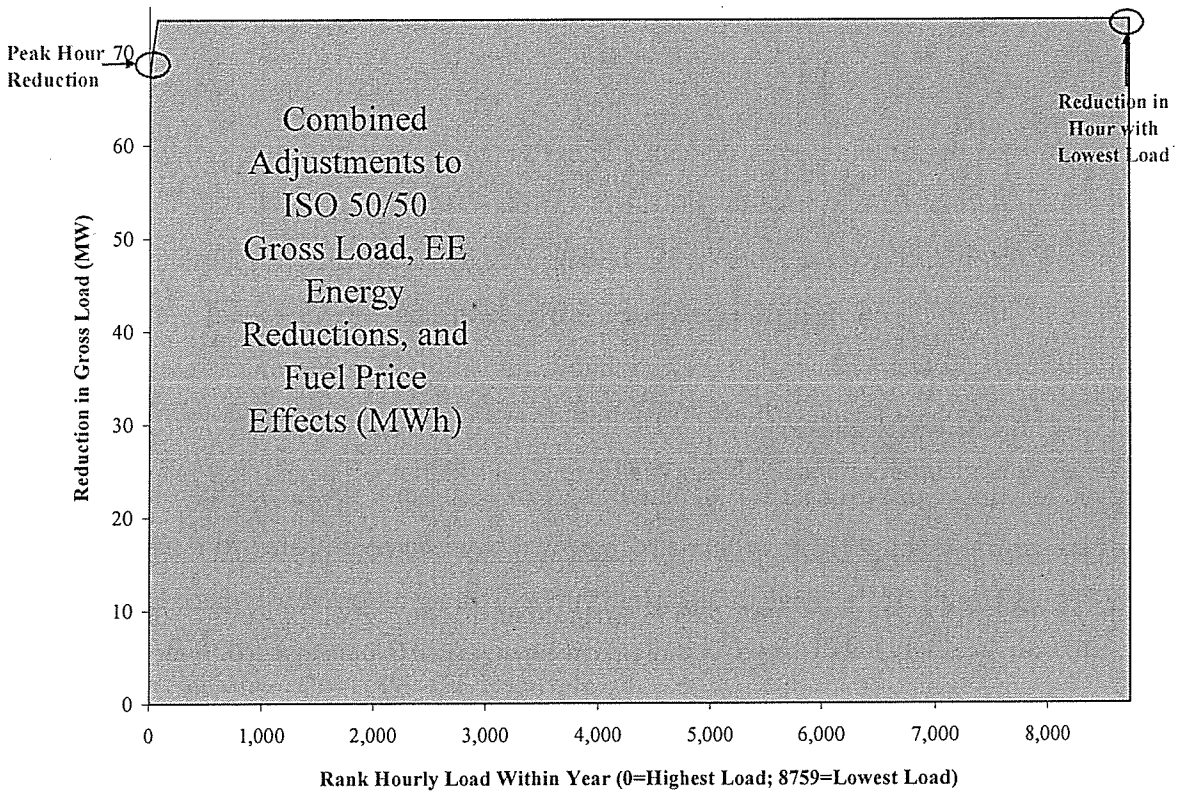
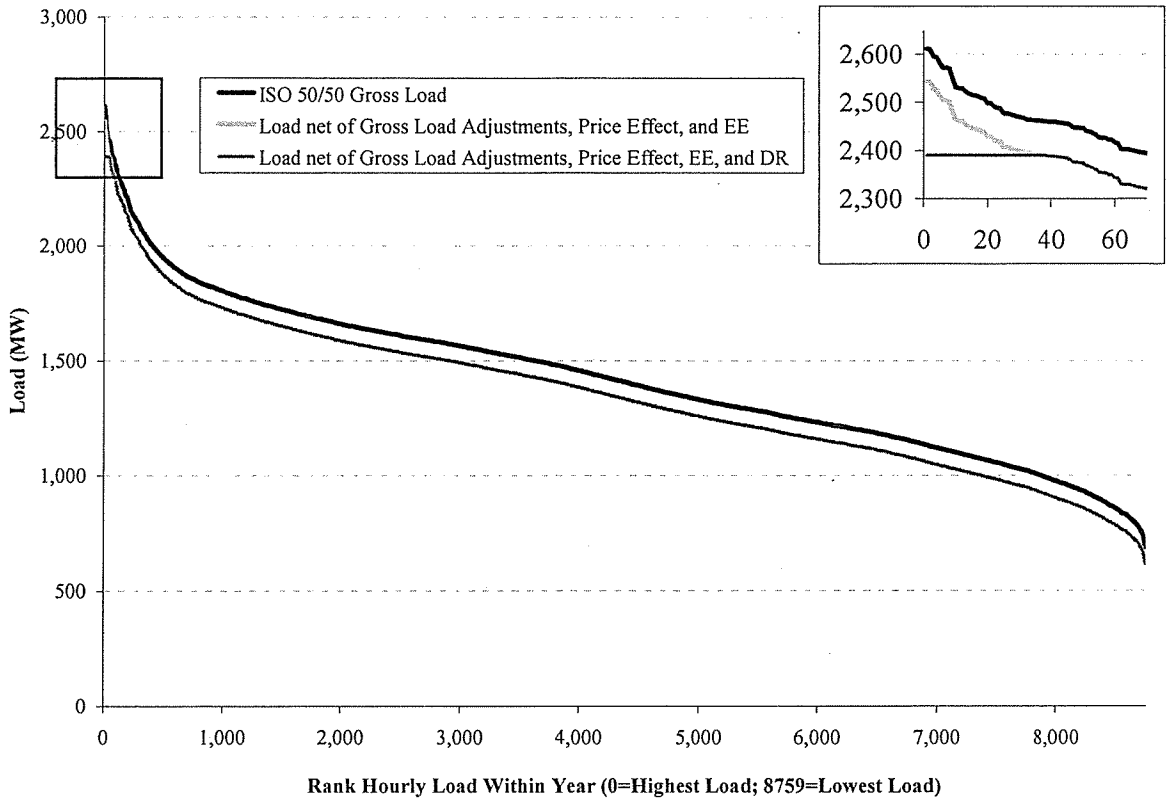


Figure G.26: Net Load with Gross Load Adjustments, Fuel Price Effect, and Reference DSM in High Fuel/Growth Scenario: 2011 SW-CT Example



d. Low Stress Scenario

Energy in the Low Stress scenario is assumed to grow at a rate 0.4% higher than in the Current Trends scenario through 2018 to reflect a high growth environment, then at a long-term growth rate of approximately 1% through 2030. High fuel prices are assumed to induce a price impact on this low stress load, consisting of a short-term impact of 2.04% phased-in over 3 years, plus an additional 1.53% long-run reduction phased-in over the next 7 years.

Combined gross load adjustments, fuel price effects, and EE peak and energy reductions typically lead to large positive peak reductions, coupled with very small energy reductions (sometimes *negative* – an energy *increase*). In some cases, there is an increase in both peak and energy. These results indicate some energy shifting in this scenario, and the combined adjustments to the *CELT* Load Forecast gross load (excluding DR) are implemented assuming

that the relative energy reductions in the highest load hours are shifted to off-peak hours. So, some off-peak hours always show a net energy increase, regardless of the sign of total energy adjustments. Figure G.27 shows the 2011 SW-CT combined change in gross load, EE, and fuel price effect peak and energy reductions. Figure G.28 shows the net load after all 2011 Low Stress Scenario adjustments in SW-CT, including DR.

Figure G.27: Methodology for Implementing Peak and Energy Adjustments due to Differences in Gross Load, Reference DSM, and Fuel Price Effects in the Low Stress Scenario: 2011 SW-CT Example

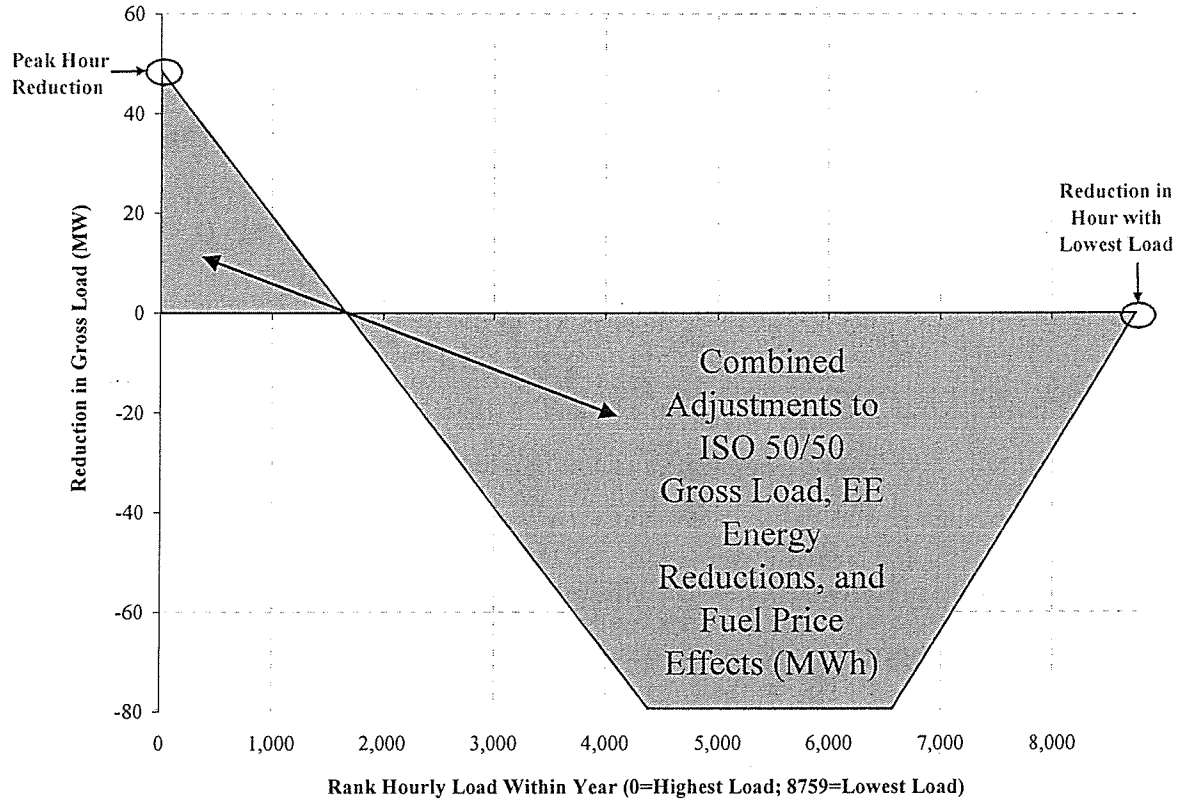
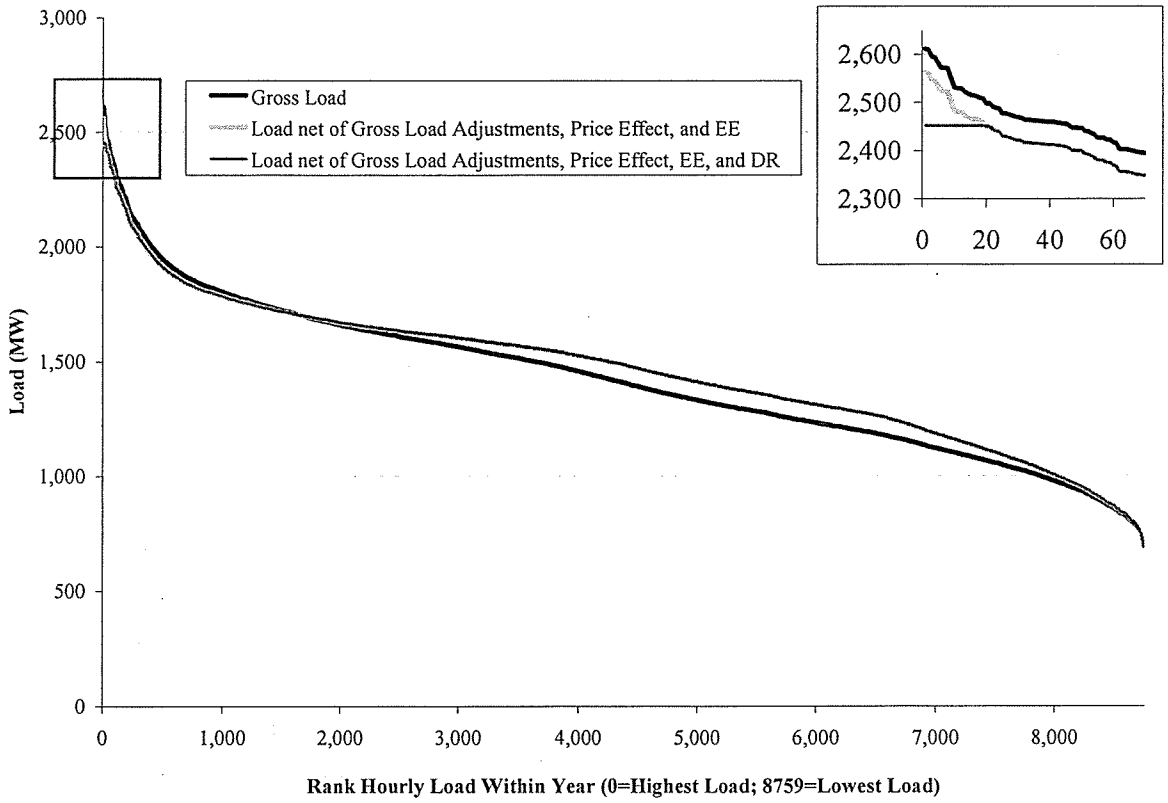


Figure G.28: 2011 SW-CT Net Load with Gross Load Adjustments, Fuel Price Effect, and Reference DSM in Low Stress Scenario

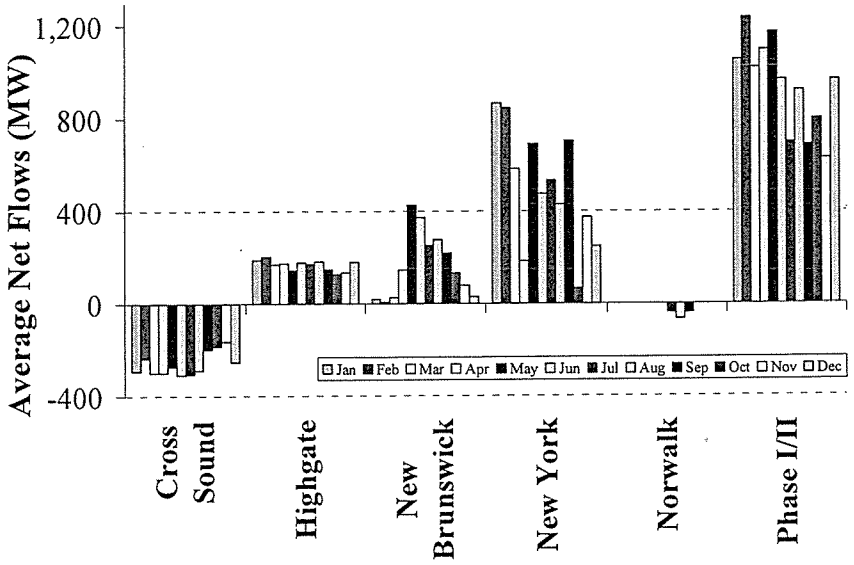


XIV. EXTERNAL FLOWS: ISO-NE NET IMPORTS

DAYZER models ISO-NE independently, and flows in and out of the ISO-NE system are non-dynamic. 2011 hourly net imports are forecasted by CES by extrapolating the most recent[33] ISO-NE actual import/export data by weekday/weekend and month. 2013, 2018, and 2030 net imports use 2011 values, realigned by weekday. Figure G.30 summarizes the assumed ISO import/export schedule for all cases.

[33] As of September, 2007. Import/export data are downloaded from the ISO-NE website.

Figure G.30: Average Net Imports to ISO-NE System



XV. Reserve Requirements

2011 hourly spin and AGC reserve requirements are forecasted by CES by extrapolating historical values by weekday/weekend and season. 2013, 2018, and 2030 net imports use 2011 values, realigned by weekday. Hourly spin requirements range from 1267-1320 MW, and hourly AGC reserve requirements (added to the spin requirement in the model) range from 100-280 MW. Quickstart requirements not modeled.

XVI. Transmission

a. Topology

The transmission system representation is based on the load flow used for the ISO-NE November 2006 FTR auction, which we upgraded to include Phase II of the Southwest Connecticut Reliability Project (345-kV Middletown-Norwalk Project) and the 345 kV Ludlow-Barbour Hill Project by the 2011 study year, then further upgraded to include major New England East/West Solution (NEEWS) elements by the 2013 study year. Full project details are extensive so, for simplicity, only major elements expected to have a significant impact on the simulation results

(all 345kV and 115kV elements) of each project are implemented. The major additions to the November 2006 load flow to represent these transmission enhancements in the 2011 and 2013 study years are listed in Figures G.31 and G.32, respectively.

Figure G.31: Additions to 2006 Load Flow to Represent the 345-kV Middletown-Norwalk Project and the 345 kV Ludlow-Barbour Hill Project by the 2011 Study Year

Element Name	Element Type	Summer Rating A	Summer Rating B
BESECK 345	Substation		
HADAMNK 345 - BESECK 345	Line	1488	1793
HADDAM 345 - BESECK 345	Line	1488	1912
SOTHNGTN 345 - BESECK 345	Line	1488	1912
E_DEVON 345	Substation		
BESECK 345 - E_DEVON 345	Line	2038	2634
DEVON - E_DEVON	Transformer	707	797
SINGER 345	Substation		
E_DEVON 345 - SINGER 345 CKT1	Line	600	1128
E_DEVON 345 - SINGER 345 CKT2	Line	600	1128
BRIDGEPT 115 - SINGER 345	Transformer	435	440
SINGER 345 - NORWLK 345 CKT1	Line	600	1128
SINGER 345 - NORWLK 345 CKT2	Line	600	1128
BARBOURH 345	Substation		
BARBOURH 115 - BARBOURH 345	Transformer	747	795
BARBOURH 345 - LUDLOW 345	Line	1240	1604
BARBOURH 345 - MEEK_J 345	Line	1240	1604

Figure G.32: Additions to 2006 Load Flow to Represent NEEWS by the 2013 Study Year

Element Name	Element Type	Summer Rating A	Summer Rating B
Manchester 345 - Card 345 CKT 2	Line	1488	1912
Card 345 - Millstone 345 CKT 2	Line	1255	1446
Manchester 115 - East Hartford 115 CKT 2	Line	250	371
SW Hartford 115 - NW Hartford 115	Line	250	371
S Meadow 115 - SW Hartford 115 CKT 2	Line	171	307
Frost Bridge 345 - N Bloomfield 345	Line	2035	2635
Frost Bridge 115 - Frost Bridge 345	Transformer	632	780
Lake Road 345 - West Farnum 345	Line	2035	2635
Card 345 - Lake Road 345 CKT 2	Line	2035	2635
W. Farnum 345 - Millbury 345	Line	2172	2696
W. Farnum 345 - Kent Co. 345 CKT2	Line	1545	1908
Kent Co. 345 - Kent Co. 115 (2)	Transformer	487	580
Kent Co. 345 - Kent Co. 115 (3)	Transformer	487	580
Berry 345	Substation		
Berry 345 - Bellingham 345	Line	1007	1157
Berry 345 - Brayton Point 345	Line	1007	1157
Berry 115	Substation		
Berry 115 - Berry 345	Transformer	515	580
Berry 115 - S. Wrenthem 115 CKT1	Line	287	330
Berry 115 - S. Wrenthem 115 CKT2	Line	287	330
Berry 115 - N. Attleboro 115 CKT1	Line	287	330
Berry 115 - N. Attleboro 115 CKT2	Line	287	330
Agawam 345	Substation		
Agawam 345 - Agawam 115 (1)	Transformer	632	780
Agawam 345 - Agawam 115 (2)	Transformer	632	780
Ludlow 345 - Agawam 345	Line	2035	2635
Agawam 345 - N. Bloomfield 345	Line	1200	2400
Stony Brook 115 - 5 Corners 115	Line	678	878
Stony Brook 115 - 5 Corners 115	Line	678	878
N. Bloomfield 115- N. Bloomfield 345 (2)	Transformer	632	780
Southwick 115 - S. Agawam 115	Line	143	165
Shawington 115 - Fairmont 115	Line	593	764
Chicopee 115 - Fairmont 115	Line	339	439
Piper 115 - Fairmont 115	Line	339	439
E. Springfield 115 - Clinton 115	Line	250	371
E. Springfield 115 - Breckwood 115 CKT1	Line	250	371
E. Springfield 115 - Breckwood 115 CKT2	Line	250	371

b. Interface Limits

Interface limits vary by degree of NEEWS inclusion in the 2011 and 2013 study years, and are assumed to remain at 2013 levels in the 2018 and 2030 study years, since the transmission system is assumed to remain unchanged after 2013. 2011 Interface limits are consistent with those published in the ISO-NE October 26, 2006 Draft *Regional System Plan*[34] and the ISO-NE FERC Form No. 715.[35] Post-NEEWS East/West Interface and Connecticut Import limits have been projected by Northeast Utilities. Figure G.33 summarizes assumed interface limits by study year and degree of inclusion of NEEWS.

[34] *Draft Regional System Plan*, ISO-NE, Page 38, Table 4-5, October 26, 2006.
[35] *ISO-NE FERC Form No. 715*, Pages 6-3 through 6-6, March 31, 2007.

Figure G.33: Major Interface Limits by Study Year and Degree of NEEWS Inclusion

Interface Constraint	2011 Limit		2013 Limit: Partial-NEEWS		2013 Limit: Full-NEEWS	
	Summer Max (MW)	Summer Min (MW)	Summer Max (MW)	Summer Min (MW)	Summer Max (MW)	Summer Min (MW)
New Brunswick - New England	1,000	-250	1,000	-250	1,000	-250
Orrington South	1,200	NL	1,200	NL	1,200	NL
Surowiec South	1,250	NL	1,250	NL	1,250	NL
Maine-New Hampshire	1,550	-1,700	1,525	-1,700	1,525	-1,700
New England North-South	2,700	NL	2,700	NL	2,700	NL
New England East-West	2,400	-2,400	3,100	-3,100	3,500	-3,500
Boston Import	4,900	NL	4,900	NL	4,900	NL
SEMA: Southeast MA	NL	NL	NL	NL	NL	NL
SEMARI: SE MA RI Ex	3,000	NL	3,000	NL	3,000	NL
Connecticut Import	2,500	-2,030	3,200	-3,200	3,600	-3,600
SW Connecticut Import	3,650	NL	3,650	NL	3,650	NL
Norwalk-Stamford Import	1,650	NL	1,650	NL	1,650	NL
New York - New England	1,175	-1,150	1,175	-1,150	1,175	-1,150

Note: NL=No Limit

c. Contingencies and Line Constraints

First-order N-1 contingencies corresponding to the varying degrees of transmission inclusion are provided by the Companies and are included in the model. Second-order (N-2) contingencies are not modeled. 115kV line and contingency constraints that bind frequently in the 2018 and 2030 study years are assumed to spur mitigation efforts to avoid high congestion costs via equipment upgrades, and are concurrently removed as constraints from the model.

d. Transmission Outages

Transmission outages are not modeled.

APPENDIX H: EVALUATION METRICS

This Appendix describes the Evaluation Metrics and reports the results for all of the cases studied (Scenario-Resource Solution-Year combinations).

I. DESCRIPTION OF METRICS

The DAYZER simulations produce an enormous quantity of detailed information on the operation of each generating unit in the ISO-NE system and the economics of serving loads under the assumed conditions. These can be distilled to produce summary statistics that address the criteria in PL 07-242 in order to evaluate the resource solutions, which we term "Evaluation Metrics." These measures also are consistent with the CEAB "Preferential Criteria for Evaluation of Energy Proposals" (Effective December 1, 2004); however, the Preferential Criteria are more project-based (as opposed to generic resources) and therefore the measures examined in this report do not perfectly map into the Criteria. These various metrics fall into several categories, reflecting diverse objectives and criteria for evaluating the performance of resource solutions.

a. Total Annualized Going-Forward Resource Cost of Meeting Load

Resource cost represents the economic value of resources consumed in supplying Connecticut loads, without regard to who incurs those costs or the possible ratemaking treatment of such costs. These are annualized "going-forward" generation and DSM-related costs that do not take into account the value of capital in existing or already-committed capacity (i.e., they do not account for "embedded" capital cost) but do account for the annualized capital costs of new generation plant in Connecticut and the capitalized cost of DSM programs. The costs of resources located outside of Connecticut are included by pricing imported energy and capacity at market prices. The value of energy and capacity exported outside of Connecticut is counted as a credit, again valued at market prices. More specifically, total going-forward annual resources costs for Connecticut include:

- Capital carrying costs on new generation located in Connecticut (this includes the new baseload plant in the Nuclear and Coal Solutions, and new CCs or CTs used to meet ISO-NE's required reserve margin).
- Fixed O&M for all operating plants in Connecticut.
- Variable O&M for all operating plants in Connecticut.

- Fuel and emission allowance costs for operating plants in Connecticut
- RPS costs, i.e., Renewable Energy Credits (RECs) and alternative compliance payments to meet Connecticut RPS requirements, both priced at a nominal level of $55/MWh according to the Connecticut rules regarding RPS.
- The cost of imports of energy, priced at the load LMP in Connecticut, minus the value of exports priced at the generation-weighted average generator LMP in Connecticut.
- The cost of capacity imports or the value of capacity exports priced at the ISO-NE capacity price, which is discussed in Appendix A.
- Demand-side program costs, including the annual costs of administering demand response programs and an annuitized cost of efficiency investments (using a 10-year annuity equivalent at a real after-tax weighted average cost of capital of 7%).

While these total going-forward resource costs are not precisely customer costs (which depend on many factors, including ratemaking treatment) this is the single most comprehensive measure of cost that must be recovered in the long run from customers in order for utilities to provide economic service. Therefore, they correspond to the CEAB Preferential Criteria II.B and II.C over the long run.

b. Market-Based Generation Cost

In Connecticut's restructured retail environment, customers' generation service rates are determined by the procurement costs incurred by the Companies and other load serving entities as they pay for energy, capacity and ancillary services supplied from the ISO-NE market. The cost elements are:

- Generation Service Charges
  - Energy cost, based on the hourly load times the load bus locational marginal prices (LMPs), a standard spot market-based measure of the cost of serving load in an LMP market.
  - Capacity cost, given by the peak load times the required planning reserve margin of approximately 16.6% times the capacity price. As discussed in Appendix A, the capacity price is given by the net cost of new entry (Net CONE) when the market is in supply-demand balance. In 2011, the market is in surplus and the price is set by the $4.50/kW-month floor that has been established by ISO-NE.
  - Fast-start costs, or local forward reserve market (LFRM) costs are based on the formulas ISO-NE uses to allocate LFRM and FRM costs across ISO-NE, which result in Connecticut customers having to pay approximately 45% of LFRM costs incurred in

Connecticut, depending on market conditions, as discussed in Appendix A. LFRM costs incurred in Connecticut are given by the required reserves (approximately 1,300 MW, given by the capacity of the largest unit) multiplied by the LFRM price, which is assumed to be at the cap due to the lack of surplus of fast-start capacity in Connecticut. The cap is given by $14/kW-month minus the capacity price.

- Revenues from financial transmission rights (FTRs), assuming load serving entities have FTRs providing revenues sufficient to cover 75% of the congestion costs incurred between Connecticut generators and Connecticut load (calculated by multiplying the load versus the generators in Connecticut.
- A loss adjustment is needed because DAYZER double-counts losses. First, the load forecast already includes losses, which sets the total amount of generation customers must pay for. Second, marginal losses are calculated as part of the LMP in order to produce efficient dispatch signals (the loss component of the LMP at each node is given by the price at the reference bus times a nodal marginal loss factor drawn from a database of loss factors under similar load conditions). In order to avoid double-count losses, the loss component is reduced to that at the Connecticut generators by subtracting the difference between the load's and generators' loss components from the load's LMP.
- The cost of spinning reserves and uplift are each calculated from the Connecticut load ratio share of ISO-NE payments to all generators in ISO-NE. Both quantities are modeled explicitly in DAYZER.
- Supplier risk premium, estimated at 15% to account for the risks that wholesale suppliers assume when bidding to serve retail loads. These include credit, price and volume risks, and represent the difference between the pure "market cost" of resources and the prices typically observed in the market for serving retail loads.

- System Benefits Charges
  - Renewable Energy Certificates (RECs) or alternative compliance payments valued at a nominal level of $55/MWh.
  - DSM program costs, including the annual cost of administering demand response programs and the annual cost of efficiency investments. Efficiency investments are not capitalized, as they are in the calculation of Total Annualized Going-Forward Resource Cost, in order to reflect the current rate treatment.

These customer costs are divided by the Connecticut loads to estimate an average customer generation rate, in ¢/kWh. These metrics correspond most closely to CEAB Criteria II.B and II.C.

c. Cost of Service Generation Rates

In addition to calculating customer generation rates under prevailing rules, we also estimate customer generation rates under a hypothetical alternative where Connecticut generators are paid under traditional cost-of-service principles. This proxy cost of service was constructed from the following elements:

- Generation Service Charges
  - Total (going-forward) Resource Costs as described above, but excluding RPS and DSM costs, plus
  - Annualized embedded costs of generators in Connecticut, consisting of estimates of annualized capital payments:
    - For Connecticut generating units that have obtained "reliability-must-run" (RMR) contracts, we use the nominal difference between the Annualized Fixed Revenue Requirement (AFRR) and the annual Fixed O&M (FOM) obtained from the RMR dockets and settlement agreements.
    - For the Millstone nuclear unit, an annual capital payment based on the purchase price in 2001 and utility financing assumptions.
    - For recent new units an estimate of annual capital payments based on technology type
    - We assume embedded costs of zero for numerous old, small plants for which FOM is the primary going-forward cost
- System Benefits Charges are calculated the same as in the Market-Based Customer Costs.

These costs are divided by Connecticut loads to estimate an average customer cost under the cost of service accounting in ¢/kWh.

Average customer generation rates are calculated by dividing the total cost by the total load. In turn, a monthly "typical bill" is calculated for a hypothetical customer with 700 kWh of load (prorated in the "DSM-Focus" solution).

d. Electric Reliability

The ISO-NE planning reserve margin (Installed Capacity – Peak Load / Peak Load) and Connecticut planning reserve surplus (relative to the LSR) are calculated to convey differences in electrical reliability, which addresses CEAB Criteria I.B.

e. Fuel Diversity and Security

We report the fuel consumption metrics that are most relevant to the objectives of fuel diversity and security: the quantity of natural gas burned in Connecticut and New England all year and during the peak heating season. We also report the quantities and percentages of other fuels.

f. Load Factor

We calculate the Connecticut load factor (the ratio of average annual load level to system hourly peak, net of DSM) to measure progress toward leveling load by shifting energy from peak to off-peak time, corresponding to CEAB Criteria III.B.

g. Environmental & Renewables

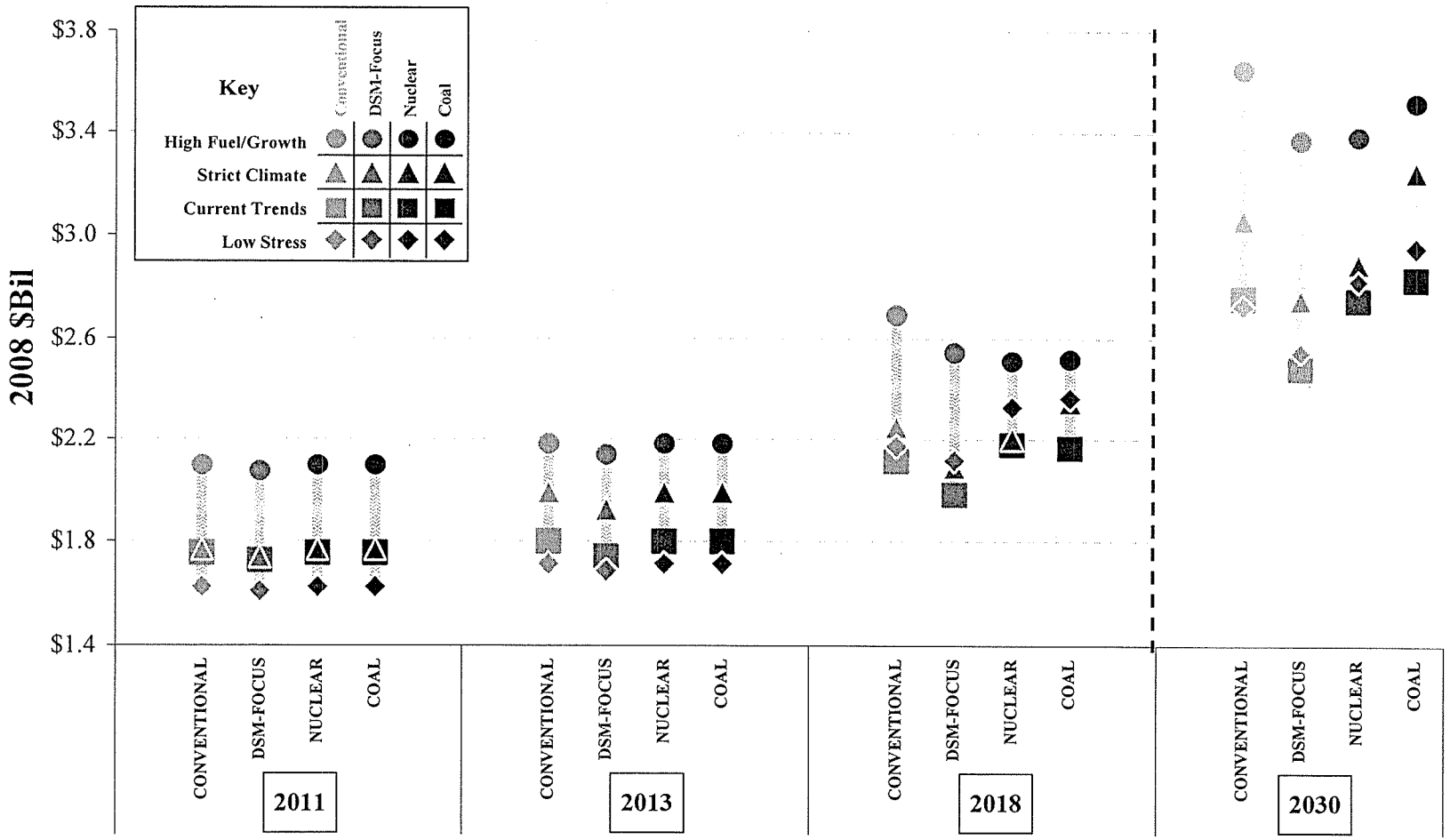
These metrics include annual emissions in ISO-NE and Connecticut of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). The CO_2 emissions can be compared to the RGGI cap.

For RPS compliance, metrics reported are annual renewable energy requirements (state loads x required percentages) and eligible renewable electricity generation.

II. Documentation of Metrics for All Cases

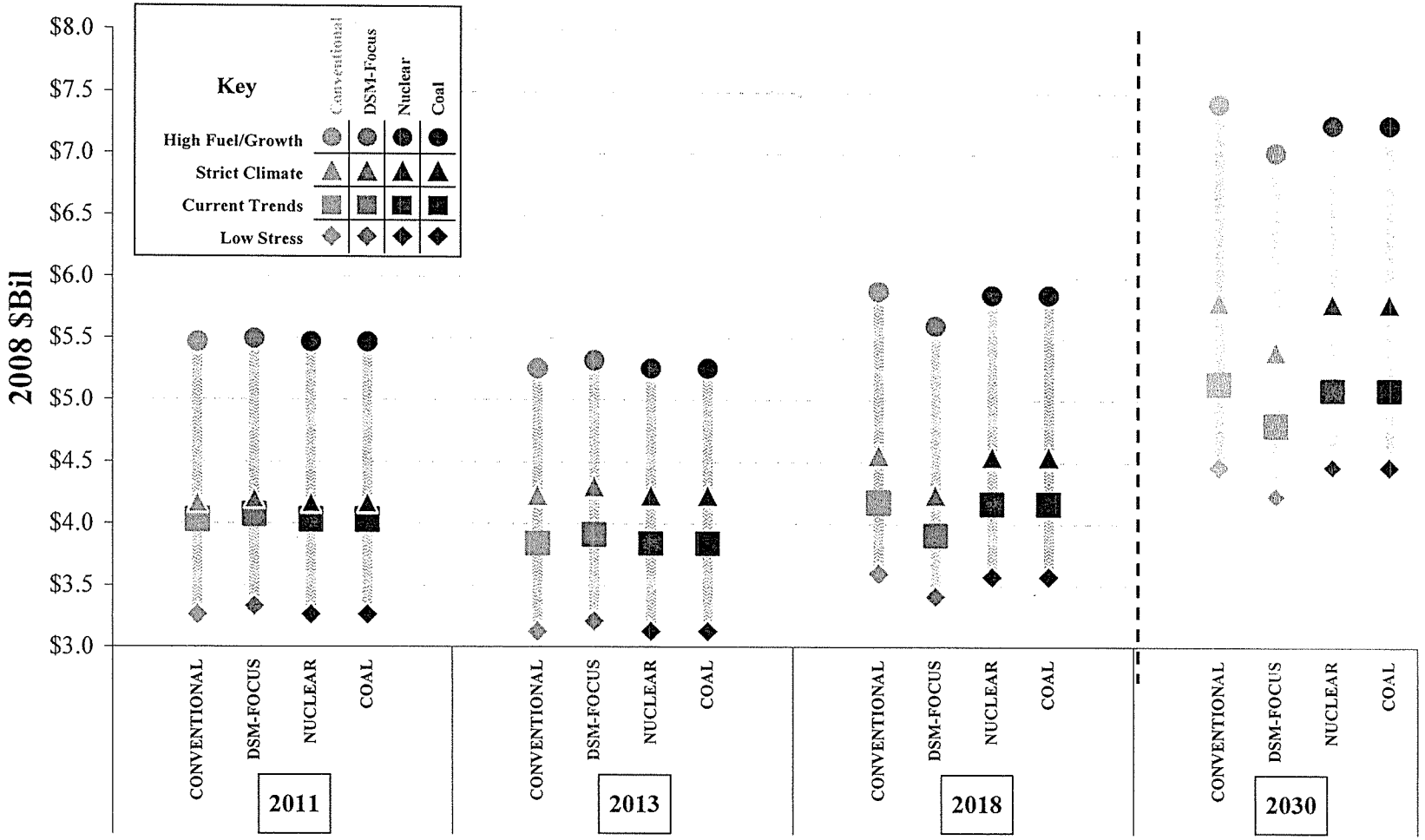
The results for each metric are summarized across all cases in the graphs shown below (a subset of these also appears in Section III of the Report). Immediately following are the detailed metrics results for each case (Scenario-Solution Set-Year combinations).

Figure H.1: Total Going-Forward Resource Cost (Annual)



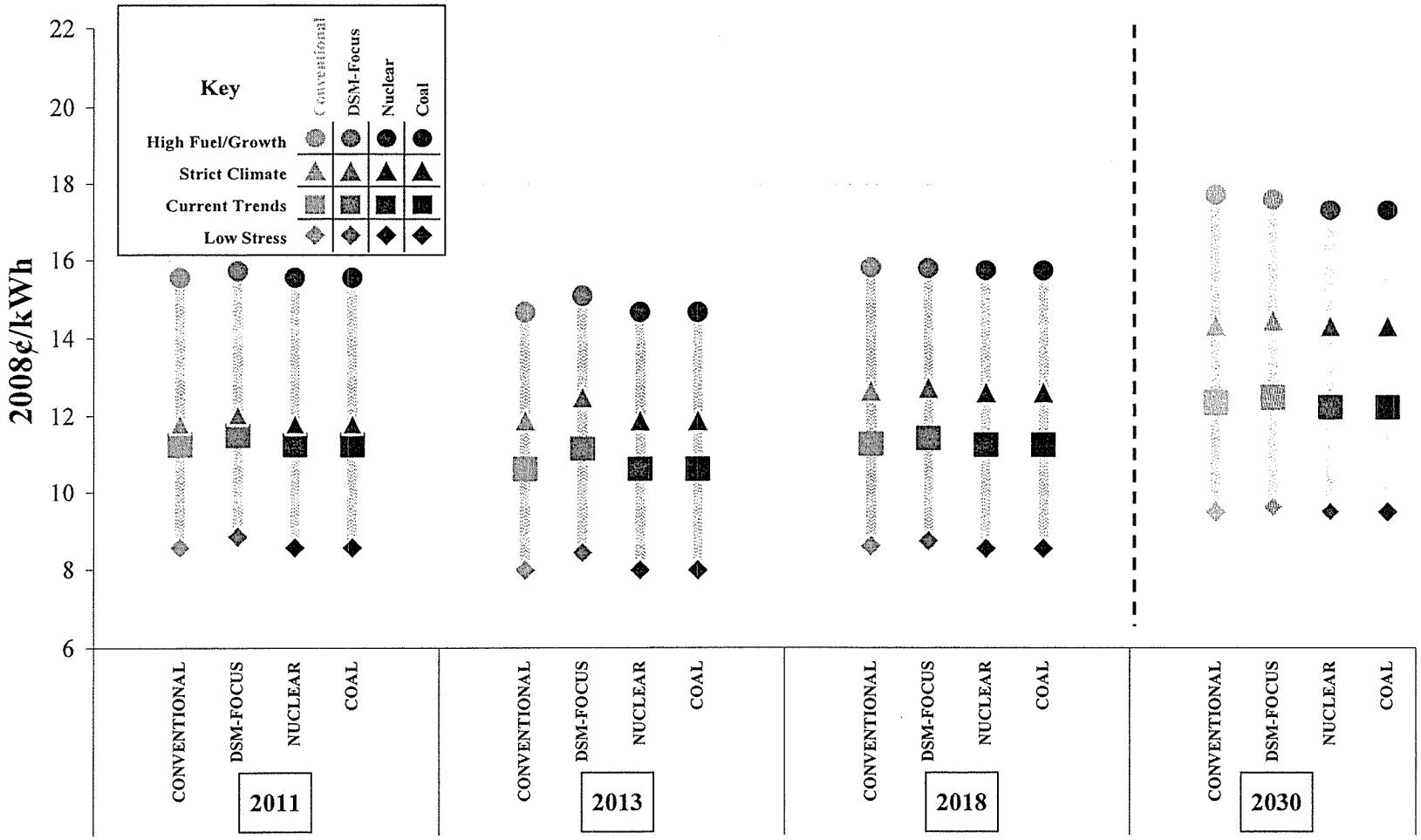
*Total Resource Cost includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs. Note that DSM costs for energy efficiency programs are capitalized over 10 years here; this treatment differs from that in the Customer Cost graphics, where energy efficiency program costs are expensed in the year incurred.

Figure H.2: Total Customer Cost in Market Regime (Annual)



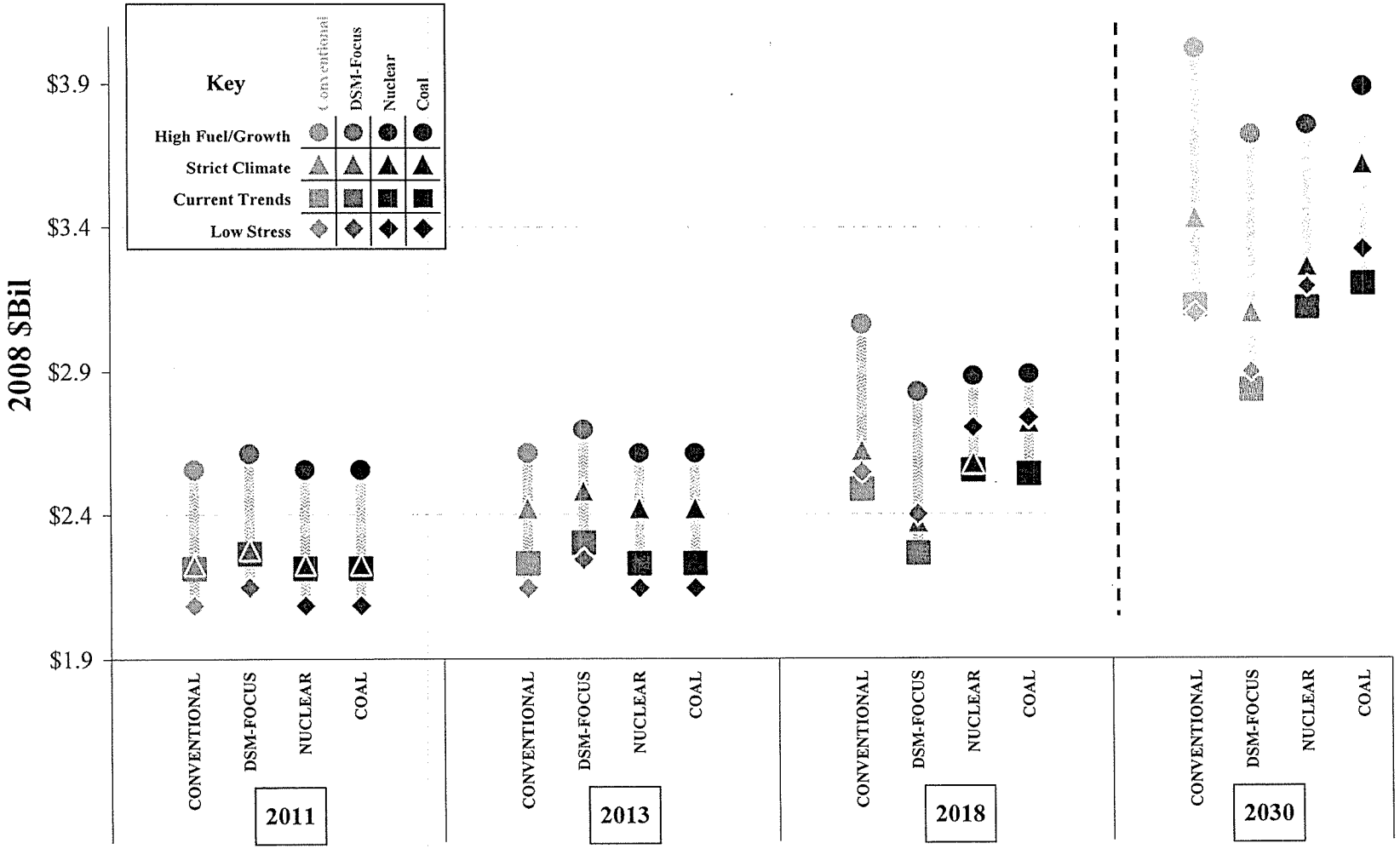
*Total Customer Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Figure H.3: Average Unit Cost in Market Regime



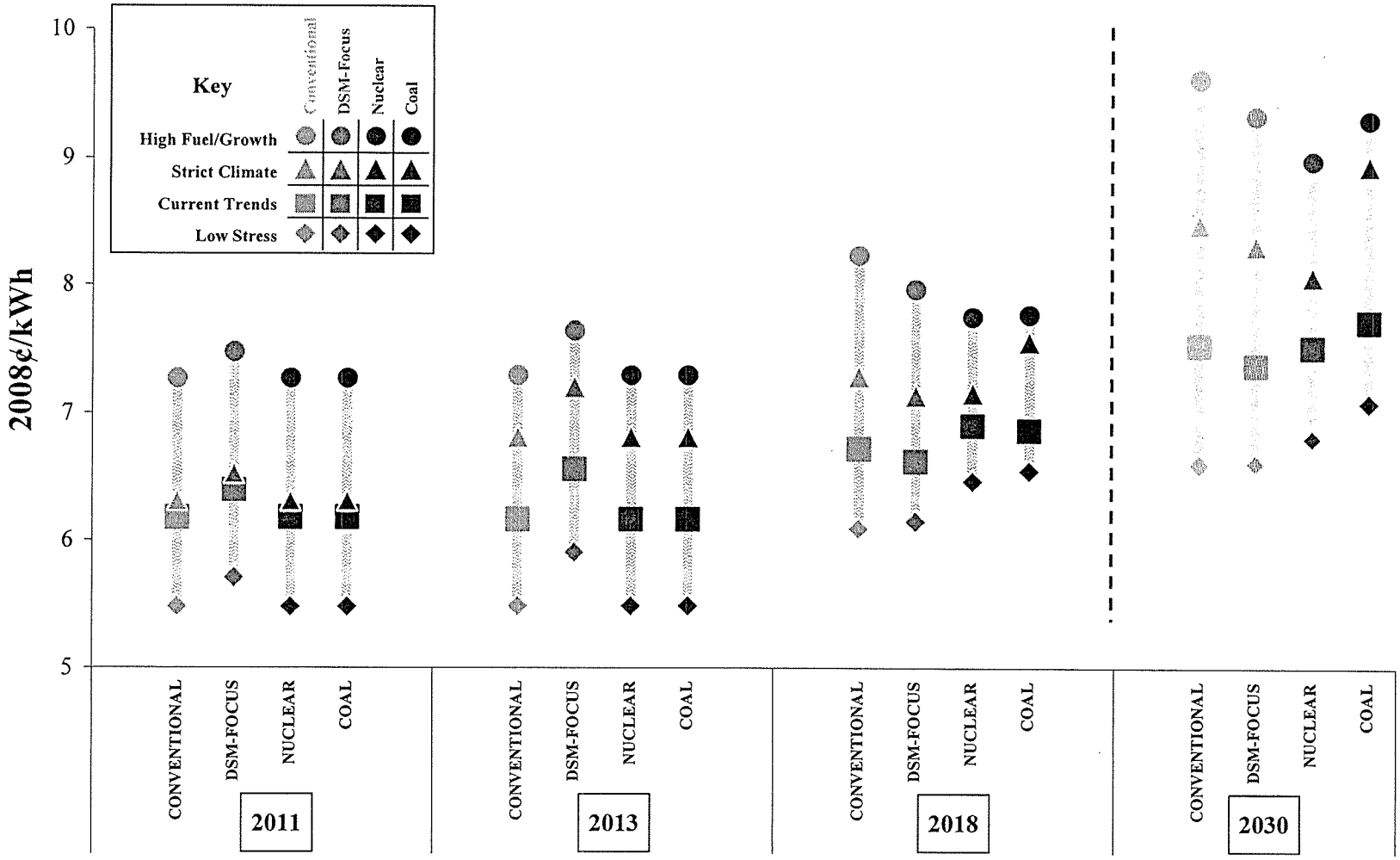
*Average Unit Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Figure H.4: Total Customer Cost in Cost-of-Service Regime



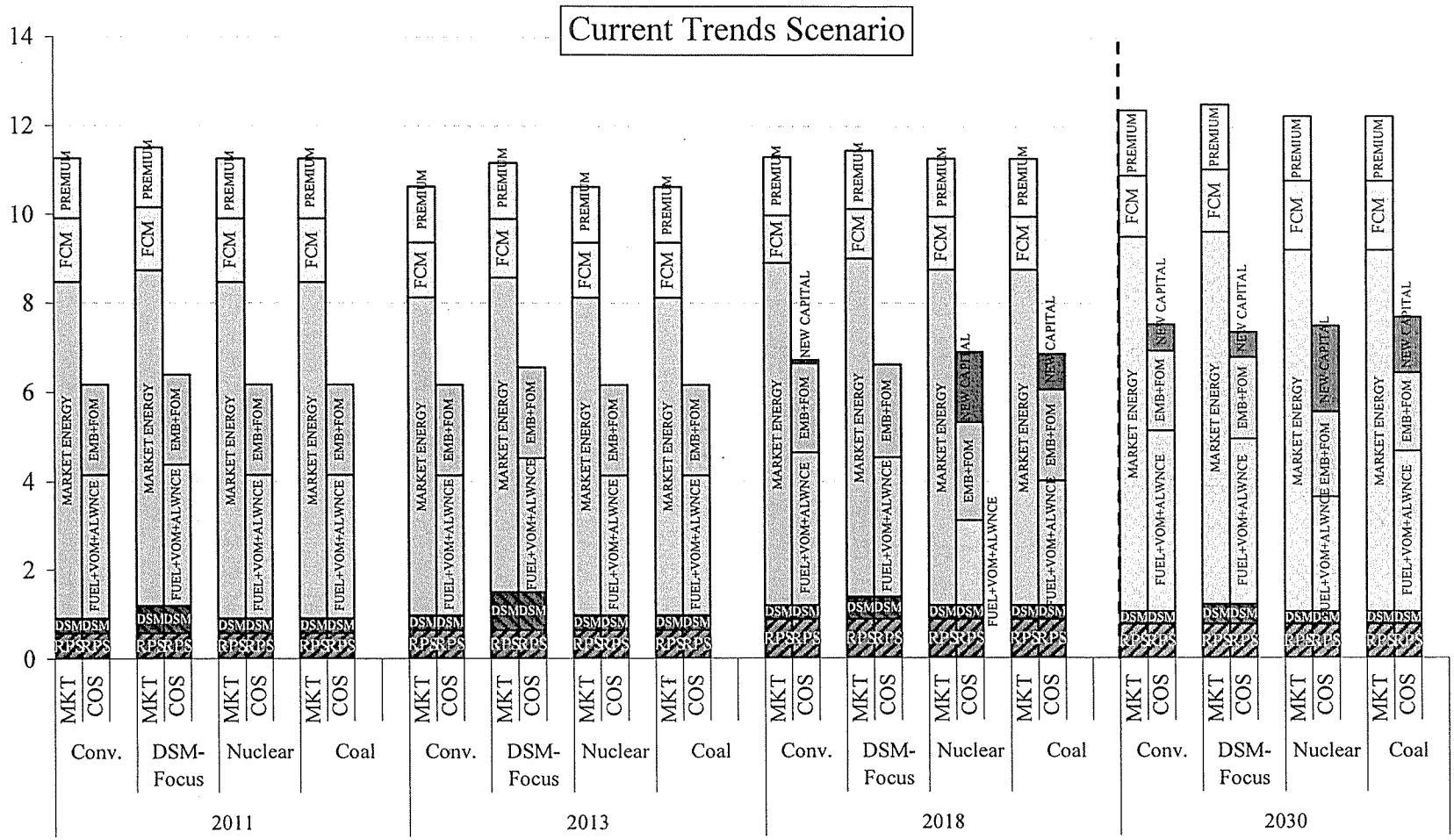
*Total Customer Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figure H.5: Average Unit Cost in Cost-of-Service Regime



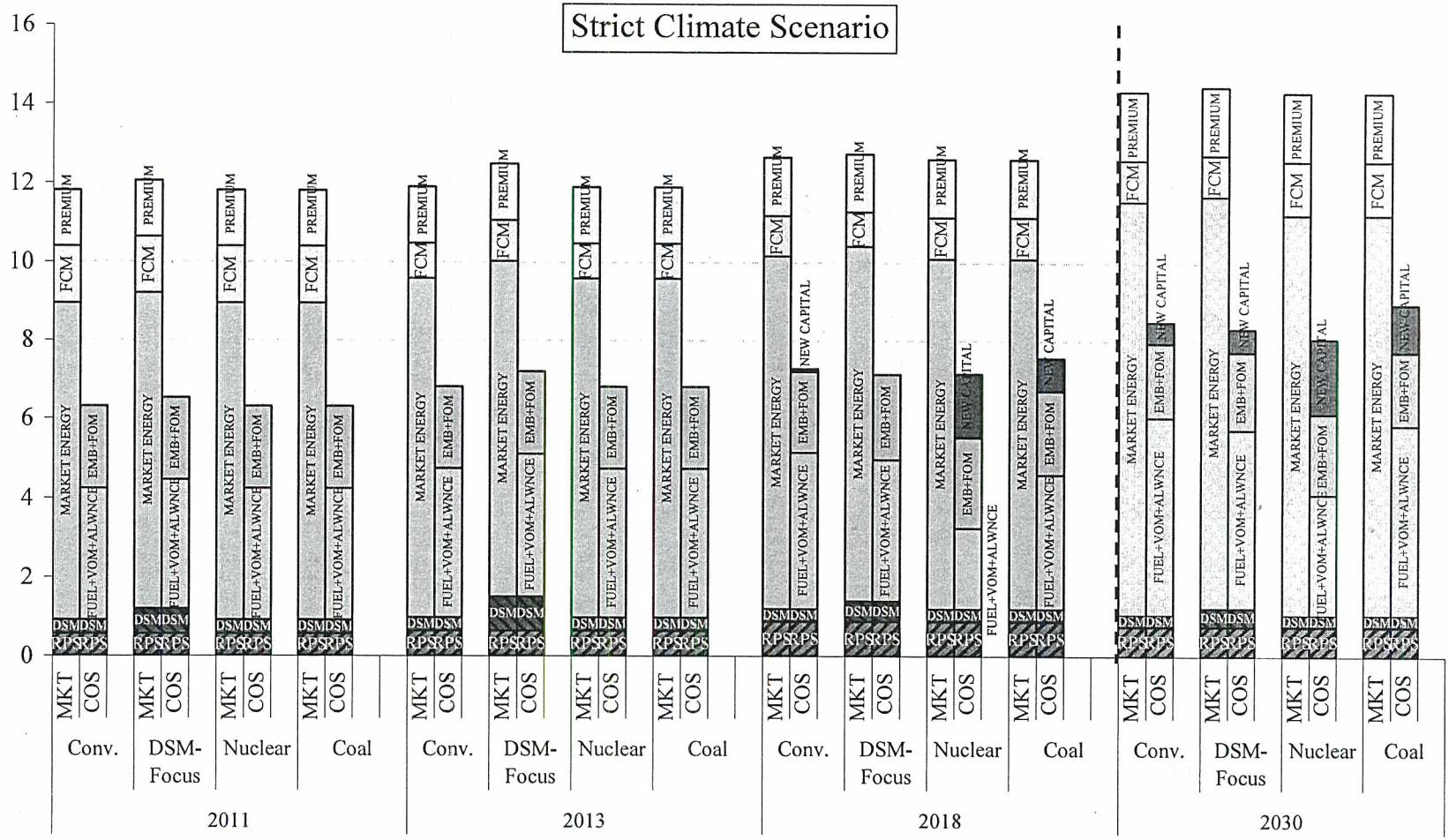
*Average Unit Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figure H.6: Average Customer Cost Components (¢/kWh)



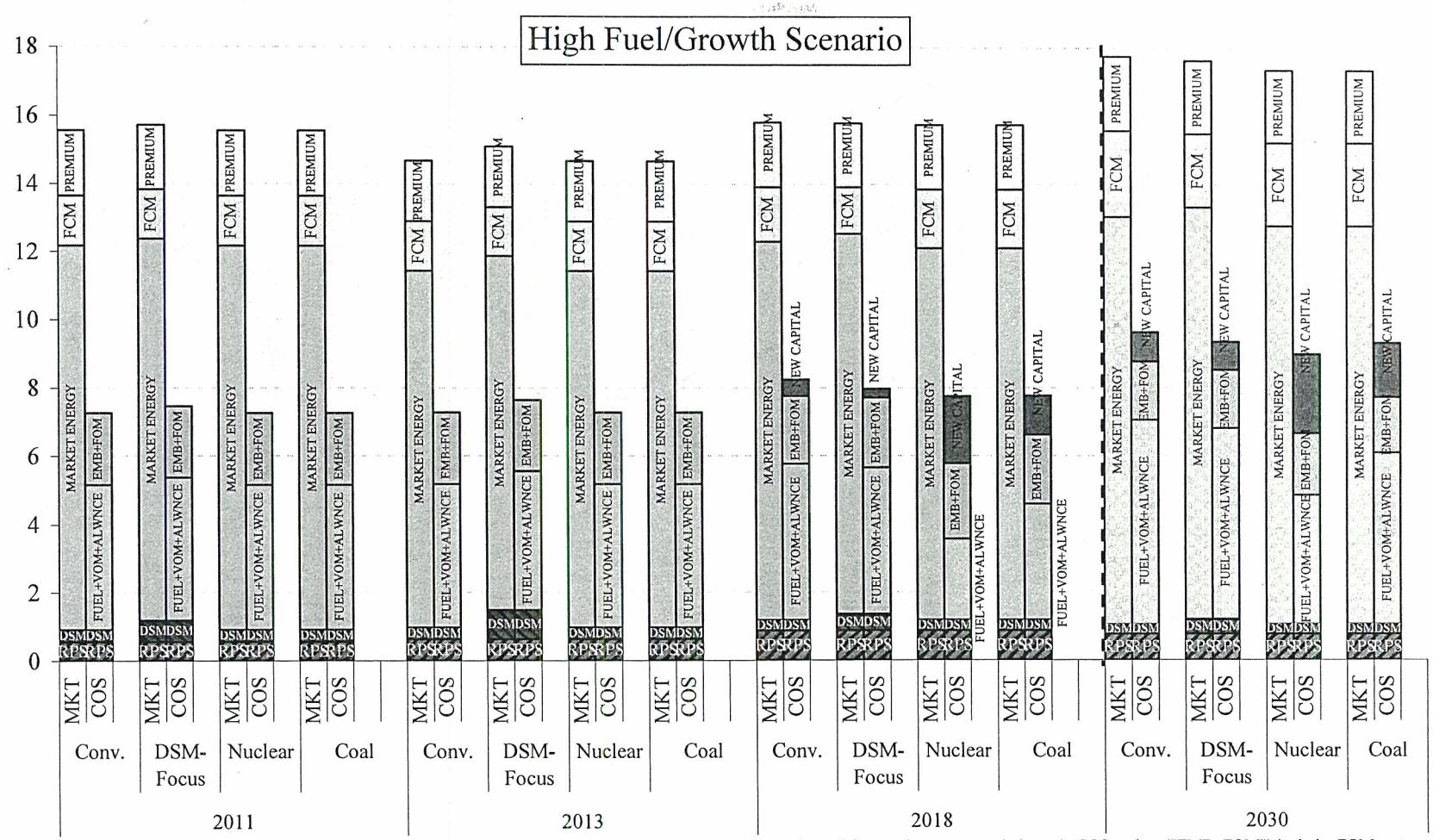
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure H.7: Average Customer Cost Components (¢/kWh)



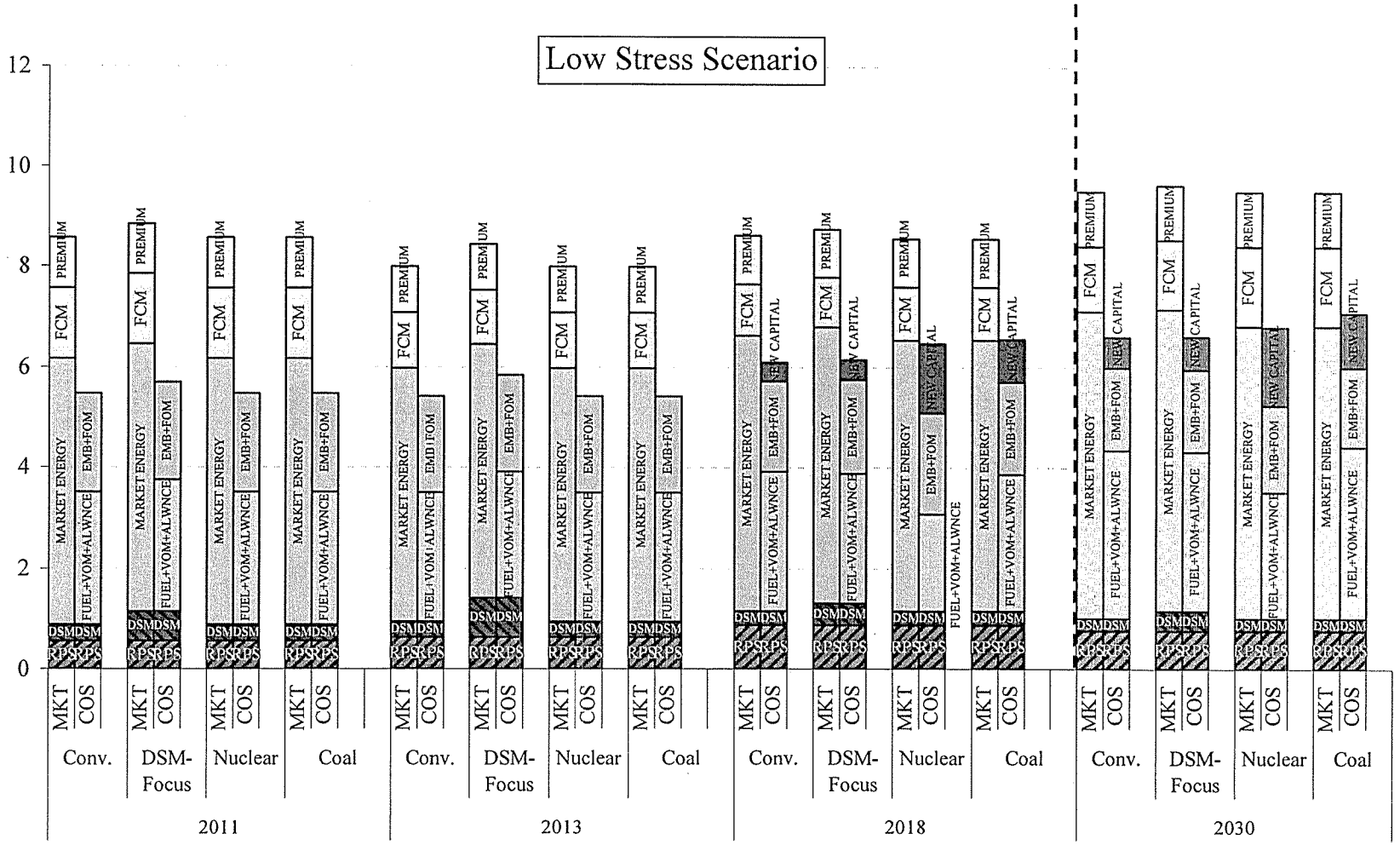
Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure H.8: Average Customer Cost Components (¢/kWh)



Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure H.9: Average Customer Cost Components (¢/kWh)



Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and foreward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

Figure H.10: Connecticut Load Factor (Net of DSM)

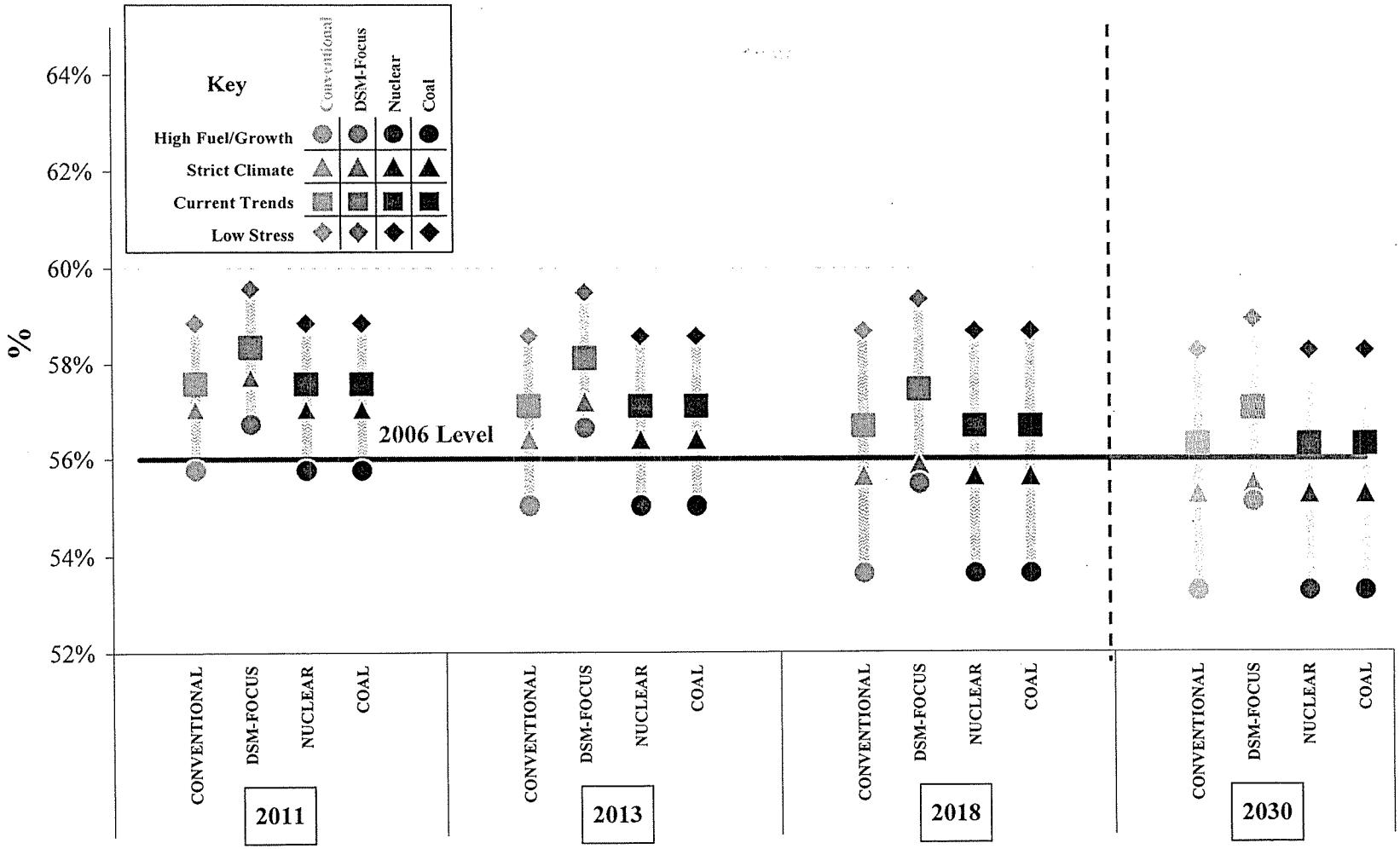
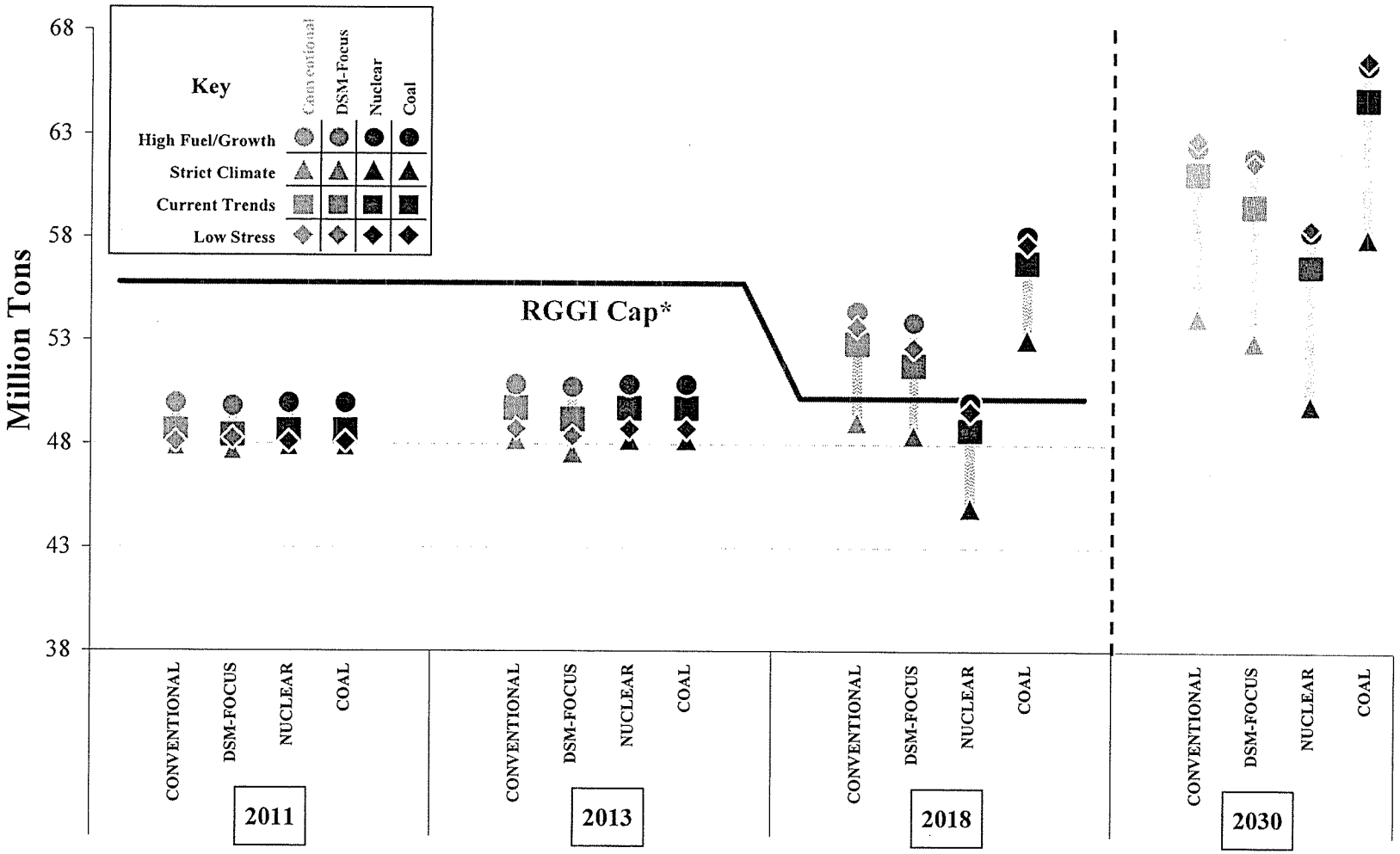


Figure H.11: CO_2 Emissions in ISO-NE



*Emissions and RGGI cap shown here reflect the 6 member states of ISO-NE only. A surplus or deficiency does not indicate whole RGGI-region status.

Figure H.12: Winter (January – February) Power Sector Gas Use in Connecticut

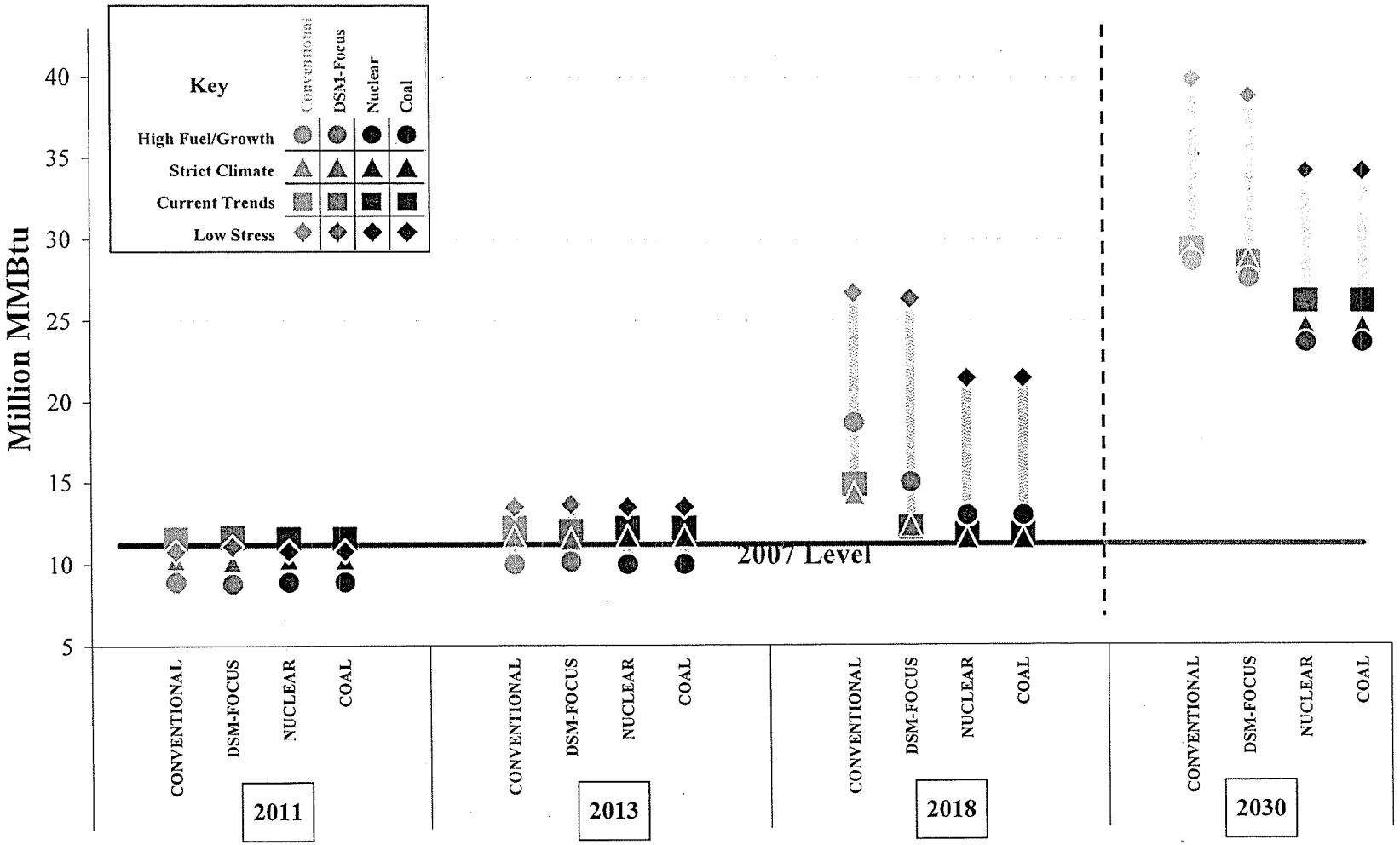


Figure H.13: Winter (January – February) Power Sector Gas Use in ISO-NE

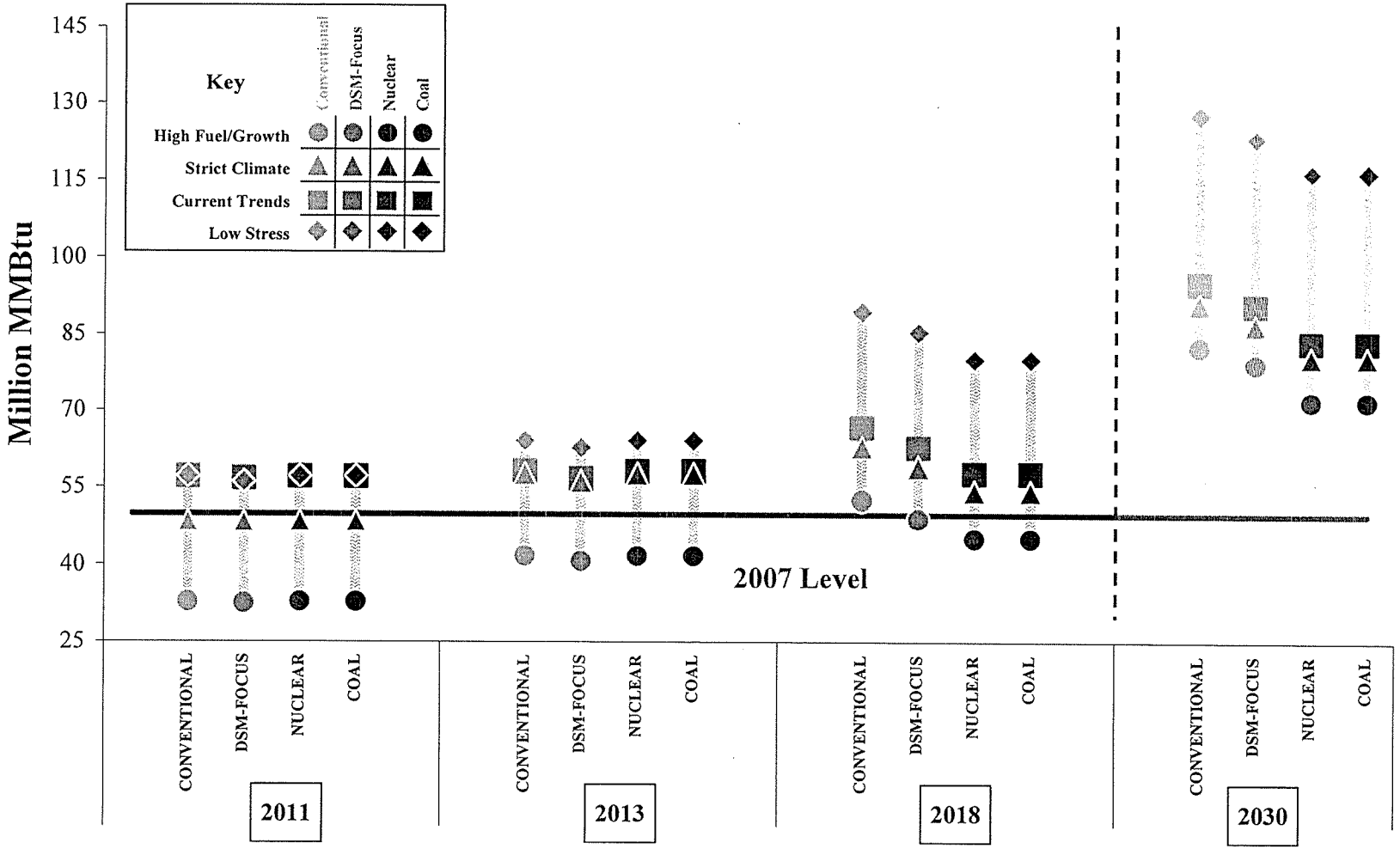


Figure H.14: Annual Power Sector Gas Use in Connecticut

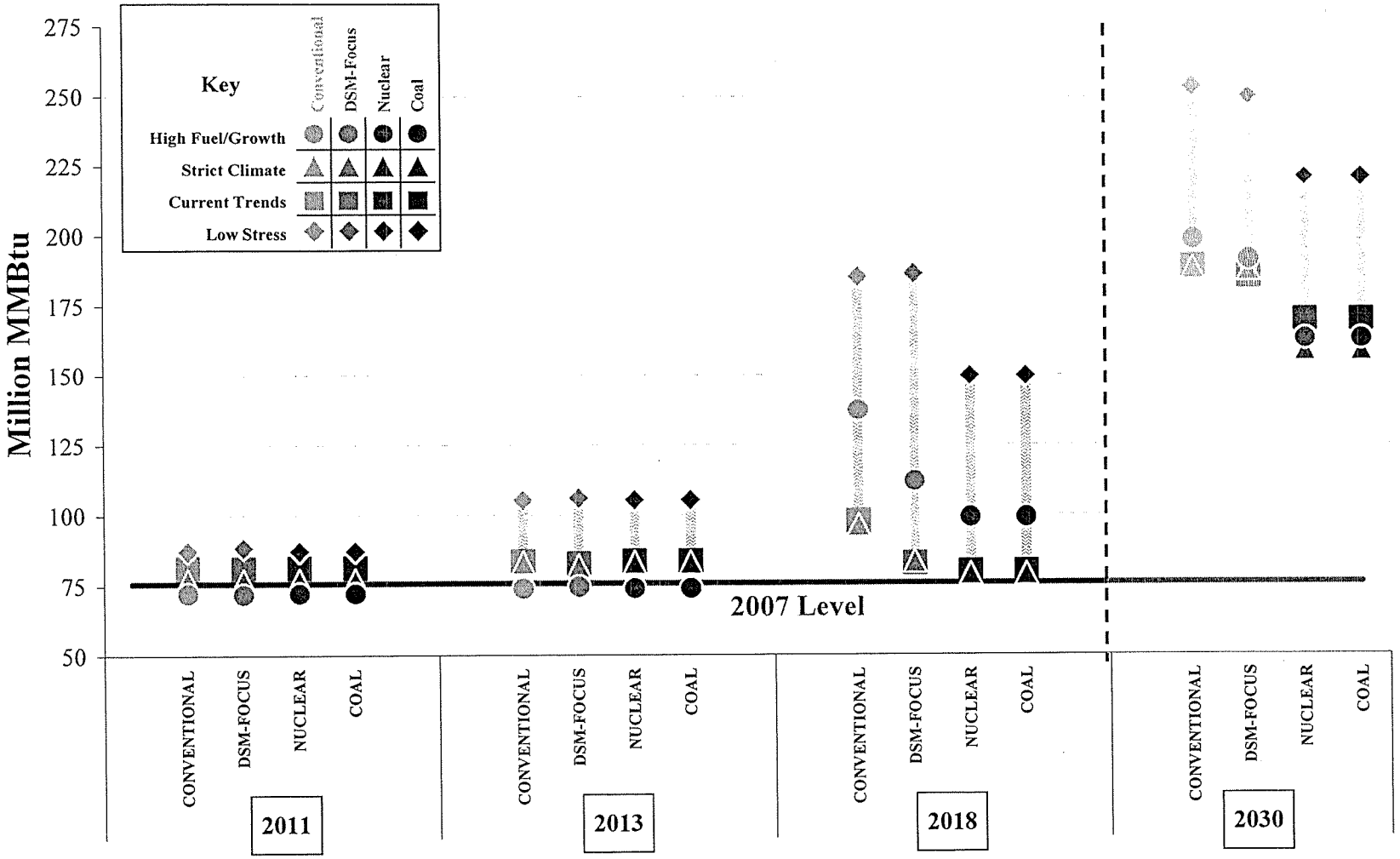


Figure H.15: Annual Power Sector Gas Use in ISO-NE

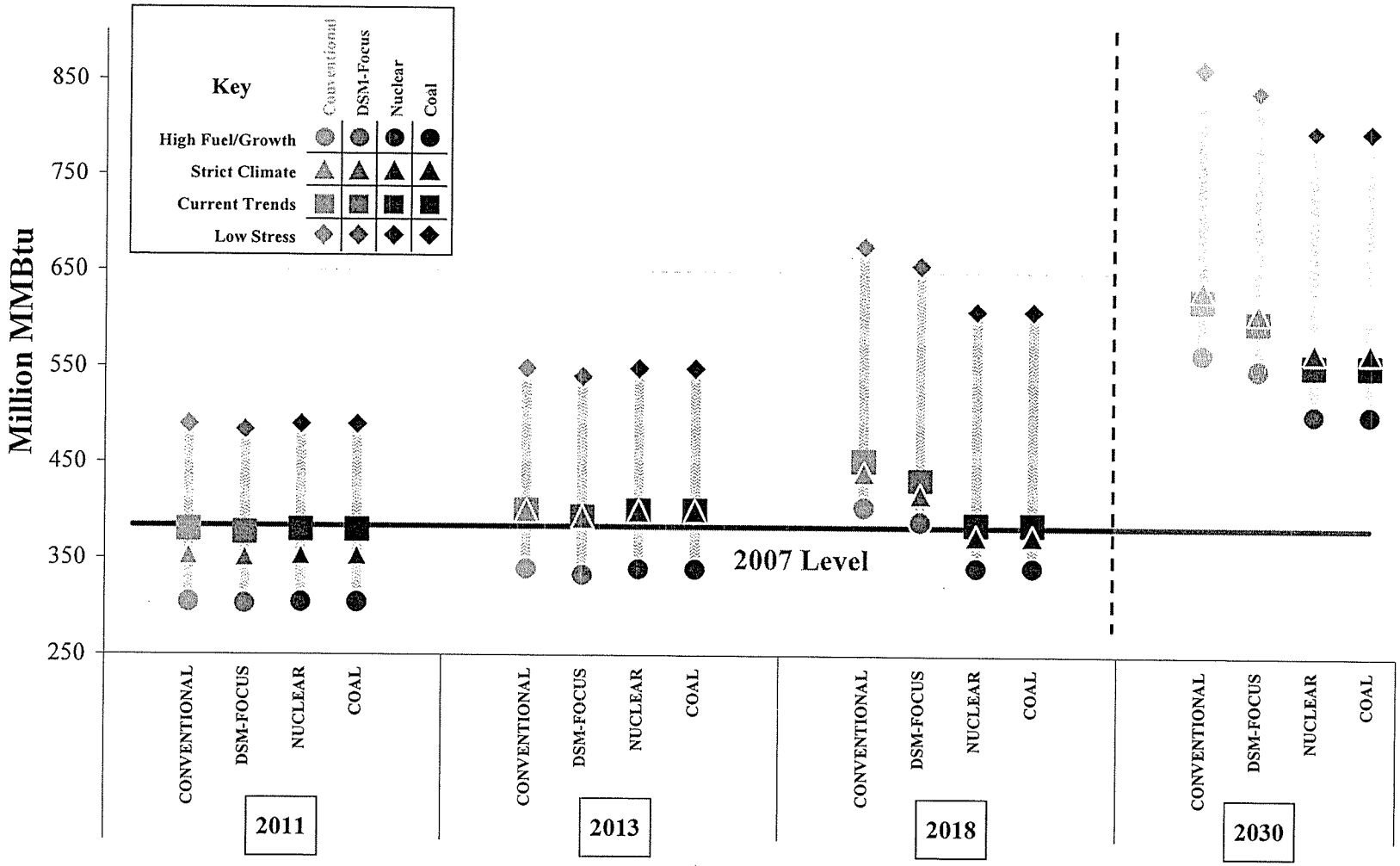


Figure H.16: Connecticut Gas-fired Generation Share of Total Generation

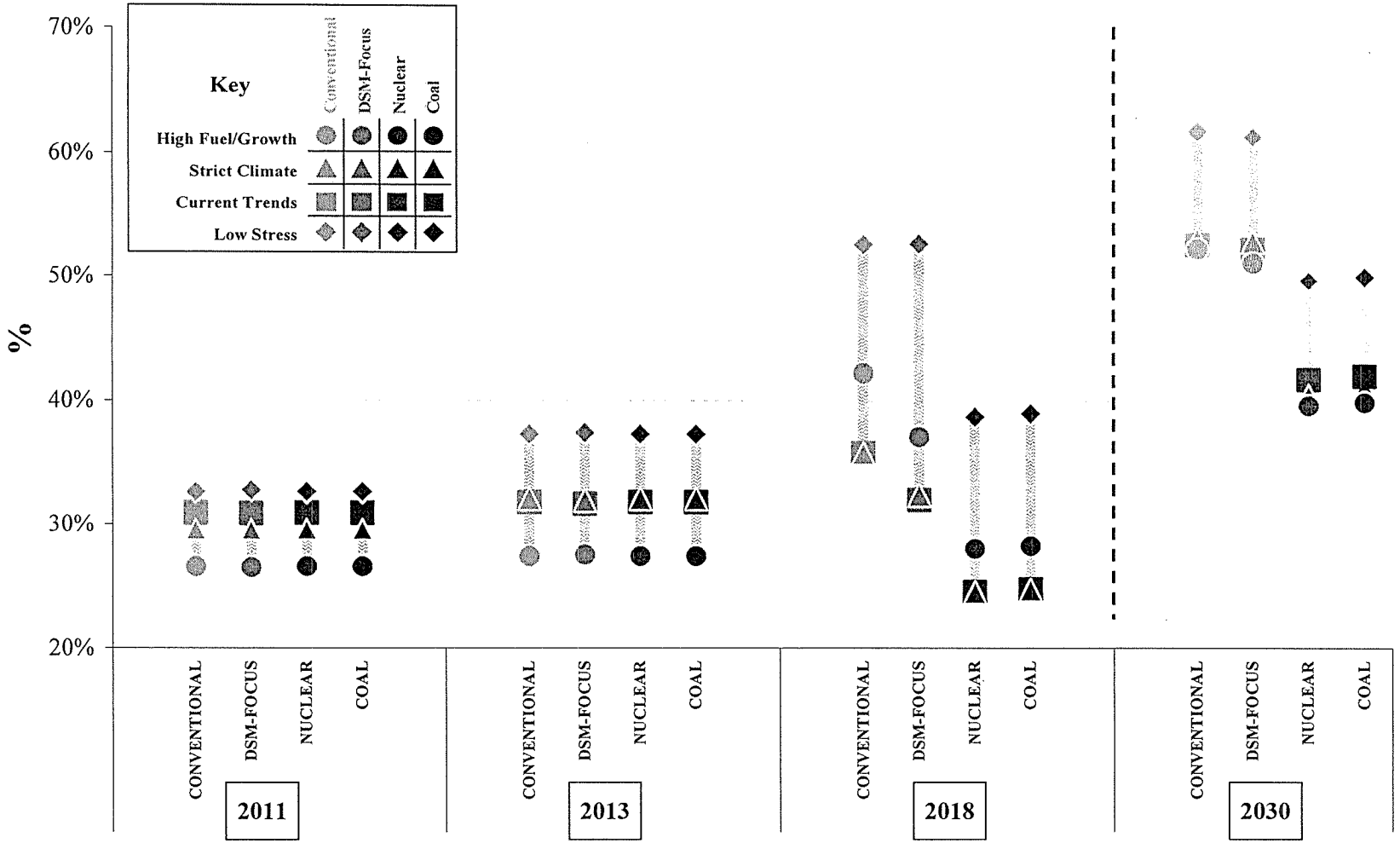


Figure H.17: ISO-NE Gas-fired Generation Share of Total Generation

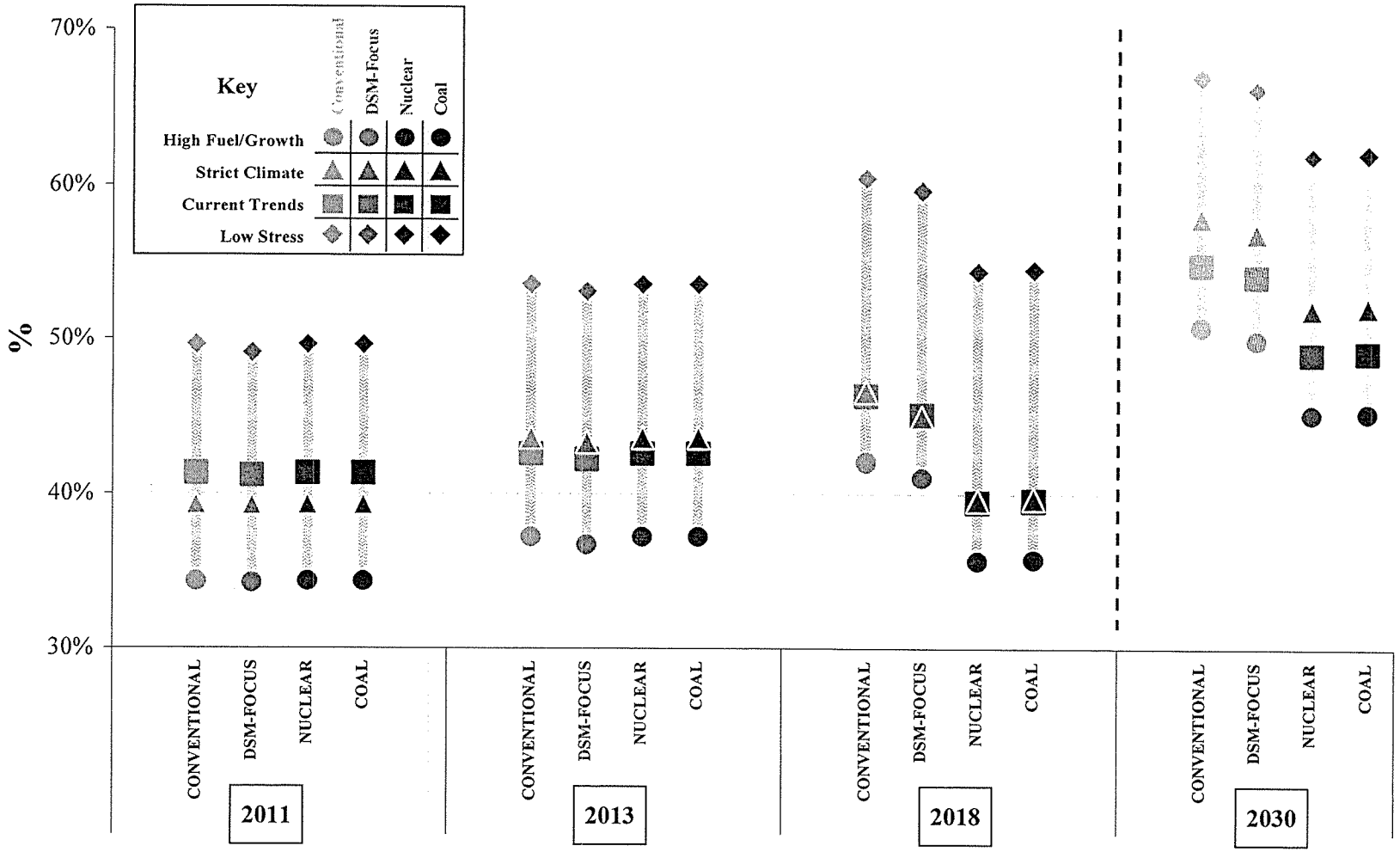


Figure H.19: Connecticut Fuel Mix (Cumulative Generation in TWh)

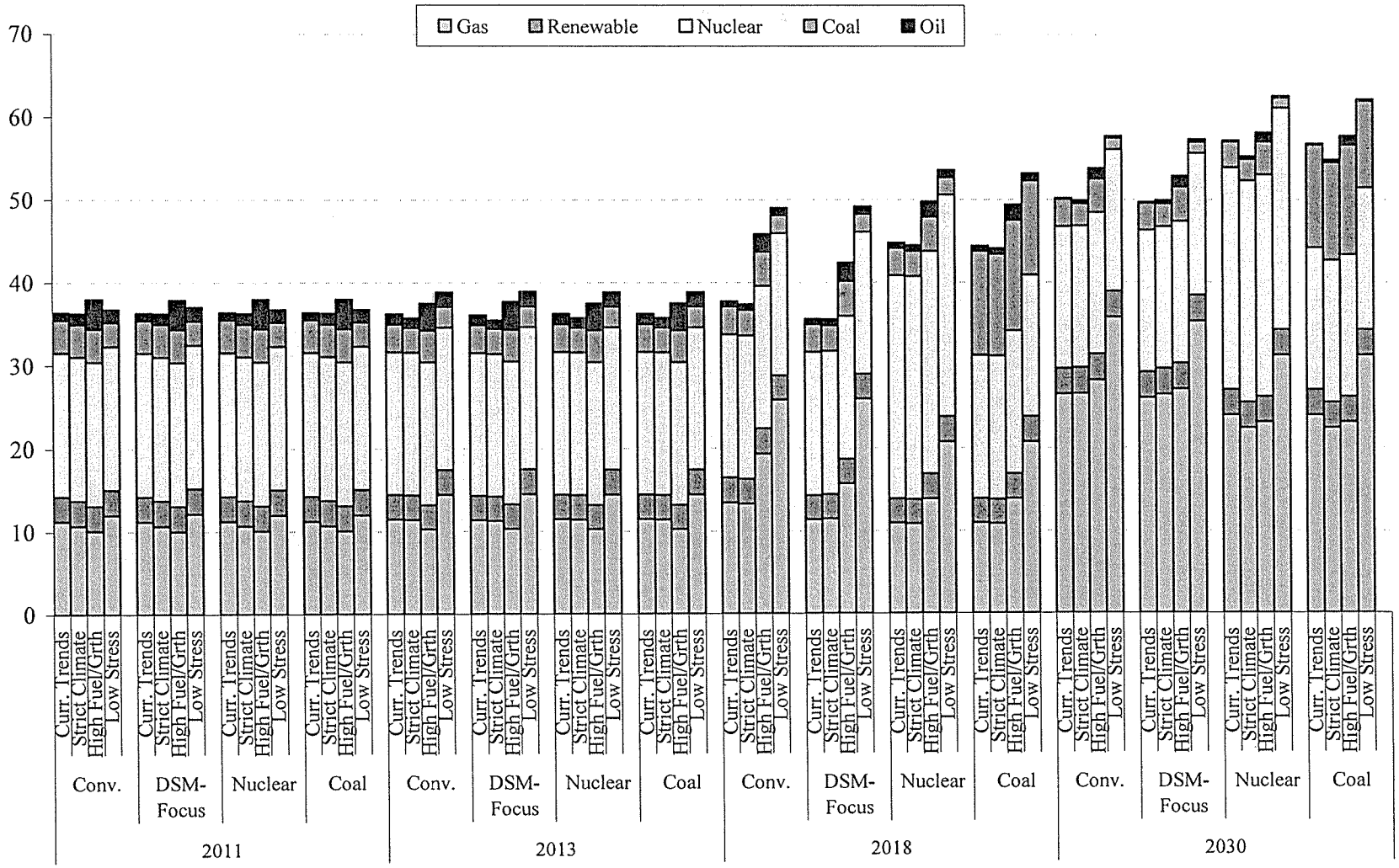
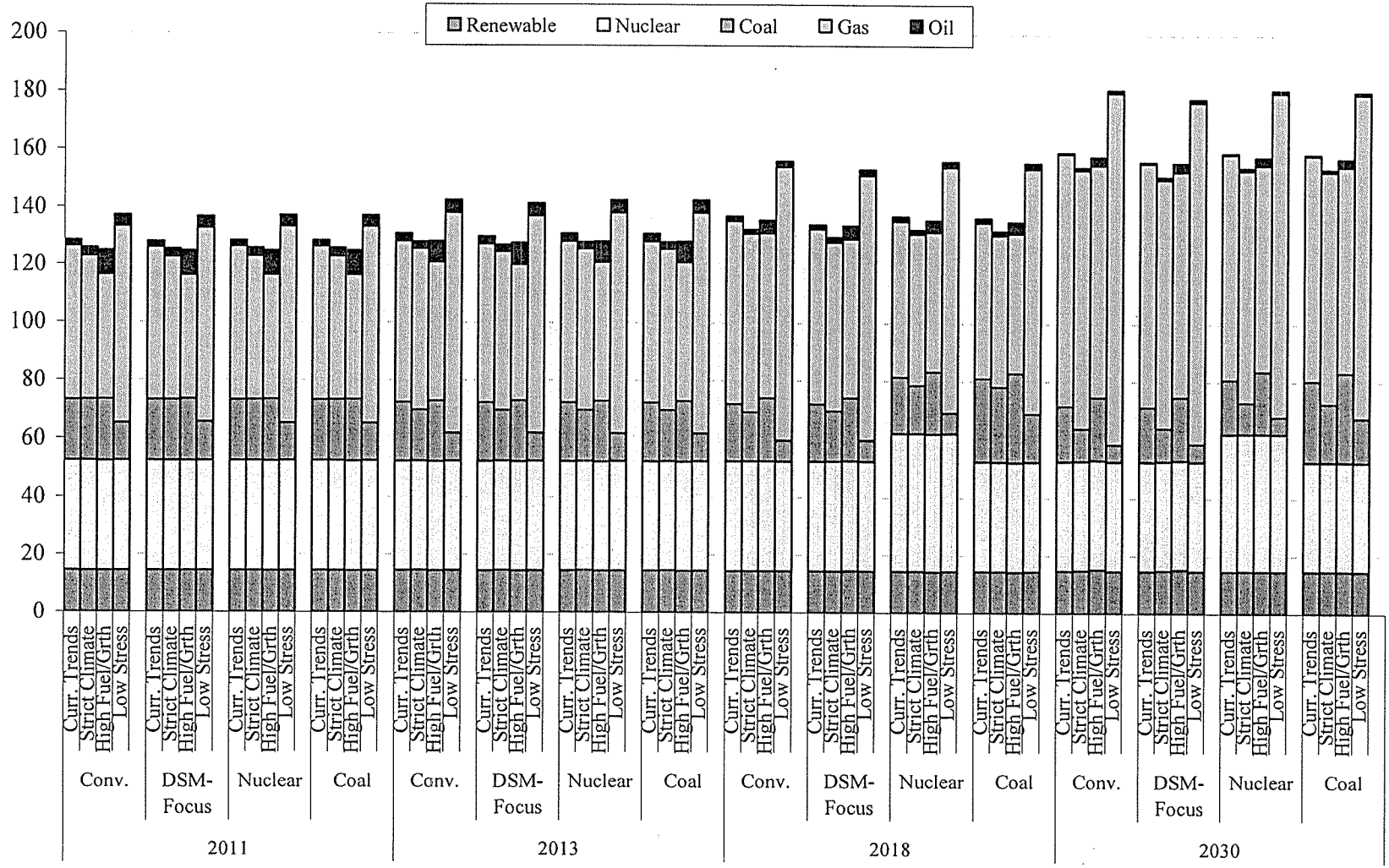


Figure H.20: Total ISO Fuel Mix (Cumulative Generation in TWh)



Summary of Results: 2011 Current Trends Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1 08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77 0	73 9	58%	7,698	35,803,769	36,386,989	-583,215	8,276	8,251	25	4 5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,065	60	202	169	-173	1	76	1,754

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,758	447	-7	-67	22	3	67	3,705	10.35	123	202	325	0.91	4,030	11.26

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,475	413	1,888	5.27	123	202	325	0.91	2,213	6.18

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
21.3%	2,145

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,563,150	17,018,423	81,372,563	31%	57,039,604	86,136,899	379,620,145

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,992,814	11,699	5,248	10,084,834	27,195	7,604
ME	6,079,793	3,592	1,583	6,079,890	3,992	1,681
MA	21,605,001	75,625	20,156	21,577,823	75,632	20,152
NH	7,668,049	24,877	6,773	7,672,330	24,878	6,774
RI	2,703,592	23	467	2,703,592	23	467
VT	603,161	2	2	611,113	2	2
Total	**48,652,410**	**115,817**	**34,230**	**48,729,583**	**131,712**	**36,681**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,310	615,630	3,123,940	36,386,700	35,803,769	11%	8%	3%	1,275,490	1,237,610	$1,622,175
1,956,970	3,020,750	4,979,720	15,965,780	12,739,797						
1,685,120	895,330	2,580,450	38,924,440	62,783,072						
678,940	2,024,940	2,703,880	24,697,540	10,825,805						
92,980	0	92,980	6,466,110	11,944,435						
588,050	439,090	1,027,140	6,117,740	7,699,469						
7,512,370	**6,995,740**	**14,508,110**	**128,558,310**	**141,796,347**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,310	615,630	17,201,880	3,939,820	11,240,540	14,070	866,450	12,121,060	24,265,640	36,386,700
ME	1,956,970	3,020,750	0	584,240	10,215,340	90	186,390	10,401,820	5,563,960	15,965,780
MA	1,685,120	895,330	5,597,860	12,518,620	17,327,470	4,780	895,260	18,227,510	20,696,930	38,924,440
NH	678,940	2,024,940	10,000,870	3,937,230	7,978,970	2,180	74,410	8,055,560	16,641,980	24,697,540
RI	92,980	0	0	0	6,373,130	0	0	6,373,130	92,980	6,466,110
VT	588,050	439,090	5,074,090	0	11,870	4,640	0	16,510	6,101,230	6,117,740
Total	**7,512,370**	**6,995,740**	**37,874,700**	**20,979,910**	**53,147,320**	**25,760**	**2,022,510**	**55,195,590**	**73,362,720**	**128,558,310**

Summary of Results: 2011 Current Trends Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM + 1.04 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
76.7	73.8	58%	6,926	35,400,744	36,328,686	-927,937	8,076	8,251	-175	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,061	60	200	151	-184	-9	94	1,726

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,717	436	-5	-67	25	3	67	3,652	10.32	220	200	420	1.19	4,072	11.50

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,431	413	1,845	5.21	220	200	420	1.19	2,265	6.40

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
22.1%	2,360

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,647,589	16,942,276	81,113,617	31%	56,649,966	85,559,983	376,927,551

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,954,491	11,628	5,218	10,044,293	27,078	7,572
ME	6,063,822	3,605	1,583	6,063,897	3,995	1,681
MA	21,490,783	75,457	20,101	21,461,937	75,461	20,096
NH	7,660,440	24,866	6,769	7,664,564	24,867	6,770
RI	2,667,989	23	461	2,667,989	23	461
VT	603,041	2	2	610,900	2	2
Total	**48,440,566**	**115,581**	**34,134**	**48,513,580**	**131,425**	**36,582**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,180	615,600	3,123,780	36,328,369	35,400,744	11%	8%	3%	1,275,420	1,237,550	79,969,402
1,958,750	3,020,750	4,979,500	15,922,460	12,739,797						
1,685,040	912,770	2,597,810	38,720,780	62,783,072						
678,720	2,024,870	2,703,590	24,681,840	10,823,805						
92,980	0	92,980	6,384,500	11,944,435						
587,930	439,060	1,027,040	6,117,420	7,699,469						
7,511,650	**7,013,050**	**14,524,700**	**128,155,369**	**141,393,322**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,508,180	615,600	17,201,880	3,935,690	11,210,370	12,059	844,590	12,067,019	24,261,350	36,328,369
ME	1,958,750	3,020,750	0	583,930	10,169,420	70	189,340	10,359,030	5,563,430	15,922,460
MA	1,685,040	912,770	5,597,860	12,510,830	17,142,720	4,250	867,310	18,014,280	20,706,500	38,720,780
NH	678,720	2,024,870	10,000,870	3,936,560	7,965,840	2,110	72,830	8,040,820	16,641,020	24,681,840
RI	92,980	0	0	0	6,291,520	0	0	6,291,520	92,980	6,384,500
VT	587,980	439,060	5,074,090	0	11,710	4,580	0	16,290	6,101,130	6,117,420
Total	**7,511,650**	**7,013,050**	**37,874,700**	**20,967,010**	**52,791,620**	**23,069**	**1,974,270**	**54,788,959**	**73,366,410**	**128,155,369**

Summary of Results: 2013 Current Trends Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM + 1 0% loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
72.7	70.2	57%	7,229	36,164,316	36,239,984	-75,664	8,429	8,251	178	3.7	10.3	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,022	63	231	149	-130	8	103	1,799

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,631	377	-4	-64	21	3	72	3,491	9.65	121	231	352	0.97	3,843	10.63

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,465	413	1,878	5.19	121	231	352	0.97	2,230	6.17

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.2%	2,292

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,168,538	17,301,526	83,585,989	32%	58,197,697	89,611,741	400,263,330

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,808,968	9,264	4,757	9,944,981	24,997	7,080
ME	6,431,259	4,265	1,774	6,432,590	4,704	1,884
MA	22,119,220	74,473	19,975	22,093,744	74,458	19,966
NH	7,861,319	25,688	6,983	7,865,377	25,689	6,984
RI	2,989,495	26	516	2,989,495	26	516
VT	553,065	2	2	560,351	2	3
Total	**49,763,326**	**113,719**	**34,007**	**49,886,538**	**129,876**	**36,433**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,384,820	616,070	3,000,890	36,239,650	36,164,316	13%	10%	3%	1,131,740	1,257,870	121,971,119
2,093,810	3,020,440	5,114,250	16,573,980	13,866,492						
1,761,630	929,100	2,690,730	40,314,226	63,882,777						
708,780	2,025,080	2,733,860	24,979,440	11,203,706						
94,240	0	94,240	7,122,850	12,184,916						
539,190	439,310	978,500	5,966,600	7,873,275						
7,582,470	**7,030,000**	**14,612,470**	**131,196,786**	**144,395,481**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,384,820	616,070	17,091,580	3,373,550	11,525,020	35,740	1,212,870	12,773,630	23,466,020	36,239,650
ME	2,093,810	3,020,440	0	657,440	10,536,430	1,380	264,480	10,802,290	5,771,690	16,573,980
MA	1,761,630	929,100	5,597,860	12,129,930	18,721,980	28,096	1,145,610	19,895,686	20,418,540	40,314,226
NH	708,780	2,025,080	10,000,870	4,033,330	8,085,320	2,600	122,500	8,211,420	16,768,020	24,979,440
RI	94,240	0	0	0	7,028,610	0	0	7,028,610	94,240	7,122,850
VT	539,190	439,310	4,969,930	0	12,490	5,680	0	18,170	5,948,430	5,966,600
Total	**7,582,470**	**7,030,000**	**37,660,240**	**20,194,270**	**55,910,850**	**73,496**	**2,745,460**	**58,729,806**	**72,466,980**	**131,196,786**

Summary of Results: 2013 Current Trends Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM + T&D loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSE ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
72.0	69.7	58%	6,886	35,070,158	36,048,440	-978,268	8,032	8,251	-219	4.1	9.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,009	62	224	114	-163	-11	155	1,743

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,526	394	-3	-62	21	3	70	3,391	9.67	300	224	524	1.49	3,914	11.16

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,364	413	1,778	5.07	300	224	524	1.49	2,301	6.56

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.6%	2,721

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,972,371	17,170,853	82,685,196	32%	56,705,204	88,494,646	393,408,240

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,690,136	9,032	4,662	9,819,715	24,657	6,985
ME	6,404,295	4,242	1,765	6,405,452	4,680	1,874
MA	21,878,882	74,236	19,882	21,854,107	74,222	19,874
NH	7,823,480	25,571	6,951	7,826,905	25,572	6,952
RI	2,872,410	25	496	2,872,410	25	496
VT	552,226	1	1	557,427	1	2
Total	**49,221,428**	**113,106**	**33,757**	**49,336,107**	**129,157**	**36,183**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,170	615,720	3,000,890	36,048,150	35,070,158	13%	10%	3%	1,132,020	1,257,940	116,586,260
2,094,050	3,020,430	5,114,480	16,513,170	13,066,492						
1,761,600	903,030	2,664,630	39,801,440	63,882,777						
709,060	2,024,150	2,733,210	24,919,020	11,703,706						
94,230	0	94,230	6,856,900	12,184,916						
539,250	438,970	978,220	5,963,650	7,873,275						
7,583,360	**7,002,300**	**14,585,660**	**130,102,330**	**143,301,323**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,170	615,720	17,091,580	3,354,880	11,408,700	29,780	1,162,230	12,600,800	23,447,350	36,048,150
ME	2,094,050	3,020,430	0	657,570	10,491,710	1,210	258,200	10,741,120	5,772,050	16,513,170
MA	1,761,600	903,030	5,597,860	12,111,340	18,278,840	24,820	1,123,950	19,427,610	20,373,830	39,801,440
NH	709,060	2,024,150	10,000,870	4,027,580	8,051,540	1,930	103,890	8,157,360	16,761,660	24,919,020
RI	94,230	0	0	0	6,762,670	0	0	6,762,670	94,230	6,856,900
VT	539,250	438,970	4,969,930	0	12,290	3,210	0	15,500	5,948,150	5,963,650
Total	**7,583,360**	**7,002,300**	**37,660,240**	**20,151,370**	**54,955,840**	**60,950**	**2,648,270**	**57,705,060**	**72,397,270**	**130,102,330**

Summary of Results: 2018 Current Trends Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
78.6	75.9	57%	7,441	36,952,178	37,751,551	-799,366	8,677	8,550	127	3.1	10.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
28	323	42	1,123	148	324	143	-180	5	156	2,112

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,906	320	-11	-67	21	4	77	3,736	10.11	116	324	440	1.19	4,176	11.30

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,632	413	2,045	5.53	116	324	440	1.19	2,485	6.73

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.3%	2,510

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
14,825,016	20,059,989	97,714,790	36%	66,768,645	97,549,818	453,252,636

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,871,777	7,387	4,309	10,210,320	22,565	6,613
ME	7,813,164	3,958	1,953	7,814,468	4,394	2,062
MA	22,105,232	67,518	18,445	22,087,337	67,542	18,447
NH	7,871,126	26,990	7,274	7,874,248	26,954	7,264
RI	2,708,347	23	468	2,708,347	23	468
VT	511,265	1	2	516,989	2	3
Total	52,880,915	105,877	32,450	51,211,709	121,482	34,860

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,340	616,590	2,995,930	37,751,230	36,952,178	20%	17%	3%	1,211,280	1,172,860	222,159,494
2,011,340	3,020,530	5,031,870	20,128,500	13,807,015						
1,781,890	921,570	2,703,460	42,123,270	66,657,772						
697,470	2,926,170	3,623,640	24,665,340	12,047,803						
95,270	0	95,270	6,485,050	12,665,021						
494,600	439,700	934,300	6,027,740	8,272,715						
7,459,910	7,924,560	14,484,470	137,181,130	150,402,507						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,340	616,590	17,180,880	3,356,720	13,524,340	41,660	651,700	14,217,700	23,533,530	37,751,230
ME	2,011,340	3,020,530	0	666,230	14,252,710	1,340	176,350	14,430,400	5,698,100	20,128,500
MA	1,781,890	921,570	5,597,860	11,344,870	21,827,060	37,880	612,140	22,477,080	19,646,190	42,123,270
NH	697,470	2,926,170	10,000,870	4,317,890	7,602,050	3,210	17,680	7,622,940	17,042,400	24,665,340
RI	95,270	0	0	0	6,389,780	0	0	6,389,780	95,270	6,485,050
VT	494,600	439,700	5,074,090	0	13,940	5,410	0	19,350	6,008,390	6,027,740
Total	7,459,910	7,924,560	37,853,700	19,685,710	63,609,880	89,500	1,457,870	65,157,250	72,023,880	137,181,130

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.5	75.2	57%	6,790	34,173,972	35,589,118	-1,415,134	7,917	8,251	-334	3.3	10.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	993	136	299	104	-196	-13	303	1,982

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,650	310	-2	-67	21	3	75	3,439	10.06	172	299	472	1.38	3,911	11.44

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,380	413	1,793	5.25	172	299	472	1.38	2,264	6.63

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.1%	3,032

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,212,419	17,177,664	82,687,710	32%	62,830,362	93,252,893	432,967,129

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,002,542	7,366	4,145	9,313,418	22,501	6,446
ME	7,148,130	4,045	1,858	7,149,004	4,481	1,967
MA	22,323,530	67,788	18,540	22,304,171	67,803	18,540
NH	8,142,530	27,386	7,407	8,143,062	27,316	7,392
RI	2,717,219	23	469	2,717,218	23	469
VT	509,303	1	1	514,602	1	2
Total	51,843,253	106,609	32,420	50,141,476	122,126	34,817

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,340	616,230	2,995,570	35,588,810	34,173,972	20%	17%	3%	1,211,280	1,172,860	201,466,668
2,011,470	3,020,740	5,032,210	18,457,040	13,807,015						
1,781,920	923,660	2,705,580	42,603,670	66,657,772						
697,480	2,024,670	2,722,150	25,221,120	12,047,803						
95,330	0	95,330	6,506,800	12,665,021						
494,560	439,420	933,980	6,025,440	3,272,718						
7,460,100	7,024,720	14,484,820	134,402,880	147,624,301						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,340	616,230	17,180,880	3,374,900	11,389,760	31,920	615,780	12,037,460	23,551,350	35,588,810
ME	2,011,470	3,020,740	0	667,010	12,560,220	900	196,700	12,757,820	5,699,220	18,457,040
MA	1,781,920	923,660	5,597,860	11,352,250	22,245,340	28,860	673,540	22,947,980	19,655,690	42,603,670
NH	697,480	2,024,670	10,000,870	4,344,630	8,090,050	2,150	61,270	8,153,470	17,067,650	25,221,120
RI	95,330	0	0	0	6,411,470	0	0	6,411,470	95,330	6,506,800
VT	494,560	439,420	5,074,090	0	14,060	3,310	0	17,370	6,008,070	6,025,440
Total	7,460,100	7,024,720	37,853,700	19,738,790	60,711,140	67,140	1,547,290	63,325,570	72,077,310	134,402,880

Summary of Results: 2018 Current Trends Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.4	73.7	57%	7,441	36,952,178	44,825,452	-7,873,238	8,677	9,451	-774	3.6	10.4	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
583	437	53	1,062	132	324	22	-558	-33	156	2,179

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,858	370	-9	-81	24	3	73	3,726	10.08	116	324	440	1.19	4,166	11.27

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,699	413	2,113	5.72	116	324	440	1.19	2,552	6.91

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,410

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,750,563	16,804,772	79,798,717	25%	57,787,987	85,930,202	386,843,587

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,726,959	7,072	4,031	9,083,554	22,130	6,325
ME	6,213,591	4,018	1,692	6,215,424	4,454	1,802
MA	20,035,541	66,221	17,907	20,617,943	66,238	17,908
NH	8,059,254	26,964	7,299	8,058,513	26,878	7,280
RI	2,566,406	22	443	2,566,405	22	443
VT	510,073	1	1	515,346	2	2
Total	**48,711,733**	**104,298**	**31,374**	**47,057,186**	**119,724**	**33,761**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,180	616,100	2,995,280	44,825,060	36,952,178	20%	17%	3%	1,211,200	1,172,770	222,162,999
2,011,170	3,021,530	5,032,700	16,148,240	13,807,015						
1,781,770	944,080	2,729,850	38,913,400	66,657,772						
697,310	2,025,140	2,722,450	25,124,130	12,047,503						
95,260	0	95,260	6,148,220	12,665,021						
494,540	439,490	934,030	6,025,940	8,272,718						
7,459,230	**7,050,340**	**14,509,570**	**137,185,030**	**150,402,507**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,180	616,100	26,864,210	3,315,660	10,928,590	31,770	619,350	11,649,910	33,175,150	44,825,060
ME	2,011,170	3,021,530	0	657,700	10,252,040	1,490	203,470	10,457,140	5,690,400	16,148,240
MA	1,781,770	944,080	5,597,860	11,128,540	18,814,070	25,000	618,080	19,457,150	19,456,250	38,913,400
NH	697,310	2,025,140	10,000,870	4,270,750	8,060,800	2,550	66,710	8,130,060	16,994,070	25,124,130
RI	95,260	0	0	0	6,052,960	0	0	6,052,960	95,260	6,148,220
VT	494,540	439,490	5,074,090	0	13,860	4,000	0	17,860	6,008,120	6,025,980
Total	**7,459,230**	**7,050,340**	**47,537,030**	**19,372,650**	**54,192,360**	**65,210**	**1,508,210**	**55,765,780**	**81,419,250**	**137,185,030**

Summary of Results: 2018 Current Trends Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.4	73.7	57%	7,441	36,952,178	44,825,452	-7,873,238	8,677	9,451	-774	3.6	10.4	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
302	371	89	1,234	259	324	22	-558	-33	156	2,166

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spot	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,858	370	-9	-81	24	3	73	3,726	10.08	116	324	440	1.19	4,166	11.27

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,686	413	2,099	5.68	116	324	440	1.19	2,539	6.87

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,410

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,750,563	16,804,772	79,796,717	25%	57,787,987	85,930,202	386,843,587

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,860,481	7,072	4,031	17,217,166	22,130	6,325
ME	6,213,591	4,018	1,692	6,215,424	4,454	1,902
MA	20,635,541	66,221	17,907	20,617,943	66,238	17,908
NH	8,059,254	26,964	7,299	8,058,513	26,878	7,280
RI	2,566,406	22	443	2,566,405	22	443
VT	510,073	1	1	515,346	2	2
Total	**56,845,345**	**104,298**	**31,374**	**55,190,798**	**119,724**	**33,761**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,180	616,100	2,995,280	44,825,060	36,952,178	20%	17%	3%	1,211,200	1,172,770	222,162,999
2,011,170	3,021,530	5,032,700	16,148,240	13,807,015						
1,781,770	948,080	2,729,850	38,913,400	66,657,772						
697,310	2,025,140	2,722,450	25,124,130	12,047,805						
95,260	0	95,260	6,148,220	12,665,021						
494,540	439,490	934,030	6,025,980	8,272,718						
7,459,230	**7,050,340**	**14,509,570**	**137,185,030**	**150,402,507**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,180	616,100	17,180,880	12,611,657	10,998,590	31,270	619,550	11,649,910	32,787,817	44,437,727
ME	2,011,170	3,021,530	0	657,700	10,252,040	3,490	203,870	10,457,840	5,690,400	16,148,240
MA	1,781,770	948,080	5,597,860	11,128,540	18,814,070	25,000	618,080	19,457,150	19,456,250	38,913,400
NH	697,310	2,025,140	10,000,870	4,270,750	8,060,800	2,550	66,710	8,130,060	16,994,070	25,124,130
RI	95,260	0	0	0	6,052,960	0	0	6,052,960	95,260	6,148,220
VT	494,540	439,490	5,074,090	0	13,860	4,000	0	17,860	6,008,120	6,025,980
Total	**7,459,230**	**7,050,340**	**37,853,700**	**28,668,647**	**54,192,360**	**65,210**	**1,508,210**	**55,765,780**	**81,031,917**	**136,797,697**

Summary of Results: 2030 Current Trends Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
86.7	82.8	56%	8,424	41,549,275	50,226,725	-8,677,412	9,823	10,947	-1,124	4.3	9.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
244	392	73	1,942	368	319	19	-698	-52	156	2,757

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,604	510	-40	-72	16	9	68	4,709	11.33	116	319	435	1.05	5,143	12.38

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,283	413	2,696	6.49	116	319	435	1.05	3,131	7.53

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,771

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
29,403,944	40,105,707	189,023,414	53%	95,381,976	143,570,649	623,922,415

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,752,426	6,372	4,802	15,035,922	20,065	6,888
ME	9,396,131	3,605	2,158	9,397,718	4,141	2,270
MA	23,170,241	61,534	17,757	23,065,590	62,277	17,471
NH	7,476,317	26,114	7,014	7,479,512	26,030	6,997
RI	2,997,715	26	518	2,997,715	26	518
VT	1,428,394	12	147	1,433,535	13	148
Total	**61,221,224**	**99,753**	**32,395**	**59,409,391**	**112,552**	**34,291**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	617,700	3,141,350	50,226,470	41,549,275	23%	20%	3%	1,254,600	1,273,850	235,294,330
2,105,950	3,022,930	5,128,880	24,077,360	16,096,049						
1,761,170	913,200	2,674,370	45,918,748	76,092,263						
674,640	2,053,640	2,728,280	23,857,840	14,892,841						
90,730	0	90,730	7,237,680	14,346,939						
571,520	443,200	1,014,720	8,097,450	9,600,632						
7,727,660	**7,050,670**	**14,778,330**	**159,415,548**	**172,617,999**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,650	617,700	17,180,600	3,298,140	26,460,350	33,730	112,300	26,606,380	23,620,090	50,226,470
ME	2,105,950	3,022,930	0	700,160	18,176,280	1,600	70,440	18,248,320	5,829,040	24,077,360
MA	1,761,170	913,200	5,597,850	10,837,320	26,671,140	15,768	122,290	26,809,198	19,109,550	45,918,748
NH	674,640	2,053,640	9,912,880	4,195,820	7,012,600	8,260	0	7,020,860	16,836,980	23,857,840
RI	90,730	0	0	0	7,146,950	0	0	7,146,950	90,730	7,237,680
VT	571,520	443,200	5,014,570	0	2,053,490	14,670	0	2,068,160	6,029,290	8,097,450
Total	**7,727,660**	**7,050,670**	**37,705,910**	**19,031,440**	**87,520,810**	**74,028**	**305,030**	**87,899,868**	**71,515,680**	**159,415,548**

Summary of Results: 2030 Current Trends Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
85.6	82.4	57%	7,687	38,425,488	49,751,361	-11,325,831	8,963	10,647	-1,684	4.4	9.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	384	71	1,908	361	295	6	-906	-89	232	2,482

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,289	475	-15	-68	16	8	67	4,340	11.30	172	295	467	1.22	4,807	12.51

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,955	413	2,369	6.16	172	295	467	1.22	2,836	7.38

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.9%	4,400

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,591,941	34,915,589	185,448,816	52%	91,066,125	134,194,327	599,699,315

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,477,094	6,032	4,682	14,774,143	19,774	6,779
ME	9,329,153	3,685	2,144	9,331,329	4,132	2,256
MA	22,301,117	62,456	17,370	22,205,200	61,217	17,069
NH	7,432,014	25,888	6,956	7,434,232	25,781	6,934
RI	2,682,341	23	463	2,682,341	23	463
VT	1,424,150	13	146	1,429,267	14	148
Total	59,645,870	98,098	31,767	57,856,513	110,941	33,669

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	617,870	3,141,520	49,751,100	38,425,488	23%	20%	3%	1,254,600	1,273,850	214,458,531
2,105,910	3,023,580	5,129,490	23,918,520	16,096,049						
1,761,170	941,880	2,703,050	44,229,210	76,092,263						
674,640	2,056,180	2,730,820	23,807,640	14,892,841						
90,730	0	90,730	6,498,550	14,386,939						
571,520	443,520	1,015,040	8,084,900	9,600,632						
7,727,620	7,083,030	14,810,650	156,289,920	169,494,212						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,650	617,870	17,180,600	3,249,180	26,030,690	26,000	123,110	26,179,800	23,571,300	49,751,100
ME	2,105,910	3,023,580	0	700,590	18,018,420	2,200	67,820	18,088,440	5,830,080	23,918,520
MA	1,761,170	941,880	5,597,860	10,654,460	25,107,320	19,090	147,430	25,273,840	18,955,370	44,229,210
NH	674,640	2,056,180	9,912,880	4,155,630	6,998,420	9,890	0	7,008,310	16,799,330	23,807,640
RI	90,730	0	0	0	6,407,820	0	0	6,407,820	90,730	6,498,550
VT	571,520	443,520	5,014,570	0	2,039,340	15,950	0	2,055,290	6,029,610	8,084,900
Total	7,727,620	7,083,030	37,705,910	18,759,860	84,602,010	73,130	338,360	85,013,500	71,276,420	156,289,920

Summary of Results: 2030 Current Trends Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
84.1	79.5	56%	8,424	41,549,275	57,195,648	-15,646,330	9,823	11,847	-2,024	5.0	9.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL GOING-FORWARD RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
803	507	83	1,363	336	319	1	-1,194	-122	156	2,751

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,493	593	-40	-85	15	12	63	4,659	11.21	116	319	435	1.05	5,094	12.26

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,276	413	2,690	6.47	116	319	435	1.05	3,124	7.52

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	4,670

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,218,583	36,558,105	170,059,081	42%	83,771,422	130,686,765	554,643,325

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	15,360,496	5,758	4,427	13,790,048	19,210	6,487
ME	9,255,887	3,659	2,126	9,258,325	4,106	2,238
MA	21,650,807	62,031	17,167	21,568,694	60,868	16,904
NH	7,370,588	25,874	6,943	7,374,396	25,791	6,926
RI	2,491,206	22	430	2,491,206	22	430
VT	600,282	5	4	605,201	6	5
Total	56,739,266	97,348	31,097	55,087,870	110,003	32,990

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,200	617,350	3,125,550	57,195,380	41,549,275	23%	20%	3%	1,244,920	1,268,070	235,617,160
2,105,900	3,023,090	5,128,990	23,739,510	16,096,049						
1,761,160	894,330	2,655,490	42,723,320	76,092,263						
674,640	2,053,140	2,727,780	23,657,940	14,892,841						
90,680	0	90,680	6,042,880	14,386,939						
571,480	443,590	1,015,070	6,055,680	9,600,632						
7,712,060	7,031,500	14,743,540	159,414,710	172,617,999						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,200	617,350	26,863,930	3,173,880	23,898,660	35,230	98,130	24,032,020	33,163,360	57,195,380
ME	2,105,900	3,023,090	0	695,210	17,844,630	2,460	67,220	17,914,310	5,825,200	23,739,510
MA	1,761,160	894,330	5,597,860	10,599,390	23,718,200	18,920	133,760	23,870,580	18,852,740	42,723,320
NH	674,640	2,053,140	9,912,880	4,155,700	6,852,750	8,830	0	6,861,580	16,796,360	23,657,940
RI	90,680	0	0	0	5,952,200	0	0	5,952,200	90,680	6,042,880
VT	571,480	443,590	5,014,570	0	11,860	14,180	0	26,040	6,029,640	6,055,680
Total	7,712,060	7,031,500	47,389,240	18,625,180	78,278,300	79,320	299,110	78,656,730	80,757,980	159,414,710

Summary of Results: 2030 Current Trends Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
84.1	79.5	56%	8,424	41,549,275	57,195,648	-15,646,330	9,823	11,847	-2,024	5.0	9.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
522	441	119	2,037	556	319	1	-1,194	-122	156	2,834

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,493	593	-40	-85	15	12	63	4,659	11.21	116	319	435	1.05	5,094	12.26

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,359	413	2,772	6.67	116	319	435	1.05	3,207	7.72

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	4,670

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,218,583	36,558,105	170,059,061	42%	83,771,422	130,686,765	554,643,325

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	23,494,109	5,758	4,427	21,923,661	19,210	6,487
ME	9,255,887	3,659	2,126	9,258,325	4,106	2,234
MA	21,660,807	62,031	17,167	21,568,694	60,868	16,904
NH	7,370,588	25,874	6,943	7,374,396	25,791	6,936
RI	2,491,206	22	430	2,491,206	22	430
VT	600,282	5	4	605,201	6	5
Total	**64,872,878**	**97,348**	**31,097**	**63,221,482**	**110,003**	**32,996**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,200	617,350	3,125,550	57,195,380	41,549,275	23%	20%	3%	1,244,920	1,268,070	235,617,160
2,105,900	3,023,090	5,128,990	23,739,510	16,096,049						
1,761,160	894,330	2,655,490	42,723,320	76,092,263						
674,640	2,053,140	2,727,780	23,657,940	14,892,841						
90,680	0	90,680	6,042,880	14,366,939						
571,480	443,590	1,015,070	6,055,680	9,600,632						
7,712,060	**7,031,500**	**14,743,560**	**159,414,710**	**172,617,999**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,200	617,350	17,180,600	12,469,877	23,898,660	35,230	98,130	24,032,020	32,776,027	56,808,047
ME	2,105,900	3,023,090	0	696,210	17,444,630	2,460	67,220	17,914,310	5,925,200	23,739,510
MA	1,761,160	894,330	5,597,860	10,599,390	23,718,200	18,920	133,760	23,870,580	18,852,740	42,723,320
NH	674,640	2,053,140	9,912,880	4,155,700	6,825,750	8,930	0	6,861,580	16,796,360	23,657,940
RI	90,680	0	0	0	5,952,200	0	0	5,952,200	90,680	6,042,880
VT	571,480	443,590	5,014,570	0	11,860	14,180	0	26,040	6,029,640	6,055,680
Total	**7,712,060**	**7,031,500**	**37,705,910**	**27,921,177**	**78,278,100**	**79,720**	**299,110**	**78,656,730**	**80,370,647**	**159,027,377**

Summary of Results: 2011 Strict Climate Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
81.6	78.4	57%	7,061	35,287,973	36,291,706	-1,003,716	8,233	8,251	-18	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,120	62	199	162	-203	-1	76	1,767

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,880	445	-7	-70	28	4	67	3,848	10.90	123	199	322	0.91	4,170	11.82

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,492	413	1,905	5.40	123	199	322	0.91	2,227	6.31

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
22.1%	2,213

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,297,896	16,440,405	77,350,274	30%	48,466,931	82,678,365	353,195,084

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,094,871	12,328	5,537	10,205,368	28,859	7,980
ME	5,953,600	3,896	1,626	5,963,605	4,275	1,724
MA	21,293,052	77,268	20,453	21,370,749	77,379	20,451
NH	7,543,581	25,005	6,779	7,546,712	25,006	6,780
RI	2,404,712	21	415	2,404,712	21	415
VT	602,613	2	2	609,628	2	2
Total	47,902,429	118,569	34,812	48,000,773	135,442	37,352

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,570	615,550	3,123,120	36,291,410	35,287,973	11%	8%	3%	1,275,100	1,257,260	79,522,367
1,957,990	3,020,430	4,978,420	15,591,556	12,454,988						
1,644,550	917,550	2,602,100	37,829,259	61,570,447						
678,320	2,024,640	2,702,960	24,351,100	10,614,392						
92,870	0	92,870	5,766,270	11,731,213						
587,840	438,910	1,026,750	6,115,520	7,528,882						
7,509,140	7,017,080	14,526,220	125,945,114	139,187,895						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,570	615,550	17,201,880	3,951,830	10,721,360	13,260	1,279,960	12,014,580	24,276,830	36,291,410
ME	1,957,990	3,020,430	0	582,630	9,770,930	6	259,570	10,030,505	5,561,050	15,591,556
MA	1,644,550	917,550	5,597,860	12,507,930	15,776,019	4,360	1,340,990	17,121,369	20,707,890	37,829,259
NH	678,320	2,024,640	10,000,870	3,932,930	7,601,450	1,940	110,950	7,714,340	16,636,760	24,351,100
RI	92,870	0	0	0	5,673,400	0	0	5,673,400	92,870	5,766,270
VT	587,840	438,910	5,074,090	0	10,460	4,220	0	14,680	6,100,840	6,115,520
Total	7,509,140	7,017,080	37,874,700	20,975,320	49,553,619	23,786	2,991,470	52,568,874	73,376,240	125,945,114

Summary of Results: 2011 Strict Climate Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.06 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
81.3	78.2	58%	6,899	34,885,917	36,261,874	-1,375,936	8,644	8,251	-206	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,117	62	197	144	-216	-11	94	1,739

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,838	434	-6	-69	27	4	67	3,788	10.86	220	197	417	1.20	4,205	12.05

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,447	413	1,861	5.33	220	197	417	1.20	2,278	6.53

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
22.8%	2,429

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,152,447	16,428,066	77,213,673	30%	48,378,189	82,431,741	351,524,518

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,083,099	12,322	5,527	10,190,357	28,839	7,974
ME	5,942,814	3,791	1,600	5,942,827	4,170	1,698
MA	21,146,697	76,917	20,353	21,123,091	76,924	20,350
NH	7,530,843	24,975	6,770	7,533,921	24,975	6,771
RI	2,392,894	21	413	2,392,894	21	413
VT	602,573	2	2	609,635	2	2
Total	**47,698,919**	**118,017**	**34,665**	**47,792,726**	**134,932**	**37,207**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,410	615,540	3,122,950	36,261,600	34,885,917	11%	8%	3%	1,274,910	1,237,290	77,879,739
1,958,040	3,020,750	4,978,790	15,571,740	12,454,984						
1,684,450	870,320	2,554,770	37,527,625	61,570,447						
678,240	2,024,700	2,702,940	24,328,610	10,614,392						
92,860	0	92,860	5,742,740	11,731,213						
587,750	438,940	1,026,690	6,115,634	7,528,882						
7,508,750	**6,970,250**	**14,479,000**	**125,547,949**	**138,785,838**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,507,410	615,540	17,201,880	3,956,270	10,700,950	11,410	1,268,140	11,980,500	24,281,100	36,261,600
ME	1,958,040	3,020,750	0	583,240	9,775,930	10	233,770	10,009,710	5,562,030	15,571,740
MA	1,684,450	870,320	5,597,860	12,502,110	15,607,945	3,490	1,261,450	16,872,885	20,654,740	37,527,625
NH	678,240	2,024,700	10,000,870	3,931,390	7,585,370	1,890	106,150	7,693,410	16,635,200	24,328,610
RI	92,860	0	0	0	5,649,880	0	0	5,649,880	92,860	5,742,740
VT	587,750	438,940	5,074,090	0	10,600	4,254	0	14,854	6,100,760	6,115,634
Total	**7,508,750**	**6,970,250**	**37,874,700**	**20,973,010**	**49,330,675**	**21,054**	**2,869,510**	**52,221,239**	**73,326,710**	**125,547,949**

Summary of Results: 2013 Strict Climate Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEr ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
87.6	84.5	56%	7,187	35,522,074	35,737,361	-215,288	8,380	8,251	129	2.4	11.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	38	1,054	237	227	182	-169	4	103	1,990

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM ($Mil)	AVERAGE GENERATION SVC COST + 15% PREMIUM (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	TOTAL SYSTEM BENEFITS COST ($Mil)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($Mil)	AVG COST (¢/kWh)
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)								
3,110	237	-4	-76	24	3	82	3,883	10.93	121	227	348	0.98	4,231	11.91

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,660	413	2,074	5.84	121	227	348	0.98	2,422	6.82

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.1%	2,378

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,675,121	17,368,134	83,646,098	32%	57,657,821	90,106,227	400,253,976

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	11,112,968	6,923	4,109	9,446,287	22,341	6,411
ME	6,373,569	4,040	1,715	6,375,627	4,478	1,825
MA	19,999,797	62,010	16,854	19,994,130	62,036	16,869
NH	7,213,902	21,882	6,032	7,220,031	21,884	6,034
RI	2,985,374	26	516	2,985,374	26	516
VT	553,503	1	1	560,093	2	3
Total	**48,239,114**	**94,881**	**29,237**	**46,581,541**	**110,768**	**31,657**

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,385,430	616,770	3,002,200	35,737,050	35,522,074	13%	10%	3%	1,132,160	1,258,070	118,797,798
2,094,210	3,020,750	5,114,960	16,496,370	12,747,271						
1,761,770	1,004,340	2,766,150	38,466,275	62,513,186						
709,130	2,025,980	2,735,110	24,386,530	10,963,724						
94,240	0	94,240	7,118,770	11,950,422						
539,300	439,660	978,960	5,967,710	7,672,083						
7,584,080	**7,107,540**	**14,691,620**	**128,172,705**	**141,366,760**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,385,430	616,770	17,091,580	3,027,940	11,458,880	37,750	1,118,700	12,615,330	23,121,720	35,737,050
ME	2,094,210	3,020,750	0	639,240	10,506,990	2,150	233,030	10,742,170	5,754,200	16,496,370
MA	1,761,770	1,004,340	5,597,860	10,280,290	18,856,000	35,525	930,450	19,821,975	18,644,300	38,466,275
NH	709,130	2,025,980	10,000,870	3,447,260	8,092,030	4,380	106,880	8,203,290	16,183,240	24,386,530
RI	94,240	0	0	0	7,024,530	0	0	7,024,530	94,240	7,118,770
VT	539,300	439,660	4,969,930	0	14,290	4,530	0	18,820	5,948,890	5,967,710
Total	**7,584,080**	**7,107,540**	**37,660,240**	**17,394,730**	**55,951,720**	**84,335**	**2,389,060**	**58,426,115**	**69,746,590**	**128,172,705**

Summary of Results: 2013 Strict Climate Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
86 6	83 7	57%	6,871	34,429,862	35,479,485	-1,049,607	8,011	8,251	-240	2 9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	1,036	232	220	141	-203	-3	155	1,923

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,983	280	-3	-73	23	4	78	3,786	11.00	300	220	519	1.51	4,305	12.50

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,549	413	1,962	5.70	300	220	519	1.51	2,481	7.21

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
20.4%	2,807

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,488,297	17,144,988	81,884,585	32%	56,195,381	88,874,956	393,555,334

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,918,030	6,542	3,970	9,261,310	21,774	6,257
ME	6,309,421	3,955	1,686	6,311,280	4,394	1,796
MA	19,751,754	61,529	16,716	19,744,632	61,549	16,719
NH	7,172,654	21,779	6,003	7,177,832	21,780	6,604
RI	2,892,664	25	500	2,892,664	25	500
VT	552,469	0	1	558,513	1	2
Total	**47,596,993**	**93,830**	**28,875**	**45,946,233**	**109,524**	**31,278**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,384,990	616,340	3,001,330	35,479,170	34,429,862	13%	10%	3%	1,131,940	1,257,840	113,447,033
2,093,930	3,020,030	5,113,960	16,361,570	12,747,271						
1,761,500	1,032,490	2,793,990	38,044,980	62,513,186						
708,990	2,024,380	2,733,370	24,311,610	10,901,724						
94,240	0	94,240	6,908,530	11,950,422						
539,190	439,350	978,540	5,965,640	7,672,083						
7,582,840	**7,132,590**	**14,715,430**	**127,071,500**	**140,274,548**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,384,990	616,340	17,091,580	2,993,680	11,322,590	31,130	1,038,860	12,392,580	23,086,590	35,479,170
ME	2,093,930	3,020,030	0	635,660	10,392,140	1,940	217,870	10,611,950	5,749,620	16,361,570
MA	1,761,500	1,032,490	5,597,860	10,203,220	18,495,350	28,840	925,720	19,449,910	18,595,070	38,044,980
NH	708,990	2,024,380	10,000,870	3,438,880	8,039,670	3,690	95,130	8,138,490	16,173,120	24,311,610
RI	94,240	0	0	0	6,814,290	0	0	6,814,290	94,240	6,908,530
VT	539,190	439,350	4,969,930	0	13,650	3,520	0	17,170	5,948,470	5,965,640
Total	**7,582,840**	**7,132,590**	**37,660,240**	**17,271,440**	**55,077,690**	**69,120**	**2,277,580**	**57,424,390**	**69,647,110**	**127,071,500**

Summary of Results: 2018 Strict Climate Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.04 load grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSE ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.3	88.0	56%	7,381	35,980,213	37,365,682	-1,385,459	8,606	8,550	56	2.8	11.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
28	323	41	1,170	302	315	151	-239	2	156	2,250

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Over-counting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,287	286	-9	-76	22	4	79	4,132	11.48	116	315	431	1.20	4,563	12.68

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,779	413	2,192	6.09	116	315	431	1.20	2,623	7.29

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.8%	2,640

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
14,234,387	19,931,247	96,239,386	36%	62,884,236	95,562,172	441,165,588

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	11,486,141	5,473	3,805	9,837,973	20,849	6,168
ME	7,037,219	3,823	1,790	7,038,379	4,259	1,899
MA	20,351,916	57,439	15,920	20,366,662	57,478	15,930
NH	6,991,151	21,014	5,802	6,998,931	21,015	5,804
RI	2,731,082	24	472	2,731,082	24	472
VT	508,874	0	1	516,049	2	2
Total	49,116,382	87,773	27,791	47,489,076	103,626	30,276

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement (%)	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,379,560	616,940	2,996,500	37,365,400	35,980,213	20%	17%	3%	1,211,390	1,172,970	214,915,216
2,011,630	3,021,810	5,033,440	18,239,770	13,300,363						
1,782,070	954,900	2,736,970	40,518,460	64,675,456						
697,550	2,026,720	2,724,270	24,047,420	11,683,543						
95,340	0	95,340	6,535,510	12,333,051						
494,600	440,050	934,650	6,027,710	7,972,790						
7,460,750	7,060,420	14,521,170	132,734,270	145,950,416						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,560	616,940	17,180,880	3,071,690	13,376,310	39,650	700,370	14,116,330	23,249,070	37,365,400
ME	2,011,630	3,021,810	0	628,170	12,382,770	1,220	194,170	12,578,160	5,661,610	18,239,770
MA	1,782,070	954,900	5,597,860	9,728,580	21,822,430	37,190	595,430	22,455,050	18,063,410	40,518,460
NH	697,550	2,026,720	10,000,870	3,339,850	7,913,240	3,520	65,670	7,982,430	16,064,990	24,047,420
RI	95,340	0	0	0	6,440,170	0	0	6,440,170	95,340	6,535,510
VT	494,600	440,050	5,074,090	0	14,800	4,170	0	18,970	6,008,740	6,027,710
Total	7,460,750	7,060,420	37,853,700	16,768,290	61,949,720	85,750	1,555,640	63,591,110	69,143,160	132,734,270

Summary of Results: 2018 Strict Climate Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * (08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91 8	88 8	56%	6,782	33,205,201	35,556,826	-2,351,606	7,908	8,251	-343	2 2	11 8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	;$Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	1,061	261	291	96	-284	-9	303	2,090

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	(SMil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,048	204	-3	-76	24	3	83	3,776	11.37	172	291	463	1.39	4,239	12.77

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,496	413	1,909	5.75	172	291	463	1.39	2,372	7.14

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17 1%	3,162

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,246,736	17,107,236	83,350,578	32%	59,050,149	90,942,649	418,068,811

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,845,368	5,723	3,752	9,149,445	21,162	6,119
ME	6,322,467	3,998	1,707	6,330,734	4,435	1,816
MA	20,438,209	59,109	16,300	20,440,942	59,149	16,309
NH	7,410,316	22,495	6,200	7,419,119	22,497	6,202
RI	2,951,131	25	510	2,951,131	25	510
VT	509,261	1	1	517,219	2	3
Total	**48,481,752**	**91,352**	**28,469**	**46,808,590**	**107,270**	**30,959**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,520	617,070	2,996,590	35,556,510	33,205,201	20%	17%	3%	1,211,360	1,172,960	194,247,501
2,011,480	3,022,870	5,034,350	16,439,110	13,300,363						
1,782,000	939,370	2,721,370	40,187,230	64,675,456						
697,410	2,028,250	2,725,660	24,692,390	11,668,543						
95,290	0	95,290	7,049,430	12,333,051						
494,560	440,280	934,840	6,029,480	7,972,790						
7,460,260	**7,047,840**	**14,508,100**	**129,954,150**	**143,175,404**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,520	617,070	17,180,880	3,099,580	11,513,940	36,900	728,620	12,279,460	23,277,050	35,556,510
ME	2,011,480	3,022,870	0	639,200	10,539,620	3,330	222,610	10,765,560	5,673,550	16,439,110
MA	1,782,000	939,370	5,597,860	9,953,760	21,196,070	39,660	678,510	21,914,240	18,272,990	40,187,230
NH	697,410	2,028,250	10,000,870	3,555,840	8,307,460	5,110	97,050	8,410,020	16,282,370	24,692,390
RI	95,290	0	0	0	6,954,140	0	0	6,954,140	95,290	7,049,430
VT	494,560	440,280	5,074,090	0	15,850	4,700	0	20,550	6,008,930	6,029,480
Total	**7,460,260**	**7,047,840**	**37,853,700**	**17,248,380**	**58,527,080**	**89,700**	**1,726,790**	**60,343,970**	**69,610,180**	**129,954,150**

Summary of Results: 2018 Strict Climate Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Total Energy Needed to Meet Customer Load (MWh)	Total Generation In Connecticut (MWh)	Net Imports (MWh)	CT LSEs' ICR (MW)	CT Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)	Fast-Start Price ($/kW-Mo)	Fast-Start Requirement (MW)
91.0	86.6	56%	7,381	35,980,213	44,542,256	-8,562,015	8,606	9,451	-845	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	CT Energy Import Cost ($Mil)	CT Energy Export Cost ($Mil)	CT Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	TOTAL RESOURCE COST ($Mil)
583	437	52	1,107	269	315	20	-707	-30	156	2,204

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP ($Mil)	ICR*Price ($Mil)	FTRs (Assume 75% Coverage for Internal Gen to Load) ($Mil)	Adjustment for Overcounting Losses ($Mil)	Spot ($Mil)	Uplift ($Mil)	Connecticut Fast-Start Cost ($Mil)	TOTAL GENERATION SVC COST + 15% PREMIUM ($Mil)	AVERAGE GENERATION SVC COST + 15% PREMIUM (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	TOTAL SYSTEM BENEFITS COST ($Mil)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($Mil)	AVG COST (¢/kWh)
3,274	301	-8	-92	25	4	78	4,119	11.45	116	315	431	1.20	4,550	12.65

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS ($Mil)	Annualized Embedded Cost of Generators ($Mil)	TOTAL GENERATION SVC COST ($Mil)	AVERAGE GENERATION SVC COST (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	TOTAL SYSTEM BENEFITS COST ($Mil)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($Mil)	AVG COST (¢/kWh)
1,732	413	2,144	5.96	116	315	431	1.20	2,577	7.16

Electric Reliability and Availability

ISO-NE Reserve Margin (%)	CT LSR Surplus (Deficit) (MW)
17.8%	3,541

Fuel Security

CT NG Demand in January and February (MMBtu)	CT NG Demand in July and August	Total CT NG Demand (MMBtu)	CT NG Share of Total CT Generation (%)	ISO-NE NG Demand in January and February (MMBtu)	ISO NG Demand in July and August	Total ISO-NE NG Demand (MMBtu)
11,533,870	16,816,017	78,986,941	24%	54,317,618	83,869,991	375,380,717

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	10,412,733	5,479	3,616	8,795,803	20,644	5,945
ME	6,139,164	3,779	1,627	6,141,637	4,215	1,736
MA	18,335,491	56,365	15,339	18,336,893	56,401	15,347
NH	6,947,261	20,569	5,696	6,954,744	20,571	5,698
RI	2,639,368	23	456	2,639,368	23	456
VT	508,361	0	1	515,636	2	2
Total	44,982,381	86,215	26,734	43,384,082	101,855	29,184

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,379,130	616,490	2,995,620	44,541,930	35,980,213	20%	17%	3%	1,211,090	1,172,830	214,928,360
2,011,300	3,022,340	5,033,640	16,023,090	13,300,363						
1,781,860	934,440	2,716,300	35,774,810	64,675,456						
697,260	2,026,900	2,724,160	24,049,090	11,668,543						
95,320	0	95,320	6,320,240	12,333,051						
494,490	439,760	934,250	6,027,200	7,972,790						
7,459,360	7,039,930	14,499,290	132,736,360	145,950,416						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,130	616,490	26,864,210	3,038,860	10,909,520	36,050	697,670	11,643,240	32,898,690	44,541,930
ME	2,011,300	3,022,340	0	609,520	10,164,570	2,590	208,770	10,379,930	5,643,160	16,023,090
MA	1,781,860	934,440	5,597,860	9,576,540	17,308,680	31,630	543,800	17,884,110	17,890,700	35,774,810
NH	697,260	2,026,900	10,000,870	2,255,320	7,981,740	4,010	82,990	8,068,740	15,980,350	24,049,090
RI	95,320	0	0	0	6,224,920	0	0	6,224,920	95,320	6,320,240
VT	494,490	439,760	5,074,090	0	15,100	3,760	0	18,860	6,008,340	6,027,200
Total	7,459,360	7,039,930	47,537,030	16,480,240	52,608,530	78,040	1,533,230	54,219,800	78,516,560	132,736,360

Summary of Results: 2018 Strict Climate Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.0	86.6	56%	7,381	35,980,213	44,542,266	-8,562,015	8,606	9,451	-845	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
302	371	83	1,284	548	315	20	-707	-30	156	2,348

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM ($Mil)	AVERAGE GENERATION SVC COST + 15% PREMIUM (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	TOTAL SYSTEM BENEFITS COST ($Mil)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($Mil)	AVG COST (¢/kWh)
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)								
3,274	301	-8	-92	25	4	78	4,119	11.45	116	315	431	1.20	4,550	12.65

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,877	413	2,290	6.36	116	315	431	1.20	2,721	7.56

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.8%	3,541

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,533,870	16,816,017	78,886,941	25%	54,317,618	83,869,991	375,530,717

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,546,345	5,479	3,616	16,929,415	20,644	5,945
ME	6,139,168	3,779	1,627	6,141,637	4,215	1,736
MA	18,335,491	56,365	15,339	18,336,893	56,401	15,347
NH	6,947,561	20,569	5,696	6,954,744	20,571	5,698
RI	2,639,368	23	456	2,639,368	23	456
VT	508,561	0	1	515,636	2	2
Total	**53,115,994**	**86,215**	**26,734**	**51,517,694**	**101,855**	**29,184**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,130	616,490	2,995,620	44,541,930	35,980,213	20%	17%	3%	1,211,090	1,172,830	214,928,360
2,011,300	3,022,340	5,033,640	16,023,090	13,300,363						
1,781,460	934,440	2,716,300	35,774,810	64,675,456						
697,260	2,026,900	2,724,160	24,049,090	11,648,543						
95,320	0	95,320	6,320,240	12,333,051						
494,490	439,760	934,250	6,027,200	7,972,790						
7,459,360	**7,039,930**	**14,499,290**	**132,736,360**	**145,950,416**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,130	616,490	17,180,880	12,334,857	10,909,520	36,050	697,670	11,643,240	32,511,357	44,154,597
ME	2,011,300	3,022,340	0	609,520	10,168,370	2,590	208,770	10,379,930	5,643,160	16,023,090
MA	1,781,460	934,440	5,597,840	9,576,540	17,308,680	31,630	543,800	17,884,110	17,890,700	35,774,810
NH	697,260	2,026,900	10,000,870	3,255,320	7,981,740	4,010	82,990	8,068,740	15,980,350	24,049,090
RI	95,320	0	0	0	6,224,920	0	0	6,224,920	95,320	6,320,240
VT	494,490	439,760	5,074,090	0	15,100	3,760	0	18,860	6,008,340	6,027,200
Total	**7,459,360**	**7,039,930**	**37,853,700**	**25,776,237**	**52,608,330**	**78,040**	**1,533,230**	**54,219,800**	**78,129,227**	**132,349,027**

Summary of Results: 2030 Strict Climate Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
107.6	102.5	55%	8,355	40,456,272	49,918,087	-9,461,776	9,742	10,647	-904	3.0	11.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	384	72	2,030	777	310	25	-929	-33	156	3,043

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,352	351	-40	-86	18	11	77	5,386	13.31	116	310	426	1.05	5,812	14.37

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
2,596	413	3,010	7.44	116	310	426	1.05		3,436	8.49

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	3,619

Fuel Security

CT NG Demand in January and Febtuary	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
29,038,185	37,541,948	188,385,766	53%	91,373,474	140,264,997	633,427,818

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,220,265	3,745	4,048	14,538,105	17,066	6,133
ME	9,277,973	2,274	1,824	9,282,933	2,721	1,937
MA	19,437,874	38,762	11,647	19,449,033	38,822	11,662
NH	4,667,918	9,101	2,775	4,683,958	9,106	2,779
RI	3,177,354	27	549	3,177,354	27	549
VT	1,437,845	12	148	1,449,383	14	151
Total	**54,219,229**	**53,921**	**20,991**	**52,579,766**	**67,757**	**23,211**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,640	621,430	3,145,070	49,917,740	40,456,272	23%	20%	3%	1,254,600	1,273,850	228,003,953
2,105,920	3,028,300	5,134,220	24,132,630	15,506,927						
1,761,150	1,107,820	2,868,970	43,112,350	23,831,318						
674,630	2,058,510	2,733,140	21,331,200	14,450,182						
90,720	0	90,720	7,661,610	14,013,464						
571,520	445,740	1,017,260	8,131,440	9,246,022						
7,727,580	**7,261,800**	**14,989,380**	**154,287,010**	**167,504,187**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,523,640	621,430	17,180,600	2,640,620	26,534,140	44,850	332,260	26,911,450	23,006,290	49,917,740
ME	2,105,920	3,028,300	0	443,040	18,487,590	5,040	62,700	18,555,370	5,577,260	24,132,630
MA	1,761,150	1,107,820	5,597,860	6,648,020	27,561,870	27,290	408,380	27,997,540	15,114,850	43,112,390
NH	674,630	2,058,510	9,912,880	1,454,910	7,205,090	11,530	13,650	7,230,270	14,100,930	21,331,200
RI	90,720	0	0	0	7,570,890	0	0	7,570,890	90,720	7,661,610
VT	571,520	445,740	5,014,570	0	2,084,440	15,170	0	2,099,610	6,031,830	8,131,440
Total	**7,727,580**	**7,261,800**	**37,705,910**	**11,226,590**	**89,444,220**	**103,920**	**816,990**	**90,365,130**	**63,921,880**	**154,287,010**

Summary of Results: 2030 Strict Climate Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
106.7	102.6	56%	7,678	37,335,975	49,950,425	-12,614,407	8,953	10,647	-1,694	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	364	72	2,078	782	286	6	-1,248	-59	232	2,754

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,983	312	-16	-80	19	10	78	4,952	13.26	172	286	459	1.23	5,410	14.49

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,236	413	2,649	7.10	172	286	459	1.23	3,108	8.32

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.3%	4,548

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,770,447	37,521,315	187,820,624	53%	87,210,667	134,429,956	609,862,626

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,289,013	3,860	4,122	14,618,355	17,717	6,290
ME	9,348,329	2,375	1,958	9,352,741	2,823	1,971
MA	19,479,959	34,783	11,657	19,494,983	38,854	11,675
NH	4,810,226	9,524	2,892	4,827,003	9,529	2,897
RI	2,528,889	22	437	2,528,889	22	437
VT	600,244	4	3	611,055	7	6
Total	**53,056,660**	**54,568**	**20,970**	**51,433,027**	**68,950**	**23,275**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	621,640	3,145,290	49,950,120	37,335,975	23%	20%	3%	1,254,600	1,273,860	207,191,432
2,105,950	3,029,610	5,135,560	24,283,810	15,506,927						
1,761,170	1,101,630	2,862,800	43,235,610	73,831,318						
674,640	2,059,010	2,733,650	21,573,090	14,456,182						
90,730	0	90,730	6,052,710	14,013,464						
571,520	446,010	1,017,530	6,065,895	9,246,022						
7,727,660	**7,257,900**	**14,985,560**	**151,161,235**	**164,383,889**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,523,650	621,640	17,180,600	2,764,730	26,445,890	38,850	374,760	26,859,500	23,090,620	49,950,120
ME	2,105,950	3,029,610	0	462,840	18,619,260	4,490	61,660	18,685,410	5,598,400	24,283,810
MA	1,761,170	1,101,630	5,597,840	6,610,350	27,075,910	28,760	450,930	28,154,600	15,071,010	43,235,610
NH	674,640	2,059,010	9,912,880	1,522,900	7,370,450	11,850	12,360	7,403,660	14,169,430	21,573,090
RI	90,730	0	0	0	5,961,980	0	0	5,961,980	90,730	6,052,710
VT	571,520	446,010	5,014,570	0	18,610	15,185	0	33,795	6,032,100	6,065,895
Total	**7,727,660**	**7,257,900**	**37,705,910**	**11,360,820**	**86,101,100**	**99,135**	**908,710**	**87,108,945**	**64,052,290**	**151,161,235**

Summary of Results: 2030 Strict Climate Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.04 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
104.5	99.0	55%	5,355	40,456,272	55,252,527	-14,796,212	9,742	11,547	-1,804	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
776	459	79	1,836	674	310	1	-1,395	-90	156	2,894

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,227	487	-35	-103	17	14	69	5,377	13.29	116	310	426	1.05	5,804	14.35

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,428	413	2,841	7.02	116	310	426	1.05	3,268	8.08

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	4,518

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
24,690,535	32,403,356	158,826,885	40%	80,808,780	127,742,070	569,031,090

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	14,214,658	3,471	3,631	12,671,167	16,233	5,632
ME	8,419,439	2,490	1,724	8,422,906	2,937	1,836
MA	18,083,041	36,978	11,021	18,096,120	37,044	11,037
NH	4,719,654	9,472	2,865	4,737,201	9,477	2,870
RI	2,419,681	21	418	2,419,681	21	418
VT	2,161,019	23	274	2,172,375	25	277
Total	50,017,492	52,455	18,933	48,519,449	65,738	22,071

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,160	619,010	3,126,170	55,252,240	40,456,272	23%	20%	3%	1,244,420	1,267,540	228,343,458
2,105,350	3,026,340	5,131,690	21,945,690	15,506,927						
1,760,690	908,910	2,669,600	40,040,850	73,831,318						
674,410	2,065,640	2,740,050	21,368,140	14,450,182						
90,660	0	90,660	5,792,400	14,013,464						
571,310	444,960	1,016,270	9,894,914	9,246,022						
7,709,580	7,064,860	14,774,440	154,294,234	167,504,187						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,160	619,010	26,863,930	2,569,980	22,159,070	37,440	295,650	22,692,160	32,560,080	55,252,240
ME	2,105,350	3,026,340	0	455,500	16,255,670	3,540	99,290	16,358,500	5,587,190	21,945,690
MA	1,760,690	908,910	5,597,860	6,323,580	24,998,400	26,360	425,050	25,449,810	14,591,040	40,040,850
NH	674,410	2,065,640	9,912,880	1,504,850	7,171,330	12,410	26,620	7,210,360	14,157,780	21,368,140
RI	90,660	0	0	0	5,701,740	0	0	5,701,740	90,660	5,792,400
VT	571,310	444,960	5,014,570	0	3,837,130	26,944	0	3,864,074	6,030,840	9,894,914
Total	7,709,580	7,064,860	47,389,240	10,853,910	80,323,340	106,694	846,610	81,276,644	73,017,590	154,294,234

Summary of Results: 2030 Strict Climate Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	($/MW)	($/kW-Mo)	($/kW-Mo)	(MW)
104 5	99 0	55%	6,355	40,456,272	55,252,527	-14,796,212	9,742	11,547	-1,804	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
494	432	115	2,068	1,160	310	1	-1,395	-90	156	3,252

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spot	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,227	487	-35	-103	17	14	69	5,377	13.29	116	310	426	1.05	5,804	14.35

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,785	413	3,198	7.91	116	310	426	1.05	3,625	8.96

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	4,518

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
24,690,535	32,403,356	158,826,885	41%	80,808,780	127,742,070	569,031,090

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	22,348,270	3,471	3,631	20,804,779	16,233	5,632
ME	8,419,439	2,490	1,724	8,422,906	2,937	1,836
MA	18,083,041	36,978	11,021	18,096,120	37,044	11,037
NH	4,719,654	9,472	2,865	4,737,201	9,477	2,870
RI	2,419,681	21	418	2,419,681	21	418
VT	2,161,819	23	274	2,172,375	25	277
Total	**58,151,104**	**52,455**	**19,933**	**56,653,061**	**65,738**	**22,071**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,160	619,010	3,126,170	55,252,240	40,456,272	23%	20%	3%	1,244,420	1,267,540	228,343,458
2,105,350	3,026,340	5,131,690	21,945,690	15,500,927						
1,760,690	904,910	2,669,600	40,040,850	73,831,318						
674,410	2,065,640	2,740,050	21,368,140	14,450,182						
90,660	0	90,660	5,792,400	14,013,464						
571,310	444,960	1,016,270	9,894,914	9,246,022						
7,709,580	**7,064,860**	**14,774,440**	**154,294,234**	**167,504,187**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,507,160	619,010	17,180,600	11,865,977	22,359,070	37,440	295,650	22,692,160	32,172,747	54,864,907
ME	2,105,350	3,026,340	0	455,500	16,255,670	3,540	99,290	16,358,500	5,587,190	21,945,690
MA	1,760,690	904,910	5,597,850	6,323,580	24,998,400	26,360	425,050	25,449,810	14,591,040	40,040,850
NH	674,410	2,065,640	9,912,880	1,504,850	7,171,330	12,410	26,620	7,210,360	14,157,780	21,368,140
RI	90,660	0	0	0	5,701,740	0	0	5,701,740	90,660	5,792,400
VT	571,310	444,960	5,014,570	0	3,437,130	26,944	0	3,464,074	6,030,840	9,894,914
Total	**7,709,580**	**7,064,860**	**37,705,910**	**20,149,907**	**80,323,340**	**106,694**	**846,610**	**81,276,644**	**72,630,257**	**153,906,901**

Summary of Results: 2011 High Fuel/Growth Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
114.5	109.5	56%	7,196	35,151,628	37,980,107	-2,828,471	8,390	8,251	140	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	44	1,630	77	199	164	-416	8	76	2,095

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,024	453	-23	-94	41	7	67	5,146	14.64	123	199	321	0.91	5,468	15.55

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,820	413	2,234	6.35	123	199	321	0.91	2,555	7.27

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.9%	2,036

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
8,904,919	15,397,223	72,194,727	27%	32,831,563	76,720,129	304,338,432

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,639,511	15,642	7,250	11,841,934	37,926	10,197
ME	6,009,497	6,032	2,092	6,009,507	6,421	2,189
MA	22,337,753	88,011	22,930	22,337,076	88,068	22,940
NH	7,512,683	26,620	7,120	7,514,628	26,620	7,121
RI	1,874,915	16	324	1,874,915	16	324
VT	602,427	0	1	605,306	1	1
Total	49,976,786	136,321	39,717	50,173,366	159,052	42,771

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,410	616,360	3,123,770	37,979,840	35,151,628	11%	8%	3%	1,275,000	1,237,200	78,967,150
1,957,710	3,021,100	4,978,810	15,077,350	12,365,342						
1,684,440	773,500	2,457,940	37,535,260	61,126,883						
678,310	2,031,570	2,709,880	23,815,030	10,538,022						
92,830	0	92,830	4,542,140	11,646,713						
587,800	441,070	1,028,870	6,113,210	7,474,709						
7,508,500	6,883,600	14,392,100	125,062,830	138,303,296						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,410	616,360	17,201,880	4,010,420	10,079,980	16,530	3,547,260	13,643,770	24,336,070	37,979,840
ME	1,957,710	3,021,100	0	586,020	8,746,870	10	765,640	9,512,520	5,564,830	15,077,350
MA	1,684,440	773,500	5,597,850	12,669,070	12,938,780	1,650	3,869,960	16,810,390	20,724,870	37,535,260
NH	678,310	2,031,570	10,000,870	3,981,930	6,703,770	1,510	417,070	7,122,350	16,692,680	23,815,030
RI	92,830	0	0	0	4,449,310	0	0	4,449,310	92,830	4,542,140
VT	587,800	441,070	5,074,090	0	8,900	1,350	0	10,250	6,102,960	6,113,210
Total	7,508,500	6,883,600	37,874,700	21,247,440	42,927,610	21,050	8,599,930	51,548,590	73,514,240	125,062,830

Summary of Results: 2011 High Fuel/Growth Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
113.7	109.0	57%	7,033	34,947,699	37,910,324	-2,962,593	8,200	8,251	-51	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	44	1,622	77	197	149	-423	-3	94	2,872

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,974	443	-20	-93	35	9	67	5,076	14.52	220	197	418	1.20	5,493	15.72

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,781	413	2,194	6.28	220	197	418	1.20	2,611	7.47

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
20.6%	2,252

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
8,786,743	15,264,127	71,790,566	26%	32,542,906	76,344,263	302,751,186

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,603,041	15,608	7,223	11,804,518	37,874	10,179
ME	5,978,189	5,940	2,067	5,976,188	6,330	2,165
MA	22,299,406	87,964	22,913	22,287,717	88,014	22,972
NH	7,478,427	26,539	7,097	7,450,175	26,539	7,098
RI	1,860,842	16	321	1,860,842	16	321
VT	602,346	0	1	605,155	1	1
Total	**49,824,250**	**136,067**	**39,623**	**50,016,595**	**158,773**	**42,686**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,400	616,020	3,123,420	37,910,062	34,947,699	11%	8%	3%	1,274,910	1,237,280	78,133,655
1,957,870	3,020,750	4,978,620	15,028,140	12,365,342						
1,684,470	855,630	2,540,100	37,543,610	61,126,883						
678,210	2,031,050	2,709,260	23,754,770	10,538,022						
92,860	0	92,860	4,511,300	11,646,713						
587,750	441,000	1,028,750	6,112,860	7,474,709						
7,508,560	**6,964,450**	**14,473,810**	**124,860,742**	**138,099,367**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,507,400	616,020	17,201,880	4,012,920	10,026,990	14,322	3,530,530	13,571,842	24,338,220	37,910,062
ME	1,957,870	3,020,750	0	586,540	8,719,590	0	743,390	9,462,980	5,565,160	15,028,140
MA	1,684,470	855,630	5,597,860	12,675,040	12,878,480	1,260	3,850,870	16,730,610	20,813,000	37,543,610
NH	678,210	2,031,050	10,000,870	3,984,790	6,664,580	1,450	393,820	7,059,850	16,694,920	23,754,770
RI	92,860	0	0	0	4,418,440	0	0	4,418,440	92,860	4,511,300
VT	587,750	441,000	5,074,090	0	8,650	1,370	0	10,020	6,102,840	6,112,860
Total	**7,508,560**	**6,964,450**	**37,874,700**	**21,259,290**	**42,716,730**	**18,402**	**8,518,610**	**51,253,742**	**73,607,000**	**124,860,742**

Summary of Results: 2013 High Fuel/Growth Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSE/ ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
106.4	101.9	55%	7,431	35,821,252	37,510,361	-1,689,077	8,664	8,251	413	4.4	9.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	44	1,507	53	229	174	-294	22	103	2,152

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,813	461	-19	-90	28	8	67	4,908	13.70	121	229	350	0.98	5,258	14.68

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,850	413	2,263	6.32	121	229	350	0.98	2,613	7.29

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	2,036

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
9,975,296	15,620,439	73,819,031	27%	41,765,137	82,569,221	339,598,175

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,323,248	15,015	6,875	11,584,180	35,912	9,712
ME	6,842,749	5,678	2,146	6,842,373	6,116	2,255
MA	22,675,975	84,195	22,153	22,671,112	84,239	22,161
NH	7,414,839	26,652	7,116	7,415,392	26,652	7,116
RI	2,032,557	18	351	2,033,356	19	351
VT	550,728	0	1	553,161	1	1
Total	50,839,496	131,558	38,642	51,099,574	152,939	41,597

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,120	617,890	3,003,010	37,510,050	35,821,252	13%	10%	3%	1,131,930	1,257,990	120,277,724
2,093,880	3,020,750	5,114,630	17,174,250	12,743,007						
1,761,600	768,900	2,530,500	39,262,050	62,491,915						
708,950	2,027,470	2,736,420	23,612,300	10,955,032						
94,260	0	94,260	4,907,940	11,946,395						
539,210	440,670	979,880	5,959,870	7,669,557						
7,583,020	6,875,680	14,458,700	128,426,500	141,630,157						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,385,120	617,890	17,091,580	3,851,870	10,274,420	36,340	3,252,870	13,563,630	23,946,460	37,510,090
ME	2,093,880	3,020,750	0	661,990	10,803,900	20	593,710	11,397,630	5,776,620	17,174,250
MA	1,761,600	768,900	5,597,860	12,360,470	15,420,590	21,500	3,331,130	18,773,220	20,488,830	39,262,050
NH	708,950	2,027,470	10,000,870	4,102,330	6,524,450	350	247,880	6,772,680	16,839,620	23,612,300
RI	94,260	0	0	0	4,808,960	4,720	0	4,813,680	94,260	4,907,940
VT	539,210	440,670	4,969,930	0	8,720	1,340	0	10,060	5,949,810	5,959,870
Total	7,583,020	6,875,680	37,660,240	20,976,660	47,841,040	64,270	7,425,590	55,330,900	73,095,600	128,426,500

Summary of Results: 2013 High Fuel/Growth Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSE# ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/kWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
105.6	101.6	57%	7,109	35,272,768	37,698,174	-2,425,394	8,289	8,251	38	4.4	9.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	45	1,521	34	225	131	-339	2	155	2,138

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,726	443	-14	-88	30	8	67	4,799	13.60	300	225	525	1.49	5,324	15.09

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,758	413	2,171	6.16	300	225	525	1.49	2,696	7.64

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	2,485

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,143,294	15,580,025	74,445,477	28%	40,733,520	80,669,625	533,494,868

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,486,995	15,158	6,969	11,696,916	36,301	9,814
ME	6,226,145	6,035	2,117	6,226,950	6,473	2,226
MA	22,863,598	84,392	22,227	22,857,451	84,435	22,235
NH	7,598,890	26,821	7,183	7,599,787	26,821	7,184
RI	2,036,507	18	352	2,036,506	18	352
VT	550,614	0	1	552,953	0	1
Total	50,762,747	132,424	38,849	50,970,564	154,048	41,812

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,120	617,300	3,002,420	37,697,850	35,272,768	13%	10%	3%	1,131,940	1,257,980	117,584,781
2,093,920	3,021,440	5,115,360	15,547,710	12,743,007						
1,761,580	823,230	2,584,810	39,736,010	62,491,915						
708,960	2,029,610	2,738,570	24,013,250	10,958,032						
94,260	0	94,260	4,919,260	11,946,395						
539,220	440,670	979,890	5,959,860	7,669,557						
7,583,060	6,932,250	14,515,310	127,878,970	141,081,674						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,120	617,300	17,091,580	3,850,300	10,370,270	27,600	3,355,680	13,753,550	23,944,300	37,697,850
ME	2,093,920	3,021,440	0	662,590	9,091,350	630	677,380	9,769,760	5,777,950	15,547,710
MA	1,761,580	823,230	5,597,860	12,363,770	15,785,960	17,560	3,385,050	19,189,570	20,546,440	39,736,010
NH	708,960	2,029,610	10,000,870	4,104,440	6,890,350	370	283,680	7,174,400	16,843,840	24,018,240
RI	94,260	0	0	0	4,825,000	0	0	4,825,000	94,260	4,919,260
VT	539,220	440,670	4,969,930	0	8,930	1,110	0	10,040	5,949,820	5,959,860
Total	7,583,060	6,932,250	37,660,240	20,981,100	46,971,060	47,470	7,701,790	54,722,320	73,156,650	127,878,970

Summary of Results: 2018 High Fuel/Growth Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEr ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
113.4	105.8	54%	7,919	37,205,520	45,876,343	-8,670,786	9,234	10,047	-813	4.9	9.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
130	372	66	2,262	283	326	17	-924	-47	156	**2,692**

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,217	538	-31	-90	26	11	64	**5,445**	**14.64**	116	326	**442**	**1.19**	**5,887**	**15.82**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,210	413	**2,623**	**7.05**	116	326	**442**	**1.19**	**3,065**	**8.24**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,420

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
18,661,537	28,205,072	137,379,696	42%	52,544,701	94,415,342	404,168,554

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,010,981	14,683	7,081	14,625,431	33,667	9,778
ME	7,154,313	4,554	1,968	7,154,652	4,989	2,077
MA	21,677,286	78,704	20,806	21,670,031	78,736	20,811
NH	7,556,502	28,860	7,631	7,558,074	28,861	7,631
RI	1,542,869	13	266	1,543,212	14	267
VT	506,264	0	1	509,111	0	1
Total	**54,448,222**	**126,815**	**37,752**	**53,060,511**	**146,268**	**40,565**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,378,930	617,340	2,996,270	45,876,060	37,205,520	20%	17%	3%	1,211,000	1,172,730	224,058,714
2,010,900	3,021,340	5,032,240	18,324,820	13,537,869						
1,781,590	999,890	2,781,480	38,568,880	65,830,301						
697,070	2,029,760	2,726,830	23,384,550	11,897,230						
95,230	0	95,230	3,744,460	12,553,624						
494,430	440,800	935,230	6,019,670	8,115,192						
7,458,150	**7,109,130**	**14,567,280**	**135,918,440**	**149,139,734**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,378,930	617,340	17,180,880	4,207,710	19,358,580	29,830	2,102,790	21,491,200	24,384,860	45,876,060
ME	2,010,900	3,021,340	0	669,740	12,806,210	350	316,280	12,622,840	5,701,980	18,324,820
MA	1,781,590	999,890	5,597,860	12,343,070	15,490,190	12,150	1,944,130	17,846,470	20,722,410	38,568,880
NH	697,070	2,029,760	10,000,870	4,538,100	5,988,100	540	130,020	6,118,660	17,265,890	23,384,550
RI	95,230	0	0	0	3,647,220	2,010	0	3,649,230	95,230	3,744,460
VT	494,430	440,800	5,074,090	0	9,290	1,060	0	10,350	6,009,320	6,019,670
Total	**7,458,150**	**7,109,130**	**37,853,700**	**21,758,710**	**57,299,590**	**45,940**	**4,493,220**	**61,738,750**	**74,179,690**	**135,918,440**

Summary of Results: 2018 High Fuel/Growth Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
113.5	109.8	55%	7,302	35,484,718	42,407,372	-6,922,618	8,514	9,148	-634	4.1	9.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
93	344	56	1,948	259	311	29	-766	-31	303	2,546

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,029	423	-15	-89	29	10	69	5,124	14.44	172	311	483	1.36	5,608	15.80

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,932	413	2,345	6.61	172	311	483	1.36	2,829	7.97

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,342

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
14,972,881	23,251,240	111,939,552	37%	49,033,175	90,971,413	389,691,369

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	14,695,836	14,907	6,942	13,278,911	34,270	9,676
ME	7,264,921	4,683	2,014	7,265,221	5,119	2,123
MA	22,133,920	79,168	20,984	22,127,753	79,203	20,990
NH	7,663,220	29,005	7,680	7,664,916	29,605	7,681
RI	1,647,281	14	284	1,647,281	14	284
VT	906,563	1	1	569,719	0	1
Total	53,911,740	127,778	37,906	52,493,800	147,611	40,757

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,200	618,130	2,997,330	42,407,070	35,484,718	20%	17%	3%	1,211,190	1,172,810	211,235,395
2,011,300	3,021,190	5,032,490	18,559,360	13,537,869						
1,781,810	1,060,940	2,842,750	39,604,906	65,830,301						
697,410	2,029,960	2,727,370	23,607,707	11,897,230						
95,330	0	95,330	3,994,180	12,553,624						
494,520	441,140	935,660	6,020,960	5,115,192						
7,459,570	7,171,360	14,630,930	134,194,183	147,418,932						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,200	618,130	17,180,880	4,215,500	15,740,490	25,950	2,246,920	18,013,360	24,393,710	42,407,070
ME	2,011,300	3,021,190	0	670,690	12,511,250	300	344,630	12,856,180	5,703,180	18,559,360
MA	1,781,810	1,060,940	5,597,860	12,373,640	16,766,430	11,056	2,013,170	18,790,656	20,814,250	39,604,906
NH	697,410	2,029,960	10,000,870	4,550,440	6,182,670	557	145,800	6,329,027	17,278,680	23,607,707
RI	95,330	0	0	0	3,898,850	0	0	3,898,850	95,330	3,994,180
VT	494,520	441,140	5,074,090	0	10,020	1,190	0	11,210	6,009,750	6,020,960
Total	7,459,570	7,171,360	37,853,700	21,810,270	55,109,710	39,053	4,750,520	59,899,283	74,294,900	134,194,183

Summary of Results: 2018 High Fuel/Growth Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
111.3	105.6	54%	7,919	37,205,520	49,820,246	-12,614,684	9,234	10,348	-1,114	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
735	480	69	1,844	237	326	3	-1,267	-71	156	2,512

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION $VC COST + 15% PREMIUM	AVERAGE GENERATION $VC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,141	590	-26	-108	40	12	61	5,416	14.56	116	326	442	1.19	5,858	15.75

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION $VC COST	AVERAGE GENERATION $VC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,029	413	2,442	6.56	116	326	442	1.19	2,885	7.75

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,720

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,941,741	21,677,682	99,072,667	28%	45,243,899	83,273,637	342,026,325

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	13,361,508	14,061	6,443	12,121,701	32,244	9,043
ME	6,880,019	4,437	1,496	6,880,527	4,872	2,005
MA	20,719,801	77,415	20,361	20,719,245	77,460	20,371
NH	7,267,499	28,279	7,455	7,269,163	28,279	7,455
RI	1,308,827	11	226	1,308,827	11	226
VT	505,287	0	0	507,919	0	1
Total	**50,042,942**	**124,205**	**36,392**	**48,807,382**	**142,867**	**39,101**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)	(%)	(%)	(MWh)	(MWh)	($)
2,370,800	616,830	2,987,630	49,819,940	37,205,520	20%	17%	3%	1,205,350	1,170,250	224,306,260
2,008,080	3,022,030	5,030,110	17,676,710	13,537,969						
1,779,520	770,050	2,549,570	36,382,820	65,830,301						
695,550	2,029,370	2,724,920	22,830,700	11,897,239						
95,040	0	95,040	3,190,820	12,553,624						
493,720	440,360	934,080	6,017,910	3,115,192						
7,442,710	**6,878,640**	**14,321,350**	**135,918,900**	**149,139,734**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,370,800	616,830	26,864,210	4,132,680	13,953,570	25,390	1,856,460	15,835,420	33,984,520	49,819,940
ME	2,008,080	3,022,030	0	664,130	11,685,680	520	296,270	11,982,470	5,694,240	17,676,710
MA	1,779,520	770,050	5,597,860	12,199,380	14,192,348	16,150	1,827,520	16,036,018	20,346,810	36,382,820
NH	695,550	2,029,370	10,000,870	4,479,020	5,544,520	400	40,970	5,625,890	17,204,810	22,830,700
RI	95,040	0	0	0	3,095,780	0	0	3,095,780	95,040	3,190,820
VT	493,720	440,360	5,074,090	0	8,930	810	0	9,740	6,008,170	6,017,910
Total	**7,442,710**	**6,878,640**	**47,537,030**	**21,475,210**	**48,480,828**	**43,270**	**4,041,220**	**52,585,318**	**83,333,590**	**135,918,900**

Summary of Results: 2018 High Fuel/Growth Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
111.3	105.6	54%	7,919	37,205,520	49,820,246	-12,614,684	9,234	10,348	-1,114	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
425	406	109	2,028	402	326	3	-1,267	-71	156	2,519

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,141	590	-26	-108	40	12	61	5,416	14.56	116	326	442	1.19	5,858	15.75

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,036	413	2,450	6.58	116	326	442	1.19	2,892	7.77

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,720

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,941,741	21,677,682	99,072,667	28%	45,243,899	83,273,637	342,026,325

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	21,495,120	14,061	6,443	20,255,314	32,244	9,043
ME	6,880,019	4,437	1,896	6,880,527	4,972	2,005
MA	20,719,801	77,415	20,361	20,719,245	77,460	20,371
NH	7,267,499	28,279	7,455	7,269,163	28,279	7,455
RI	1,308,827	11	226	1,308,827	11	226
VT	505,287	0	0	507,919	0	1
Total	**58,176,554**	**124,205**	**36,382**	**56,940,994**	**142,867**	**39,101**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,370,800	616,830	2,987,630	49,819,940	37,205,520	20%	17%	3%	1,205,350	1,170,250	224,306,260
2,008,080	3,022,030	5,030,110	17,676,710	13,537,869						
1,779,520	770,050	2,549,570	36,382,820	65,830,301						
695,550	2,029,370	2,724,920	22,830,700	11,897,239						
95,040	0	95,040	3,190,820	12,553,624						
493,720	440,360	934,080	6,017,910	8,115,192						
7,442,710	**6,878,640**	**14,321,350**	**135,918,900**	**149,139,734**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,370,800	616,830	17,180,880	13,428,677	13,953,570	25,390	1,856,460	15,835,420	33,597,187	49,432,607
ME	2,008,080	3,022,030	0	664,130	11,695,860	520	296,270	11,982,470	5,694,240	17,676,710
MA	1,779,520	770,050	5,597,860	12,199,380	14,192,340	16,150	1,827,520	16,036,010	20,346,810	36,382,820
NH	695,550	2,029,370	10,000,870	4,479,020	5,544,520	400	80,970	5,625,890	17,204,810	22,830,700
RI	95,040	0	0	0	3,095,780	0	0	3,095,780	95,040	3,190,820
VT	493,720	440,360	5,074,090	0	8,930	810	0	9,740	6,008,170	6,017,910
Total	**7,442,710**	**6,878,640**	**37,853,700**	**30,771,207**	**48,490,020**	**43,270**	**4,061,220**	**52,585,310**	**82,946,257**	**135,531,567**

Summary of Results: 2030 High Fuel/Growth Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
122.7	116.8	53%	8,965	41,834,315	53,826,644	-11,992,289	10,453	11,847	-1,393	8.1	5.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
362	430	87	3,211	568	321	15	-1,359	-136	156	3,655

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,131	1,018	-67	-99	10	42	41	6,949	16.71	116	321	437	1.04	7,424	17.75

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,178	413	3,591	8.58	116	321	437	1.04	4,028	9.63

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,005

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,668,462	40,598,720	198,699,947	52%	82,757,080	133,975,762	565,950,383

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	18,742,811	12,774	6,868	17,392,460	29,528	9,349
ME	8,340,710	3,911	2,031	8,341,983	4,357	2,142
MA	24,126,111	76,643	20,787	24,130,615	76,721	20,804
NH	7,023,482	28,636	7,498	7,030,741	28,699	7,496
RI	1,938,968	17	335	1,938,968	17	335
VT	2,302,726	30	300	2,307,648	32	301
Total	62,514,808	122,010	37,814	61,182,415	139,295	40,429

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,522,460	619,700	3,142,160	53,826,350	41,834,315	23%	20%	3%	1,253,890	1,273,370	237,219,236
2,105,030	3,026,750	5,131,780	21,504,230	15,783,869						
1,760,530	1,423,400	3,183,930	45,590,370	75,149,717						
674,320	2,077,300	2,751,620	22,098,230	14,208,453						
90,650	0	90,650	4,708,320	14,263,839						
571,240	446,840	1,018,080	10,212,227	9,411,148						
7,724,230	7,593,990	15,318,220	157,939,727	171,151,340						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,522,460	619,700	17,180,600	4,098,320	28,167,030	35,310	1,202,930	29,405,270	24,421,080	53,826,350
ME	2,105,030	3,026,750	0	699,320	15,545,240	1,300	126,590	15,673,130	5,831,100	21,504,230
MA	1,760,530	1,423,400	5,597,860	12,285,880	23,011,240	14,020	1,497,440	24,522,700	21,067,670	45,590,370
NH	674,320	2,077,300	9,912,880	4,589,920	4,823,520	8,740	11,510	4,843,810	17,254,420	22,098,230
RI	90,650	0	0	0	4,617,670	0	0	4,617,670	90,650	4,708,320
VT	571,240	446,840	5,014,570	0	4,139,827	39,750	0	4,179,577	6,032,650	10,212,227
Total	7,724,230	7,593,990	37,705,910	21,673,440	80,384,527	99,160	2,838,470	83,242,157	74,697,570	157,939,727

Summary of Results: 2030 High Fuel/Growth Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
123.5	119.1	55%	8,266	39,900,137	52,934,914	-13,034,735	9,639	11,547	-1,908	7.0	7.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
331	420	85	3,121	560	306	5	-1,525	-160	232	3,375

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for "Overcounting Losses"	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,928	807	-37	-95	15	30	49	6,552	16.42	172	306	478	1.20	7,030	17.62

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,857	413	3,250	8.15	172	306	478	1.20	3,728	9.34

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	4,636

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
27,608,124	39,014,358	191,351,978	51%	78,448,937	129,741,519	549,995,272

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,551,288	13,120	6,934	17,120,563	30,332	9,476
ME	8,490,433	3,909	2,047	8,491,904	4,344	2,158
MA	23,839,692	77,542	20,935	23,843,616	77,624	20,953
NH	7,223,238	28,967	7,601	7,230,313	28,970	7,604
RI	1,955,328	17	338	1,955,328	17	338
VT	1,966,715	22	241	1,971,690	23	242
Total	**62,027,194**	**123,565**	**38,094**	**60,613,415**	**141,311**	**40,771**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,540	619,910	3,143,450	52,934,595	39,900,137	23%	20%	3%	1,254,540	1,273,800	224,296,506
2,105,850	3,026,830	5,132,680	21,783,814	15,783,869						
1,761,110	1,389,020	3,150,130	44,627,880	75,149,717						
674,620	2,074,170	2,748,790	22,501,380	14,706,453						
90,730	0	90,730	4,753,130	14,263,839						
571,490	446,760	1,018,250	9,406,180	9,411,148						
7,727,340	**7,556,690**	**15,284,030**	**156,006,979**	**169,217,163**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,523,540	619,910	17,180,600	4,137,690	27,093,370	24,835	1,354,650	28,472,855	24,461,740	52,934,595
ME	2,105,850	3,026,830	0	703,810	15,926,430	1,524	117,370	15,947,324	5,836,490	21,783,814
MA	1,761,110	1,389,020	5,597,860	12,409,730	21,908,990	14,070	1,547,100	23,470,160	21,157,720	44,627,880
NH	674,620	2,074,170	9,912,880	4,641,340	5,176,120	8,380	13,870	5,198,370	17,303,010	22,501,380
RI	90,730	0	0	0	4,662,400	0	0	4,662,400	90,730	4,753,130
VT	571,490	446,760	5,014,570	0	3,346,290	27,070	0	3,373,360	6,032,820	9,406,180
Total	**7,727,340**	**7,556,690**	**37,705,910**	**21,892,570**	**78,015,600**	**75,879**	**3,032,990**	**81,124,469**	**74,882,510**	**156,006,979**

Summary of Results: 2030 High Fuel/Growth Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
120.3	113.4	53%	8,965	41,834,315	58,190,024	-16,355,665	10,453	12,747	-2,293	7.8	6.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
973	556	92	2,792	494	321	0	-1,780	-215	156	3,389

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,031	981	-70	-118	14	47	43	6,819	16.30	116	321	437	1.04	7,256	17.35

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,912	413	3,326	7.95	116	321	437	1.04	3,763	8.99

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NE NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
23,628,554	35,849,690	163,006,192	40%	72,011,881	122,494,272	503,328,579

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,247,743	12,397	6,346	15,136,673	28,554	8,754
ME	8,433,004	3,943	2,046	8,434,708	4,389	2,158
MA	23,452,470	76,493	20,640	23,466,772	76,577	20,659
NH	7,131,780	28,551	7,494	7,138,380	28,554	7,496
RI	1,868,670	16	323	1,868,670	16	323
VT	1,256,506	11	117	1,260,901	12	118
Total	**58,400,177**	**121,411**	**36,966**	**57,306,105**	**138,103**	**39,507**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,484,140	617,230	3,101,370	58,189,740	41,834,315	23%	20%	3%	1,231,520	1,257,390	237,965,280
2,104,980	3,024,570	5,129,550	21,617,588	15,783,869						
1,760,480	959,770	2,720,250	43,546,540	25,149,717						
674,300	2,068,810	2,743,110	22,379,950	14,708,453						
90,650	0	90,650	4,546,350	14,263,839						
571,220	446,020	1,017,240	7,674,420	9,411,148						
7,685,770	**7,116,400**	**14,802,170**	**157,954,588**	**171,151,340**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,484,140	617,230	26,863,930	4,011,920	23,083,820	36,470	1,092,230	24,212,520	33,977,220	58,189,740
ME	2,104,980	3,024,570	0	699,820	15,652,720	1,748	133,750	15,788,218	5,829,370	21,617,588
MA	1,760,480	959,770	5,597,860	12,257,630	21,449,640	12,210	1,508,960	22,970,810	20,575,730	43,546,540
NH	674,300	2,068,810	9,912,880	4,577,160	5,129,250	7,390	10,160	5,146,800	17,233,150	22,379,950
RI	90,650	0	0	0	4,455,700	0	0	4,455,700	90,650	4,546,350
VT	571,220	446,020	5,014,570	0	1,627,300	15,310	0	1,642,610	6,031,810	7,674,420
Total	**7,685,770**	**7,116,400**	**47,389,240**	**21,546,520**	**71,398,430**	**73,128**	**2,745,100**	**74,216,658**	**83,737,930**	**157,954,588**

Summary of Results: 2030 High Fuel/Growth Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
120.3	113.4	53%	5,965	41,834,315	58,190,024	-16,355,665	10,453	12,747	-2,293	7.8	6.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
663	483	132	2,981	783	321	0	-1,730	-215	156	3,524

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,031	981	-70	-118	14	47	43	6,819	16.30	116	321	437	1.04	7,256	17.35

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,047	413	3,460	8.27	116	321	437	1.04	3,897	9.32

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)	(MMBtu)	(MMBtu)
23,628,534	35,849,690	163,006,192	40%	72,011,881	122,498,272	503,328,579

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	24,381,355	12,397	6,346	23,270,286	28,554	8,754
ME	8,433,008	3,943	2,046	8,434,708	4,389	2,154
MA	23,462,470	76,493	20,640	23,466,772	76,577	20,659
NH	7,131,780	28,551	7,494	7,133,380	28,554	7,496
RI	1,858,670	16	323	1,868,670	16	323
VT	1,256,506	11	117	1,260,901	12	118
Total	**66,533,789**	**121,411**	**36,966**	**65,439,717**	**138,103**	**39,507**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,484,140	617,230	3,101,370	58,189,740	41,834,315	23%	20%	3%	1,231,520	1,257,390	237,965,240
2,104,980	3,024,570	5,129,550	21,617,588	15,783,869						
1,760,480	959,770	2,720,250	43,546,540	75,149,717						
674,300	2,068,810	2,743,110	22,379,959	14,708,453						
90,650	0	90,650	4,546,350	14,263,839						
571,220	446,020	1,017,240	7,674,420	9,411,148						
7,685,770	**7,116,400**	**14,802,170**	**157,954,588**	**171,151,340**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,484,140	617,230	17,180,600	13,307,917	23,083,820	36,470	1,092,230	24,212,520	33,589,887	57,802,407
ME	2,104,980	3,024,570	0	699,820	15,652,720	1,748	133,750	15,788,218	5,829,370	21,617,588
MA	1,760,480	959,770	5,597,860	12,257,920	21,449,640	12,210	1,508,960	22,970,810	20,575,730	43,546,540
NH	674,300	2,068,810	9,912,880	4,577,160	5,129,250	7,390	10,160	5,146,800	17,233,150	22,379,950
RI	90,650	0	0	0	4,455,700	0	0	4,455,700	90,650	4,546,350
VT	571,220	446,020	5,014,570	0	1,627,300	15,310	0	1,642,610	6,031,810	7,674,420
Total	7,685,770	7,116,400	37,705,910	30,842,817	71,398,430	73,128	2,745,100	74,216,658	83,350,597	157,567,255

Summary of Results: 2011 Low Stress Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
53.9	51.9	59%	7,380	38,049,374	36,771,453	1,277,907	8,605	8,251	354	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	814	40	821	51	215	168	-79	19	76	1,625

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,051	465	-8	-49	15	2	67	2,925	7.69	123	215	338	0.89	3,262	8.57

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,334	413	1,747	4.59	123	215	338	0.89	2,084	5.48

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.0%	1,797

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,797,520	17,970,888	87,278,666	33%	57,129,726	105,175,546	490,310,721

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,680,309	6,125	4,172	9,830,066	22,990	6,612
ME	6,551,225	3,290	1,593	6,551,555	3,678	1,690
MA	20,783,670	47,636	13,808	20,737,449	47,631	13,798
NH	6,314,312	14,774	4,303	6,320,037	14,775	4,304
RI	4,170,744	36	720	4,172,856	39	721
VT	605,309	3	3	617,435	4	4
Total	**48,105,569**	**71,864**	**24,598**	**48,229,398**	**89,117**	**27,129**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,850	615,460	3,124,310	36,771,150	38,049,374	11%	8%	3%	1,275,980	1,237,660	90,826,097
1,959,050	1,020,390	4,979,440	17,166,690	13,486,356						
1,685,440	954,860	2,640,300	43,461,563	66,668,114						
679,060	2,023,990	2,703,050	23,950,120	11,493,296						
92,770	0	92,770	9,833,230	12,702,495						
588,290	438,770	1,027,060	6,124,330	8,152,408						
7,513,460	**7,053,470**	**14,566,930**	**137,307,083**	**150,552,042**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,850	615,460	17,201,880	2,912,240	11,993,320	20,430	1,518,970	13,532,720	23,238,430	36,771,150
ME	1,959,050	1,020,390	0	417,650	11,442,340	340	326,920	11,769,600	5,397,090	17,166,690
MA	1,685,440	954,860	5,597,860	7,306,590	26,223,560	10,213	1,683,040	27,916,813	15,544,750	43,461,563
NH	679,060	2,023,990	10,000,870	2,189,790	8,780,530	3,280	272,600	9,056,410	14,893,710	23,950,120
RI	92,770	0	0	0	9,727,970	12,490	0	9,740,460	92,770	9,833,230
VT	588,290	438,770	5,074,090	0	14,440	8,740	0	23,180	6,101,150	6,124,330
Total	**7,513,460**	**7,053,470**	**37,874,700**	**12,826,270**	**68,182,160**	**55,493**	**3,801,530**	**72,039,183**	**65,267,900**	**137,307,083**

Summary of Results: 2011 Low Stress Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
54.1	52.2	66%	7,215	37,648,904	37,049,707	599,205	8,412	8,251	161	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	41	333	52	213	146	-94	9	94	1,609

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,038	454	-7	-48	15	3	67	2,900	7.70	220	213	433	1.15	3,333	8.85

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,302	413	1,715	4.56	220	213	433	1.15	2,148	5.71

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	2,012

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,067,443	18,144,676	88,410,296	33%	56,081,947	103,645,045	484,552,190

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,856,700	6,368	4,280	10,014,857	23,577	6,770
ME	6,583,605	3,390	1,618	6,583,952	3,768	1,715
MA	20,504,199	49,254	14,115	20,452,241	49,229	14,100
NH	6,433,686	15,372	4,455	6,439,881	15,374	4,456
RI	4,308,235	37	744	4,309,089	38	744
VT	605,388	3	3	618,096	4	4
Total	**48,291,814**	**74,414**	**25,215**	**48,418,116**	**91,991**	**27,790**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,509,160	615,520	3,124,680	37,049,390	37,648,904	11%	8%	3%	1,276,150	1,237,800	89,171,495
1,959,260	3,020,750	4,980,010	17,223,250	13,486,356						
1,685,620	944,230	2,629,850	42,283,955	66,668,113						
679,160	2,024,210	2,703,370	24,089,810	11,493,296						
92,720	0	92,720	10,141,900	12,702,495						
588,320	438,840	1,027,160	6,125,130	3,152,408						
7,514,240	**7,043,550**	**14,557,790**	**136,913,435**	**150,151,572**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,509,160	615,520	17,201,880	2,940,420	12,134,990	21,200	1,626,220	13,782,410	23,266,980	37,049,390
ME	1,959,260	3,020,750	0	426,270	11,478,940	360	317,670	11,816,970	5,406,280	17,223,250
MA	1,685,620	944,230	5,597,860	7,546,050	24,752,770	11,285	1,746,140	26,510,195	15,773,760	42,283,955
NH	679,160	2,024,210	10,000,870	2,278,760	8,818,290	3,440	285,080	9,106,810	14,983,000	24,089,810
RI	92,720	0	0	0	10,044,130	5,050	0	10,049,180	92,720	10,141,900
VT	588,320	438,840	5,074,090	0	14,860	9,020	0	23,880	6,101,250	6,125,130
Total	**7,514,240**	**7,043,550**	**37,874,700**	**13,191,500**	**67,243,980**	**50,355**	**3,995,110**	**71,289,445**	**65,623,990**	**136,913,435**

Summary of Results: 2013 Low Stress Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
51.2	49.4	59%	7,622	39,117,038	38,813,659	303,379	8,887	8,550	337	3.3	10.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
23	323	47	360	61	250	122	-87	13	103	1,714

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,003	351	-7	-44	14	3	75	2,755	7.04	121	250	371	0.95	3,126	7.99

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,361	413	1,774	4.54	121	250	371	0.95	2,145	5.48

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	2,105

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
13,470,101	21,174,018	105,291,286	37%	64,093,035	115,310,015	549,462,783

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,449,987	5,318	4,063	10,632,248	21,128	6,328
ME	8,294,082	3,119	1,936	8,294,117	3,557	1,945
MA	19,817,511	36,246	11,125	19,781,886	36,364	11,134
NH	5,414,470	10,451	3,196	5,418,033	10,451	3,197
RI	4,233,827	37	731	4,266,184	80	746
VT	553,186	1	1	560,287	2	3
Total	**48,763,062**	**55,212**	**20,953**	**48,952,754**	**71,581**	**23,352**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,280	615,590	3,000,870	38,813,340	39,117,038	13%	10%	3%	1,132,130	1,257,940	136,446,606
2,093,810	3,020,420	5,114,230	21,416,460	14,068,666						
1,761,640	974,930	2,736,570	43,698,660	68,992,655						
709,020	2,023,730	2,732,750	22,879,210	12,097,999						
94,150	0	94,150	9,957,670	13,189,124						
539,270	438,860	978,130	5,967,329	8,467,445						
7,583,170	**7,073,530**	**14,656,700**	**142,732,669**	**155,932,889**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,280	615,590	17,091,580	2,469,670	14,496,230	43,670	1,711,320	16,251,220	22,562,120	38,813,340
ME	2,093,810	3,020,420	0	359,870	15,573,270	30	369,060	15,942,360	5,474,100	21,416,460
MA	1,761,640	974,930	5,592,860	5,240,820	28,321,730	35,390	1,766,290	30,123,410	13,575,250	43,698,660
NH	709,020	2,023,730	10,000,870	1,540,300	8,402,710	1,650	200,930	8,605,290	14,273,920	22,879,210
RI	94,150	0	0	0	9,671,920	191,600	0	9,863,520	94,150	9,957,670
VT	539,270	438,860	4,969,930	0	15,030	4,239	0	19,269	5,948,060	5,967,329
Total	**7,583,170**	**7,073,530**	**37,660,240**	**9,610,660**	**76,480,890**	**276,579**	**4,047,600**	**80,805,069**	**61,927,600**	**142,732,669**

Summary of Results: 2013 Low Stress Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM + 1.0% loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
51.1	49.4	60%	7,295	38,026,450	38,880,567	-854,112	8,506	8,550	-43	3.2	10.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
23	323	47	362	61	243	89	-113	-2	155	1,687

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,942	331	-3	-43	15	3	76	2,669	7.02	300	243	542	1.43	3,211	8.44

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
1,290	413	1,703	4.48	300	243	542	1.43		2,246	5.91

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	2,534

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
13,647,823	21,127,937	105,900,023	37%	62,734,869	113,101,078	541,071,853

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,478,431	5,307	4,067	10,658,903	21,133	6,334
ME	7,600,435	3,445	1,768	7,600,715	3,383	1,897
MA	19,920,764	36,465	11,182	19,843,829	36,544	11,192
NH	5,564,581	10,625	3,258	5,568,312	10,625	3,259
RI	4,285,984	37	740	4,319,304	87	755
VT	552,999	1	1	559,533	1	2
Total	**48,403,194**	**55,879**	**21,037**	**48,590,595**	**72,268**	**23,439**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,460	615,590	3,001,050	38,880,210	38,026,450	13%	10%	3%	1,132,180	1,258,070	131,090,555
2,094,240	3,020,750	5,114,990	19,611,030	14,068,666						
1,761,790	987,650	2,749,440	43,919,510	68,992,625						
709,140	2,023,880	2,733,020	23,158,420	12,097,999						
94,230	0	94,230	10,072,630	13,189,124						
539,320	438,880	978,200	5,966,838	9,467,445						
7,584,180	**7,086,750**	**14,670,930**	**141,648,638**	**154,842,309**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,460	615,590	17,091,580	2,478,380	14,567,460	34,880	1,706,860	16,309,200	22,571,010	38,880,210
ME	2,094,240	3,020,750	0	380,190	13,694,550	290	421,010	14,115,850	5,495,180	19,611,030
MA	1,761,790	987,650	5,597,850	5,277,550	28,498,980	29,130	1,766,550	30,294,660	13,624,850	43,919,510
NH	709,140	2,023,880	10,000,870	1,537,890	8,678,650	1,420	246,570	8,926,640	14,231,780	23,158,420
RI	94,230	0	0	0	9,781,100	197,300	0	9,978,400	94,230	10,072,630
VT	539,320	438,880	4,969,930	0	15,260	3,448	0	18,708	5,944,130	5,966,838
Total	**7,584,180**	**7,086,750**	**37,660,240**	**9,674,010**	**75,236,000**	**266,468**	**4,140,990**	**79,643,458**	**62,905,180**	**141,648,638**

Summary of Results: 2018 Low Stress Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.04 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.9	53.7	59%	8,123	41,761,644	49,032,530	-7,270,851	9,471	10,347	-875	3.1	10.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
154	375	73	1,253	195	366	19	-396	-32	156	2,173

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,335	348	-19	-46	15	3	77	3,119	7.47	116	366	482	1.15	3,601	8.62

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,651	413	2,064	4.94	116	366	482	1.15	2,546	6.10

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	3,455

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,706,899	36,170,443	185,288,212	53%	89,753,010	137,292,054	676,842,788

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	15,880,682	3,413	3,945	14,178,225	15,976	5,829
ME	8,974,253	1,788	1,674	8,974,750	2,223	1,783
MA	19,354,554	24,272	8,413	19,297,326	24,236	8,396
NH	4,866,662	6,812	2,302	4,873,781	6,814	2,304
RI	4,119,141	36	711	4,139,695	63	721
VT	514,905	2	2	521,755	3	4
Total	**53,710,167**	**36,324**	**17,047**	**51,985,533**	**49,317**	**19,036**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,310	615,580	2,994,890	49,032,210	41,761,644	20%	17%	3%	1,211,270	1,172,830	261,488,033
2,011,340	3,020,420	5,031,760	23,510,850	15,433,413						
1,781,870	914,620	2,696,490	45,409,090	75,047,489						
697,410	2,024,470	2,721,880	22,469,910	13,563,667						
95,240	0	95,240	9,696,710	14,311,295						
494,550	438,890	933,440	6,032,430	9,251,557						
7,459,720	**7,013,980**	**14,473,700**	**156,151,200**	**169,369,466**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,310	615,580	17,180,880	2,159,350	25,803,380	32,550	861,160	26,697,090	22,335,120	49,032,210
ME	2,011,340	3,020,420	0	304,850	18,051,670	540	122,030	18,174,240	5,336,610	23,510,850
MA	1,781,870	914,620	5,597,860	3,745,550	32,516,060	27,730	825,400	33,369,190	12,039,900	45,409,090
NH	697,410	2,024,470	10,000,870	1,073,290	8,637,890	4,440	31,500	8,673,830	13,796,040	22,469,910
RI	95,240	0	0	0	9,479,770	121,700	0	9,601,470	95,240	9,696,710
VT	494,550	438,890	5,074,090	0	16,810	8,090	0	24,900	6,007,530	6,032,430
Total	**7,459,720**	**7,013,980**	**37,853,700**	**7,283,040**	**94,505,580**	**195,090**	**1,840,090**	**96,540,760**	**59,610,440**	**156,151,200**

Summary of Results: 2018 Low Stress Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSE# ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.7	53.8	59%	7,499	38,987,396	49,225,310	-10,237,876	8,743	10,347	-1,604	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
154	375	73	1,260	197	342	5	-535	-56	303	2,118

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spot	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,171	304	-9	-43	16	3	78	2,898	7.43	172	342	514	1.32	3,412	8.75

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,473	413	1,886	4.84	172	342	514	1.32	2,400	6.16

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.7%	4,276

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,345,419	36,462,310	186,492,140	53%	85,662,368	133,202,424	656,985,885

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	15,998,110	3,473	4,001	14,295,961	16,250	5,908
ME	8,248,330	2,008	1,598	8,248,872	2,444	1,707
MA	18,694,331	24,193	8,283	18,635,209	24,150	8,264
NH	5,030,516	7,098	2,393	5,037,960	7,100	2,395
RI	4,209,914	36	727	4,234,040	69	734
VT	513,969	2	2	520,940	3	4
Total	**52,695,170**	**36,811**	**17,004**	**50,972,983**	**50,015**	**19,014**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,560	615,540	2,995,100	49,225,010	38,987,396	20%	17%	3%	1,211,300	1,172,960	237,313,519
2,011,630	3,020,750	5,032,390	21,657,680	15,433,413						
1,782,070	936,010	2,718,080	43,768,180	75,047,489						
697,550	2,024,400	2,721,950	22,796,370	13,563,067						
95,340	0	95,340	9,905,830	14,311,295						
494,600	438,860	933,460	6,032,011	9,251,557						
7,460,750	**7,035,560**	**14,496,310**	**153,385,081**	**166,594,217**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,560	615,540	17,180,880	2,174,480	25,937,600	24,940	912,010	26,874,550	22,350,460	49,225,010
ME	2,011,630	3,020,750	0	327,610	16,150,590	370	146,530	16,297,690	5,359,990	21,657,680
MA	1,782,070	936,010	5,597,860	3,730,470	30,877,740	23,670	820,360	31,721,770	12,046,410	43,768,180
NH	697,550	2,024,400	10,000,870	1,102,120	8,912,000	4,060	55,370	8,971,430	13,824,940	22,796,370
RI	95,340	0	0	0	9,667,630	142,860	0	9,810,490	95,340	9,905,830
VT	494,600	438,860	5,074,090	0	17,470	6,991	0	24,461	6,007,550	6,032,011
Total	**7,460,750**	**7,035,560**	**37,853,700**	**7,334,680**	**91,563,030**	**203,091**	**1,934,270**	**93,700,391**	**59,684,690**	**153,385,081**

Summary of Results: 2018 Low Stress Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.1	52.5	59%	8,123	41,761,644	53,610,563	-11,848,876	9,471	10,947	-1,475	3.2	10.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
576	481	77	1,155	166	366	1	-592	-57	156	2,330

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,302	366	-17	-56	15	4	76	3,092	7.40	116	366	482	1.15	3,574	8.56

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,807	413	2,221	5.32	116	366	482	1.15	2,703	6.47

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,054

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
21,460,406	30,234,897	149,855,791	39%	80,326,898	125,901,496	609,989,583

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	13,723,283	3,347	3,555	12,068,944	15,663	5,400
ME	8,183,621	1,900	1,563	8,184,140	2,334	1,672
MA	18,197,774	23,547	8,056	18,140,888	23,506	8,038
NH	4,962,599	6,854	2,328	4,969,600	6,856	2,329
RI	4,058,853	35	701	4,062,888	67	712
VT	513,539	2	2	520,071	3	3
Total	**49,639,670**	**35,684**	**16,205**	**47,966,531**	**48,410**	**18,154**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,367,290	614,680	2,981,970	53,610,260	41,761,644	20%	17%	3%	1,204,100	1,167,970	262,015,108
2,010,490	3,020,430	5,031,320	21,523,450	15,433,413						
1,781,760	898,140	2,679,900	42,740,918	75,047,489						
697,300	2,024,370	2,721,670	22,691,710	13,563,067						
94,980	0	94,980	9,556,170	14,311,295						
494,530	438,790	933,320	6,030,864	9,251,557						
7,446,750	**6,996,410**	**14,443,160**	**156,153,772**	**169,369,466**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,367,290	614,680	26,864,210	2,110,550	20,767,350	27,630	858,550	21,653,530	31,956,730	53,610,260
ME	2,010,490	3,020,430	0	311,730	16,039,560	520	140,720	16,180,800	5,343,050	21,523,850
MA	1,781,760	898,140	5,597,860	3,629,910	30,016,480	20,558	796,210	30,833,248	11,907,670	42,740,918
NH	697,300	2,024,370	10,000,870	1,065,790	8,848,330	4,250	50,800	8,903,380	13,788,330	22,691,710
RI	94,980	0	0	0	9,318,880	142,310	0	9,461,190	94,980	9,556,170
VT	494,530	438,790	5,074,090	0	16,750	6,704	0	23,454	6,007,410	6,030,864
Total	**7,446,750**	**6,996,410**	**47,537,030**	**7,117,980**	**85,007,350**	**201,972**	**1,846,290**	**87,055,602**	**69,098,170**	**156,153,772**

Summary of Results: 2018 Low Stress Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.1	52.5	59%	8,123	41,761,644	53,610,563	-11,848,876	9,471	10,947	-1,475	3.2	10.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
351	414	114	1,318	293	366	1	-592	-57	156	2,364

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,302	366	-17	-56	15	4	76	3,092	7.40	116	366	482	1.15	3,574	8.56

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,842	413	2,255	5.40	116	366	482	1.15	2,737	6.55

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,054

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
21,460,406	30,234,897	148,855,791	39%	80,326,898	125,901,496	609,989,993

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	21,856,895	3,347	3,555	20,202,556	15,663	5,400
ME	8,183,621	1,900	1,563	8,184,140	2,334	1,672
MA	18,197,774	29,547	8,056	18,140,888	23,506	8,038
NH	4,962,599	6,854	2,328	4,969,600	6,856	2,329
RI	4,058,853	35	701	4,062,888	67	712
VT	513,539	2	2	520,071	3	3
Total	57,773,282	35,684	16,205	56,100,143	48,430	18,154

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,367,290	614,680	2,981,970	53,610,260	41,761,644	20%	17%	3%	1,204,100	1,167,970	262,015,108
2,010,890	3,020,430	5,031,320	21,523,850	15,433,413						
1,781,760	898,140	2,679,900	42,740,918	75,047,489						
697,300	2,024,370	2,721,670	22,691,710	13,563,067						
94,980	0	94,980	9,556,170	14,311,295						
494,530	438,790	933,320	6,030,864	9,251,557						
7,446,750	6,996,410	14,443,160	156,153,772	169,368,466						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,367,290	614,680	17,180,880	11,406,547	20,767,350	27,630	858,550	21,653,530	31,569,397	53,222,927
ME	2,010,890	3,020,430	0	311,730	16,039,560	520	140,720	16,180,800	5,343,050	21,523,850
MA	1,781,760	898,140	5,597,850	3,629,910	30,016,410	20,558	796,210	30,833,248	11,907,670	42,740,918
NH	697,300	2,024,370	10,000,870	1,065,790	8,448,330	4,250	50,800	8,903,380	13,788,330	22,691,710
RI	94,980	0	0	0	9,318,880	142,310	0	9,461,190	94,980	9,556,170
VT	494,530	438,790	5,074,090	0	16,750	6,704	0	23,454	6,007,410	6,030,864
Total	7,446,750	6,996,410	37,853,700	16,413,977	85,007,250	201,972	1,846,280	87,055,602	68,710,837	155,766,439

Summary of Results: 2030 Low Stress Scenario, Conventional Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
62.8	59.5	58%	9,196	46,957,157	57,773,738	-10,816,580	10,722	12,147	-1,424	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
286	428	94	1,682	406	360	11	-623	-72	156	2,729

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION $VC COST + 15% PREMIUM	AVERAGE GENERATION $VC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,950	541	-53	-55	10	12	69	**3,993**	**8.50**	116	360	**476**	**1.01**	**4,470**	**9.52**

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION $VC COST	AVERAGE GENERATION $VC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
2,213	413	**2,626**	**5.59**	116	360	**476**	**1.01**		**3,102**	**6.61**

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,006

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
39,954,200	50,260,360	254,141,323	62%	128,120,277	178,164,952	866,016,581

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,677,299	2,104	3,766	16,972,654	9,148	4,103
ME	9,873,936	1,787	1,416	9,879,652	2,233	1,929
MA	21,834,189	19,892	7,865	21,811,928	19,824	7,867
NH	4,885,543	7,582	2,475	4,905,616	7,530	2,469
RI	5,395,732	47	932	5,397,682	49	933
VT	2,198,071	39	283	2,213,361	43	288
Total	**62,864,770**	**31,450**	**17,156**	**61,180,893**	**38,827**	**18,288**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,521,650	617,250	3,138,900	57,773,380	46,957,157	23%	20%	3%	1,253,270	1,273,170	275,929,945
2,103,560	3,021,980	5,125,540	25,683,280	17,993,493						
1,759,740	880,530	2,640,270	52,666,730	85,671,896						
673,360	2,060,490	2,733,850	22,254,560	16,767,906						
90,240	0	90,240	12,884,470	16,261,026						
570,830	443,740	1,014,570	9,915,350	10,728,869						
7,719,380	**7,023,990**	**14,743,370**	**181,177,790**	**194,380,458**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,521,650	617,250	17,180,600	1,392,600	35,788,210	41,630	231,440	36,061,280	21,712,100	57,773,380
ME	2,103,560	3,021,980	0	295,440	20,122,420	4,970	135,010	20,262,900	5,420,980	25,683,280
MA	1,759,740	880,530	5,597,860	3,175,160	40,797,870	29,080	426,490	41,253,440	11,413,290	52,666,730
NH	673,360	2,060,490	9,912,880	1,202,940	8,375,260	23,360	6,290	8,404,910	13,849,670	22,254,580
RI	90,240	0	0	0	12,782,700	11,530	0	12,794,230	90,240	12,884,470
VT	570,830	443,740	5,014,570	0	3,817,190	69,020	0	3,886,210	6,029,140	9,915,350
Total	**7,719,380**	**7,023,990**	**37,705,910**	**6,066,140**	**121,683,550**	**179,590**	**799,230**	**122,662,370**	**58,515,420**	**181,177,790**

Summary of Results: 2030 Low Stress Scenario, DSM-Focus Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSR* ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
61.1	58.8	59%	8,469	43,837,798	57,366,012	-13,528,171	9,898	12,147	-2,249	4.6	9.4	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
286	428	93	1,664	403	336	2	-773	-123	232	2,548

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,680	543	-22	-51	9	11	66	3,722	8.49	172	336	509	1.16	4,230	9.65

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,979	413	2,392	5.46	172	336	509	1.16	2,901	6.62

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.2%	4,936

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
38,914,559	49,366,321	250,471,647	62%	123,619,994	173,274,656	841,651,173

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emission - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,523,172	2,258	3,806	16,828,585	9,554	4,866
ME	9,881,429	1,707	1,900	9,887,211	2,153	1,913
MA	21,433,419	21,041	8,069	21,417,425	21,013	8,061
NH	4,942,347	7,724	2,516	4,960,755	7,677	2,511
RI	4,712,627	41	814	4,715,806	45	815
VT	2,236,928	40	290	2,251,920	43	294
Total	**61,729,923**	**32,811**	**17,295**	**60,061,706**	**40,485**	**18,460**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,521,660	617,470	3,139,130	57,365,720	43,837,798	23%	20%	3%	1,253,190	1,273,260	252,002,410
2,103,760	3,022,430	5,126,190	25,723,730	17,993,303						
1,759,900	915,280	2,675,180	51,420,630	85,671,406						
673,620	2,059,380	2,733,000	22,357,110	16,767,908						
90,320	0	90,320	11,174,840	16,261,026						
570,770	443,480	1,014,250	10,009,390	10,725,869						
7,720,030	**7,058,040**	**14,778,070**	**178,051,420**	**191,261,300**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,521,660	617,470	17,180,600	1,412,530	35,294,390	26,030	313,040	35,633,460	21,732,260	57,365,720
ME	2,103,760	3,022,430	0	293,050	20,180,190	4,990	119,310	20,304,490	5,419,240	25,723,730
MA	1,759,900	915,280	5,597,860	3,372,410	39,275,940	29,240	470,000	39,775,180	11,645,450	51,420,630
NH	673,620	2,059,380	9,912,880	1,227,620	8,454,100	21,300	8,210	8,483,610	13,873,500	22,357,110
RI	90,320	0	0	0	11,065,720	18,800	0	11,084,520	90,320	11,174,840
VT	570,770	443,480	5,014,570	0	3,911,520	69,050	0	3,980,570	6,028,820	10,009,390
Total	**7,720,030**	**7,058,040**	**37,705,910**	**6,305,610**	**118,181,860**	**169,410**	**910,560**	**119,261,830**	**58,789,590**	**178,051,420**

Summary of Results: 2030 Low Stress Scenario, Nuclear Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
60.1	56.4	58%	9,196	46,957,157	62,644,881	-15,687,680	10,722	13,047	-2,324	5.3	5.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
720	542	99	1,577	354	360	0	-845	-148	156	2,825

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,820	684	-49	-68	8	18	61	3,996	8.51	116	360	476	1.01	4,472	9.52

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
2,309	413	2,722	5.80	116	360	476	1.01		3,198	6.81

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
34,255,381	44,346,037	221,160,619	50%	116,883,099	166,190,997	799,941,659

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,469,825	1,793	3,375	14,882,923	8,159	4,230
ME	9,844,279	1,783	1,911	9,449,641	2,227	1,923
MA	20,722,736	19,299	7,564	20,709,398	19,267	7,555
NH	4,890,298	7,565	2,472	4,910,527	7,538	2,472
RI	4,575,466	40	790	4,575,466	40	790
VT	2,118,924	37	270	2,132,985	41	274
Total	**58,621,529**	**30,517**	**16,182**	**57,060,941**	**37,271**	**17,244**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,489,300	615,340	3,104,640	62,644,580	46,957,157	23%	20%	3%	1,234,170	1,259,900	277,009,491
2,101,570	3,023,240	5,124,810	25,617,260	17,993,893						
1,758,770	869,110	2,627,880	50,069,880	85,671,806						
672,190	2,060,380	2,732,570	22,268,150	16,767,905						
89,870	0	89,870	10,863,760	16,261,026						
569,660	443,440	1,013,100	9,726,396	10,728,869						
7,681,360	**7,011,510**	**14,692,870**	**181,190,026**	**194,380,658**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,489,300	615,340	26,863,930	1,254,450	31,187,840	39,600	194,120	31,421,560	31,223,020	62,644,580
ME	2,101,570	3,023,240	0	307,020	20,061,910	4,620	118,900	20,185,430	5,431,830	25,617,260
MA	1,758,770	869,110	5,597,860	3,066,560	38,321,320	28,740	427,520	38,777,580	11,292,300	50,069,880
NH	672,190	2,060,380	9,912,880	1,206,620	8,392,250	22,540	1,290	8,416,080	13,852,070	22,268,150
RI	89,870	0	0	0	10,773,890	0	0	10,773,890	89,870	10,863,760
VT	569,660	443,440	5,014,570	0	3,633,490	64,836	0	3,698,726	6,027,670	9,726,396
Total	**7,681,360**	**7,011,510**	**47,389,240**	**5,834,650**	**112,371,100**	**160,336**	**741,830**	**113,273,266**	**67,916,760**	**181,190,026**

Summary of Results: 2030 Low Stress Scenario, Coal Solution

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
60.1	56.4	58%	9,196	46,957,157	62,644,881	-15,687,681	10,722	13,047	-2,324	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
505	475	135	1,742	574	360	0	-845	-148	156	2,954

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,820	684	-49	-68	8	18	61	3,996	8.51	116	360	476	1.01	4,472	9.52

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,438	413	2,851	6.07	116	360	476	1.01	3,328	7.09

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
34,255,381	44,346,037	221,160,619	50%	116,883,099	166,190,997	799,941,659

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	24,603,437	1,793	3,275	23,016,536	8,159	4,230
ME	9,844,279	1,783	1,811	9,849,641	2,227	1,923
MA	20,722,736	19,299	7,564	20,709,398	19,267	7,555
NH	4,890,298	7,565	2,472	4,910,527	7,538	2,472
RI	4,575,466	40	790	4,575,466	40	790
VT	2,118,924	37	270	2,132,985	41	274
Total	**66,755,141**	**30,517**	**16,182**	**65,194,553**	**37,271**	**17,244**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,489,300	615,340	3,104,640	62,644,580	46,957,157	23%	20%	3%	1,234,170	1,259,900	277,009,491
2,101,570	3,023,240	5,124,810	25,617,260	17,993,893						
1,758,770	869,110	2,627,880	50,069,880	85,671,806						
672,190	2,060,380	2,732,570	22,268,150	16,767,904						
89,870	0	89,870	10,863,760	16,261,026						
569,660	443,440	1,013,100	9,726,396	10,728,869						
7,681,360	**7,011,510**	**14,692,870**	**181,190,026**	**194,380,658**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,489,300	615,340	17,180,600	10,550,447	31,187,840	39,600	194,120	31,421,560	30,835,687	62,257,247
ME	2,101,570	3,023,240	0	307,020	20,061,910	4,620	118,900	20,185,430	5,431,830	25,617,260
MA	1,758,770	869,110	5,597,860	3,066,560	38,321,320	28,740	427,520	38,777,580	11,292,300	50,069,880
NH	672,190	2,060,380	9,912,880	1,266,620	8,392,250	22,540	1,260	8,416,050	13,852,070	22,268,150
RI	89,870	0	0	0	10,773,890	0	0	10,773,890	89,870	10,863,760
VT	569,660	443,440	5,014,570	0	3,633,890	64,836	0	3,698,726	6,027,670	9,726,396
Total	**7,681,360**	**7,011,510**	**37,705,910**	**15,130,647**	**112,371,100**	**160,336**	**741,800**	**113,273,266**	**67,529,427**	**180,802,692**

Summary of Results: 2013 Current Trends Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
72.9	70.4	57%	7,229	36,164,316	36,268,586	-104,265	8,429	8,251	178	3.7	10.3	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	40	1,024	63	231	148	-132	8	103	1,799

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,636	376	-5	-64	21	3	72	3,495	9.67	121	231	352	0.97	3,847	10.64

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,465	413	1,879	5.19	121	231	352	0.97	2,231	6.17

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.2%	2,292

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,239,790	17,267,871	83,323,561	32%	58,080,687	89,650,436	401,144,262

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,524,198	9,277	4,759	9,963,239	25,047	7,094
ME	6,413,381	4,280	1,774	6,414,682	4,718	1,884
MA	22,101,927	74,359	19,945	22,078,998	74,347	19,938
NH	7,837,752	25,580	6,956	7,936,312	25,582	6,973
RI	2,964,680	26	512	2,964,679	26	512
VT	553,255	2	2	560,464	2	3
Total	49,695,193	113,523	33,948	49,918,374	129,722	36,403

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,450	616,210	3,001,660	36,268,280	36,164,316	13%	10%	3%	1,132,180	1,258,070	121,949,520
2,094,200	3,020,800	5,115,000	16,525,440	13,086,492						
1,761,790	920,680	2,682,470	40,302,111	63,382,777						
709,100	2,025,300	2,734,400	25,074,820	11,203,706						
94,260	0	94,260	7,064,520	12,184,916						
539,320	439,350	978,670	5,966,728	7,873,275						
7,584,120	7,022,340	14,606,460	131,201,898	144,395,481						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,385,450	616,210	17,091,560	3,375,380	11,539,600	35,750	1,224,310	12,799,660	23,468,620	36,268,280
ME	2,094,200	3,020,800	0	657,510	10,484,310	1,350	267,270	10,752,930	5,772,510	16,525,440
MA	1,761,790	920,680	5,597,860	12,691,790	18,719,320	27,821	1,182,860	19,930,001	20,372,110	40,302,111
NH	709,100	2,025,300	10,000,470	4,024,100	8,201,170	2,590	111,490	8,315,450	16,759,370	25,074,820
RI	94,260	0	0	0	6,970,260	0	0	6,970,260	94,260	7,064,520
VT	539,320	439,350	4,969,930	0	12,410	5,718	0	18,128	5,948,600	5,966,728
Total	7,584,120	7,022,340	37,660,240	20,148,770	55,927,070	73,228	2,786,130	58,786,428	72,415,470	131,201,898

Summary of Results: 2013 Current Trends Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
72.1	69.7	58%	6,888	35,070,158	36,048,092	-977,920	8,032	8,251	-219	4.1	9.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	39	1,009	62	224	114	-163	-11	155	1,743

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,527	392	-3	-62	21	3	70	3,398	9.87	300	224	524	1.49	3,913	11.16

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
1,365	413	1,778	5.07	300	224	524	1.49		2,301	6.56

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.6%	2,721

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,971,092	17,171,667	82,676,108	32%	56,704,057	88,516,583	393,417,693

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	9,690,130	9,039	4,663	9,819,856	24,662	6,966
ME	6,404,965	4,242	1,765	6,406,126	4,681	1,875
MA	21,877,447	74,237	19,882	21,952,594	74,223	19,873
NH	7,824,363	25,572	6,952	7,827,896	25,573	6,953
RI	2,873,815	25	496	2,873,815	25	496
VT	552,223	1	1	557,436	1	2
Total	49,222,945	113,116	33,759	49,338,134	129,164	36,185

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,170	615,720	3,000,890	36,047,700	35,070,158	13%	10%	3%	1,132,020	1,257,940	116,586,260
2,094,040	3,020,440	5,114,480	16,514,680	13,086,492						
1,761,600	900,860	2,662,460	39,796,110	63,862,777						
709,060	2,024,160	2,733,220	24,920,830	11,203,706						
94,230	0	94,230	6,860,130	12,184,916						
539,250	439,010	978,260	5,965,680	7,873,275						
7,583,350	7,000,190	14,583,540	130,103,210	143,381,323						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,385,170	615,720	17,091,580	3,356,220	11,407,750	29,840	1,161,500	12,599,090	23,448,690	36,047,780
ME	2,094,040	3,020,440	0	657,600	10,483,120	1,210	258,270	10,742,600	5,772,080	16,514,680
MA	1,761,600	900,860	5,597,860	12,111,200	18,275,260	25,030	1,124,300	19,424,590	20,371,520	39,796,110
NH	709,060	2,024,160	10,000,870	4,027,750	8,051,090	1,930	103,970	8,156,990	16,763,840	24,920,830
RI	94,230	0	0	0	6,765,900	0	0	6,765,900	94,230	6,860,130
VT	539,250	439,010	4,969,930	0	12,270	3,220	0	15,490	5,948,190	5,963,680
Total	7,583,350	7,000,190	37,660,240	20,152,770	54,997,390	61,230	2,648,040	57,706,660	72,396,550	130,103,210

Summary of Results: 2018 Current Trends Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss - grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
78.7	75.9	57%	7,441	36,952,178	37,745,834	-793,649	8,677	8,550	127	3.1	10.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
28	323	42	1,123	148	324	143	-180	5	156	2,112

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,908	318	-12	-67	21	4	77	3,736	10.11	116	324	440	1.19	4,175	11.30

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
1,632	413	2,045	5.54	116	324	440	1.19		2,485	6.73

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	2,510

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation		ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)		(MMBtu)		(MMBtu)
14,820,498	20,068,556	97,684,926	36%		66,768,464	97,544,692	453,255,001

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,867,567	7,375	4,304	10,205,999	22,551	6,509
ME	7,814,486	3,959	1,954	7,815,792	4,395	2,063
MA	22,110,124	67,518	18,446	22,091,225	67,541	18,447
NH	7,875,145	27,008	7,279	7,878,313	26,932	7,272
RI	2,704,570	23	467	2,704,570	23	467
VT	511,363	1	2	517,101	2	3
Total	52,883,255	105,885	32,451	51,213,000	121,485	34,861

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,560	616,660	2,996,220	37,745,470	36,952,178	20%	17%	3%	1,211,590	1,172,970	222,154,674
2,011,480	3,020,840	5,032,320	20,131,760	13,807,015						
1,782,040	923,560	2,705,600	42,133,120	66,657,772						
697,520	2,026,500	2,724,020	24,670,680	12,047,403						
95,280	0	95,280	6,476,750	12,665,021						
494,600	439,740	934,340	6,027,920	8,272,718						
7,460,480	7,027,300	14,487,780	137,185,700	150,402,587						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,560	616,660	17,150,850	3,355,590	13,521,030	41,580	649,870	14,212,760	23,532,690	37,745,470
ME	2,011,480	3,020,840	0	666,240	14,255,310	1,340	176,550	14,433,200	5,698,560	20,131,760
MA	1,782,040	923,560	5,597,860	11,344,710	21,834,770	38,120	412,060	22,284,950	19,848,170	42,133,120
NH	697,520	2,026,500	10,000,870	4,320,690	7,604,160	3,290	17,650	7,625,100	17,045,580	24,670,680
RI	95,280	0	0	0	6,381,470	0	0	6,381,470	95,280	6,476,750
VT	494,600	439,740	5,074,090	0	14,000	5,490	0	19,490	6,008,430	6,027,920
Total	7,460,480	7,027,300	37,823,708	19,687,230	63,610,740	90,120	1,456,130	65,156,990	72,028,710	137,185,700

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.6	75.2	57%	6,790	34,173,972	35,589,416	-1,415,432	7,917	8,251	-334	3.2	10.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	998	136	299	104	-196	-13	303	1,982

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,651	308	-2	-67	21	3	76	3,438	10.06	172	299	472	1.38	3,910	11.44

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
1,380	413	1,793	5.25	172	299	472	1.38		2,265	6.63

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.1%	3,032

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,210,860	17,179,082	82,690,167	32%	62,835,533	93,250,843	432,947,253

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,001,724	7,365	4,144	9,313,430	22,590	6,446
ME	7,148,869	4,047	1,859	7,149,810	4,482	1,968
MA	22,325,232	67,923	18,548	22,305,678	67,838	18,548
NH	8,143,845	27,387	7,407	8,144,423	27,317	7,392
RI	2,718,854	23	469	2,718,854	23	469
VT	509,355	1	1	514,671	1	2
Total	51,847,918	106,646	32,428	50,146,816	122,163	34,826

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,560	616,290	2,995,850	35,589,040	34,173,972	20%	17%	3%	1,211,390	1,172,970	201,461,948
2,011,630	3,021,220	5,032,850	18,458,960	13,807,015						
1,782,070	925,760	2,707,830	42,600,680	66,657,772						
697,550	2,024,900	2,722,450	25,224,580	12,047,603						
95,340	0	95,340	6,510,620	12,665,021						
494,600	439,460	934,060	6,025,540	8,272,718						
7,460,750	7,027,630	14,488,380	134,409,420	147,624,581						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,560	616,290	17,180,850	3,375,220	11,390,010	31,990	615,050	12,037,090	23,551,950	35,589,040
ME	2,011,630	3,021,220	0	667,120	12,561,180	970	196,840	12,758,990	5,699,970	18,458,960
MA	1,782,070	925,760	5,597,860	11,357,910	22,234,640	28,860	673,580	22,937,080	19,663,600	42,600,680
NH	697,550	2,024,900	10,000,870	4,345,240	8,093,280	2,150	60,590	8,156,020	17,068,560	25,224,580
RI	95,340	0	0	0	6,415,280	0	0	6,415,280	95,340	6,510,620
VT	494,600	439,460	5,074,090	0	14,060	3,330	0	17,390	6,008,150	6,025,540
Total	7,460,750	7,027,630	37,853,708	19,745,490	60,708,450	67,300	1,546,100	62,321,858	72,087,570	134,409,420

Summary of Results: 2018 Current Trends Scenario, Nuclear Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
77.4	73.7	57%	7,441	36,952,178	44,827,449	-7,875,236	8,677	9,451	-774	3.5	10.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
593	437	53	1,062	132	324	22	-558	-33	156	2,180

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,861	368	-10	-41	24	3	73	3,726	10.08	116	324	440	1.19	4,166	11.27

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,700	413	2,113	5.72	116	324	440	1.19	2,553	6.91

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,410

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,349,977	16,807,251	79,821,878	25%	57,787,961	85,044,189	386,866,077

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,727,451	7,067	4,030	9,864,365	22,126	6,324
ME	6,214,268	4,017	1,692	6,216,101	4,453	1,802
MA	20,638,355	66,238	17,911	20,620,753	66,256	17,912
NH	8,059,552	26,965	7,299	8,058,809	26,879	7,281
RI	2,565,743	22	443	2,565,743	22	443
VT	310,127	1	1	515,417	2	2
Total	48,715,496	104,310	31,378	47,061,188	119,738	33,765

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,420	616,190	2,995,610	44,827,100	36,952,178	20%	17%	3%	1,211,320	1,172,890	222,157,741
2,011,300	3,021,910	5,033,210	16,150,320	13,807,015						
1,781,910	946,430	2,728,340	38,914,460	66,657,772						
697,360	2,025,410	2,722,770	25,124,890	12,047,603						
95,270	0	95,270	6,146,440	12,665,021						
494,540	439,510	934,050	6,026,070	9,272,718						
7,459,800	7,049,450	14,509,250	137,189,680	150,402,587						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,420	616,190	26,864,210	3,315,050	11,000,790	31,930	619,510	11,652,230	33,174,870	44,827,100
ME	2,011,300	3,021,910	0	657,670	10,253,820	1,690	203,730	10,459,440	5,690,880	16,150,320
MA	1,781,910	946,430	5,597,860	11,131,310	18,813,850	24,970	618,130	19,456,950	19,457,510	38,914,460
NH	697,360	2,025,410	10,000,870	4,270,920	8,061,100	2,550	66,680	8,130,330	16,994,560	25,124,890
RI	95,270	0	0	0	6,051,570	0	0	6,051,570	95,270	6,146,840
VT	494,540	439,510	5,074,090	0	13,890	4,040	0	17,930	6,008,140	6,026,070
Total	7,459,800	7,049,450	47,537,030	19,374,950	54,195,020	65,380	1,508,050	55,768,450	81,421,230	137,189,680

Summary of Results: 2018 Current Trends Scenario, Coal Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
72.4	73.7	57%	7,441	36,952,178	44,827,449	-7,875,236	8,677	9,451	-774	3.5	10.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
302	371	89	1,234	259	324	22	-558	-33	156	2,167

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,861	368	-10	-81	24	3	73	3,726	10.08	116	324	440	1.19	4,166	11.27

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,666	413	2,100	5.68	116	324	440	1.19	2,540	6.87

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,410

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,749,977	16,807,251	79,821,878	25%	57,787,961	85,944,189	386,866,077

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,861,083	7,067	4,030	17,217,977	22,126	6,324
ME	6,214,268	4,017	1,692	6,216,101	4,453	1,802
MA	20,638,355	66,238	17,911	20,620,753	66,256	17,912
NH	8,059,552	26,965	7,299	8,058,809	26,879	7,281
RI	2,565,743	22	443	2,565,743	22	443
VT	510,127	1	1	515,417	2	2
Total	56,849,108	104,310	31,378	55,194,800	119,738	33,765

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,420	616,190	2,995,610	44,827,100	36,952,178	20%	17%	3%	1,211,320	1,172,890	222,157,741
2,011,300	3,021,910	5,033,210	16,150,320	13,807,015						
1,781,910	946,430	2,728,340	38,914,460	66,657,772						
697,360	2,025,410	2,722,770	25,124,890	12,047,803						
95,270	0	95,270	6,146,840	12,665,021						
494,540	439,510	934,050	8,028,070	8,272,718						
7,459,800	7,049,450	14,509,250	137,189,680	150,402,507						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,420	616,190	17,150,880	12,611,047	11,600,790	31,930	619,510	11,652,230	32,767,537	44,419,767
ME	2,011,300	3,021,910	0	657,670	10,253,920	1,490	203,730	10,459,440	5,690,860	16,150,320
MA	1,781,910	946,430	5,597,860	11,131,310	18,813,850	24,970	618,130	19,456,950	19,457,510	38,914,460
NH	697,360	2,025,410	10,000,870	4,270,920	8,051,100	2,550	66,680	8,120,330	16,994,560	25,124,890
RI	95,270	0	0	0	6,051,570	0	0	6,051,570	95,270	6,146,840
VT	494,540	439,510	5,074,090	0	13,890	4,040	0	17,930	6,008,140	6,026,070
Total	7,459,800	7,049,450	37,823,708	28,670,947	54,195,020	65,380	1,508,050	55,748,450	81,033,897	136,882,347

Summary of Results: 2030 Current Trends Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
86.9	82.8	56%	8,424	41,549,275	50,227,301	-8,677,988	9,823	10,947	-1,124	4.3	9.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
244	392	73	1,942	368	319	20	-698	-59	156	2,757

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,609	511	-42	-72	16	9	68	4,713	11.34	116	319	435	1.05	5,148	12.39

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,292	413	2,696	6.49	116	319	435	1.05	3,130	7.53

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,771

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
29,422,859	40,061,332	188,959,762	53%	95,370,659	143,498,808	621,803,301

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,754,694	6,390	4,805	15,039,065	20,099	6,896
ME	9,393,874	3,696	2,158	9,399,283	4,142	2,270
MA	23,164,737	63,567	17,764	22,864,875	62,313	17,479
NH	7,478,039	26,110	7,013	7,481,263	26,026	6,996
RI	2,997,363	26	518	2,997,363	26	518
VT	1,428,970	12	147	1,434,111	14	148
Total	61,225,677	99,801	32,405	59,415,760	112,620	34,307

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	617,860	3,141,510	50,227,020	41,549,275	23%	20%	3%	1,254,600	1,273,850	235,294,330
2,105,950	3,022,870	5,128,820	24,081,120	16,096,049						
1,761,170	914,330	2,675,500	45,909,368	76,092,263						
674,640	2,053,670	2,728,310	23,863,180	14,892,841						
90,730	0	90,730	7,236,470	14,386,939						
571,520	443,200	1,014,720	8,098,650	9,600,632						
7,727,660	7,051,930	14,779,590	159,415,808	172,617,999						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,650	617,860	17,189,600	3,299,360	26,453,340	34,420	117,790	26,605,550	23,621,470	50,227,020
ME	2,105,950	3,022,870	0	700,200	18,179,940	1,430	70,730	18,252,100	5,829,020	24,081,120
MA	1,761,170	914,330	5,597,860	10,843,170	26,654,720	15,678	122,440	26,792,838	19,116,530	45,909,368
NH	674,640	2,053,670	9,912,800	4,195,190	7,018,440	8,360	0	7,026,800	16,836,380	23,863,180
RI	90,730	0	0	0	7,145,740	0	0	7,145,740	90,730	7,236,470
VT	571,520	443,200	3,014,570	0	2,054,570	14,790	0	2,069,360	6,029,290	8,098,650
Total	7,727,660	7,051,930	35,705,910	19,037,920	87,506,750	74,678	310,960	87,892,388	71,523,420	159,415,808

Summary of Results: 2030 Current Trends Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
85.6	82.4	57%	7,687	38,425,488	49,747,584	-11,322,054	8,963	10,647	-1,684	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	384	71	1,908	361	295	6	-905	-90	232	2,482

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,289	480	-17	-68	16	9	67	4,343	11.30	172	295	467	1.22	4,810	12.52

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,955	413	2,369	6.16	172	295	467	1.22	2,836	7.38

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.9%	4,400

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,593,809	38,850,647	185,425,426	52%	91,066,123	138,156,173	599,652,576

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,474,711	6,030	4,667	14,772,209	19,771	6,778
ME	9,328,465	3,687	2,145	9,330,622	4,133	2,257
MA	22,313,032	62,530	17,388	22,213,752	61,246	17,097
NH	7,436,023	25,920	6,964	7,438,872	25,822	6,944
RI	2,679,553	23	463	2,679,553	23	463
VT	1,423,985	13	146	1,420,978	14	147
Total	59,655,669	98,203	31,792	57,863,985	111,089	33,685

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	617,880	3,141,530	49,747,290	38,425,488	23%	20%	3%	1,254,600	1,273,850	214,458,531
2,105,910	3,023,580	5,129,490	23,916,230	16,096,049						
1,761,170	942,240	2,703,410	44,240,840	76,092,263						
674,640	2,056,060	2,730,700	23,809,450	14,892,841						
90,730	0	90,730	6,491,500	14,386,939						
571,520	443,360	1,014,880	8,084,370	9,600,632						
7,727,620	7,083,120	14,810,740	156,289,720	169,494,212						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,650	617,880	17,180,600	3,248,920	26,027,500	25,850	122,890	26,176,240	23,571,050	49,747,290
ME	2,105,910	3,023,580	0	700,340	18,015,700	2,170	68,290	18,086,160	5,830,070	23,916,230
MA	1,761,170	942,240	5,547,860	10,662,320	25,115,610	18,940	142,740	25,277,290	18,963,590	44,240,880
NH	674,640	2,056,060	9,912,000	4,162,220	6,993,030	9,920	0	7,002,950	16,805,500	23,809,450
RI	90,730	0	0	0	6,400,770	0	0	6,400,770	90,730	6,491,500
VT	571,520	443,360	5,014,570	0	2,039,170	15,750	0	2,054,920	6,029,450	8,084,370
Total	7,727,620	7,083,120	37,705,910	18,774,040	84,592,580	72,630	333,920	84,999,830	71,290,690	156,289,720

Summary of Results: 2030 Current Trends Scenario, Nuclear Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
84.2	79.5	56%	8,424	41,549,275	57,206,942	-15,657,624	9,823	11,847	-2,024	5.1	8.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
803	507	83	1,563	336	319	1	-1,195	-123	156	2,751

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,497	597	-43	-85	15	12	63	4,663	11.22	116	319	435	1.05	5,098	12.27

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,276	413	2,689	6.47	116	319	435	1.05	3,124	7.52

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	4,670

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,217,480	36,558,047	170,096,140	42%	83,771,104	130,656,088	554,652,704

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	15,369,050	5,776	4,432	15,799,192	19,245	6,496
ME	9,256,085	3,669	2,128	9,258,473	4,116	2,240
MA	21,653,973	62,021	17,164	21,560,942	60,839	16,896
NH	7,373,990	25,891	6,947	7,377,195	25,800	6,929
RI	2,491,354	22	430	2,491,354	22	430
VT	600,247	5	4	605,209	6	5
Total	**56,744,698**	**97,384**	**31,105**	**55,492,363**	**110,027**	**32,996**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,150	617,540	3,125,690	57,206,680	41,549,275	23%	20%	3%	1,244,800	1,268,060	235,618,494
2,105,900	3,023,110	5,129,010	23,737,120	16,096,049						
1,761,160	892,190	2,653,350	42,710,910	76,092,263						
674,640	2,053,340	2,727,980	23,661,560	14,892,841						
90,680	0	90,680	6,043,390	14,386,939						
571,470	443,660	1,015,130	6,055,760	9,600,632						
7,712,800	**7,029,840**	**14,741,840**	**159,415,420**	**172,617,999**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,150	617,540	26,863,930	3,174,560	23,902,340	35,230	104,890	24,042,500	33,164,180	57,206,680
ME	2,105,900	3,023,110	0	696,340	17,440,010	2,410	69,350	17,911,770	5,825,350	23,737,120
MA	1,761,160	892,190	5,597,860	10,599,110	23,715,200	18,100	127,290	23,860,590	18,850,320	42,710,910
NH	674,640	2,053,340	9,912,000	4,157,200	6,854,590	8,910	0	6,863,500	16,798,060	23,661,560
RI	90,680	0	0	0	5,952,710	0	0	5,952,710	90,680	6,043,390
VT	571,470	443,660	5,014,570	0	11,660	14,190	0	26,060	6,029,700	6,055,760
Total	**7,712,800**	**7,029,840**	**47,389,248**	**18,627,210**	**78,276,770**	**78,830**	**301,530**	**78,657,130**	**80,758,290**	**159,415,420**

Summary of Results: 2030 Current Trends Scenario, Coal Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
84.2	79.5	56%	8,424	41,549,275	57,206,942	-15,657,624	9,423	11,847	-2,024	5.1	8.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
522	441	119	2,038	556	319	1	-1,195	-123	156	2,833

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,497	597	-43	-85	15	12	63	4,663	11.22	116	319	435	1.05	5,098	12.27

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,359	413	2,772	6.67	116	319	435	1.05	3,207	7.72

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	4,620

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,217,480	36,558,047	170,096,140	42%	83,771,104	130,656,088	554,652,704

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	23,502,662	5,776	4,432	21,932,804	19,245	6,496
ME	9,256,085	3,669	2,128	9,258,473	4,116	2,240
MA	21,653,973	62,021	17,164	21,560,942	60,839	16,896
NH	7,373,980	25,891	6,947	7,377,193	25,800	6,929
RI	2,491,354	22	430	2,491,354	22	430
VT	600,247	5	4	605,209	6	5
Total	64,878,302	97,384	31,105	63,225,975	110,027	32,996

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,508,150	617,540	3,125,690	57,206,860	41,549,275	23%	20%	3%	1,244,880	1,268,060	235,618,494
2,105,900	3,023,110	5,129,010	23,737,120	16,096,049						
1,761,160	892,190	2,653,350	42,710,910	76,092,263						
674,640	2,053,340	2,727,980	23,661,560	14,892,841						
90,680	0	90,680	6,043,390	14,386,939						
571,470	443,660	1,015,130	6,055,760	9,600,632						
7,712,000	7,029,840	14,741,840	159,415,420	172,617,999						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,508,150	617,540	17,180,600	12,470,557	23,902,380	35,230	104,890	24,042,500	32,776,847	56,819,347
ME	2,105,900	3,023,110	0	696,340	17,840,010	2,410	69,350	17,911,770	5,825,350	23,737,120
MA	1,761,160	892,190	5,597,860	10,599,110	23,715,200	18,100	127,290	23,860,590	18,850,320	42,710,910
NH	674,640	2,053,340	9,912,000	4,157,290	6,854,590	8,910	0	6,863,500	16,798,060	23,661,560
RI	90,680	0	0	0	5,952,710	0	0	5,952,710	90,680	6,043,390
VT	571,470	443,660	5,014,570	0	11,880	14,180	0	26,060	6,029,700	6,055,760
Total	7,712,000	7,029,840	37,705,910	27,923,287	78,276,770	78,830	301,530	78,657,130	80,370,957	159,028,087

Summary of Results: 2013 Strict Climate Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.06 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
87.6	84.5	56%	7,187	35,522,074	35,740,197	-218,124	8,380	8,251	129	2.3	11.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	38	1,054	237	227	182	-169	4	103	1,990

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION $VC COST + 15% PREMIUM	AVERAGE GENERATION $VC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,112	236	-4	-76	24	3	82	3,883	10.93	121	227	348	0.98	4,231	11.91

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION $VC COST	AVERAGE GENERATION $VC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,661	413	2,074	5.84	121	227	348	0.98	2,422	6.82

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.1%	2,378

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,672,431	17,367,787	83,033,673	32%	57,658,278	90,108,780	400,276,934

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	11,314,655	6,923	4,109	9,448,901	22,142	6,411
ME	6,373,770	4,039	1,715	6,375,855	4,478	1,825
MA	19,997,653	61,992	16,660	18,991,300	62,018	16,865
NH	7,215,360	21,889	6,034	7,221,551	21,891	6,036
RI	2,964,112	26	515	2,964,112	26	515
VT	553,610	1	1	560,207	2	3
Total	48,239,181	94,871	29,235	46,581,586	110,757	31,655

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,385,430	616,800	3,002,230	35,739,000	35,522,074	13%	10%	3%	1,132,160	1,258,070	118,797,796
2,094,210	3,020,750	5,114,960	16,496,910	12,747,271						
1,761,770	1,004,030	2,765,800	38,463,925	62,513,186						
709,130	2,025,980	2,735,110	24,385,360	10,961,724						
94,240	0	94,240	7,116,030	11,950,422						
539,300	439,700	979,000	5,967,850	7,672,083						
7,584,080	7,107,260	14,691,340	128,172,975	141,366,760						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,385,430	616,800	17,091,580	3,028,030	11,461,590	37,740	1,118,710	12,618,040	23,121,840	35,739,880
ME	2,094,210	3,020,750	0	639,180	10,507,570	2,170	233,030	10,742,770	5,754,140	16,496,910
MA	1,761,770	1,004,030	5,597,860	10,277,480	18,856,640	35,785	930,360	19,822,785	18,641,140	38,463,925
NH	709,130	2,025,980	10,000,870	3,448,160	8,092,750	4,400	106,890	8,204,040	16,184,340	24,388,380
RI	94,240	0	0	0	7,021,790	0	0	7,021,790	94,240	7,116,030
VT	539,300	439,700	4,969,930	0	14,200	4,620	0	18,820	5,948,930	5,967,850
Total	7,584,080	7,107,260	37,660,240	17,393,050	55,954,640	84,715	2,388,990	58,428,345	69,744,630	128,172,975

Summary of Results: 2013 Strict Climate Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
86.7	83.7	57%	6,871	34,429,862	35,483,618	-1,053,740	8,011	8,251	-240	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	1,036	232	220	141	-203	-8	155	1,923

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,984	280	-3	-73	23	4	78	3,796	11.00	300	220	519	1.51	4,316	12.51

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,549	413	1,962	5.70	300	220	519	1.51	2,481	7.21

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
20.4%	2,807

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,488,020	17,150,364	81,935,001	32%	56,195,346	84,872,851	393,589,552

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,920,551	6,543	1,971	9,263,420	21,778	6,258
ME	6,310,410	3,955	1,687	6,312,281	4,394	1,797
MA	19,751,545	61,534	16,717	19,744,612	61,555	16,720
NH	7,173,956	21,780	6,003	7,179,136	21,781	6,004
RI	2,892,928	25	500	2,892,928	25	500
VT	552,776	0	1	558,827	2	2
Total	47,602,167	93,838	28,877	45,951,204	109,535	31,281

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,430	616,460	3,001,890	35,483,350	34,429,962	13%	10%	3%	1,132,160	1,258,070	113,436,233
2,094,240	3,020,750	5,114,990	16,364,340	12,747,271						
1,761,770	1,032,280	2,794,050	38,043,329	62,513,186						
709,130	2,024,820	2,733,950	24,315,010	10,961,724						
94,260	0	94,260	6,909,180	11,950,422						
539,300	439,470	978,770	5,966,040	7,672,083						
7,584,130	7,133,780	14,717,910	127,081,249	140,274,648						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,430	616,460	17,091,560	2,994,320	11,325,360	31,240	1,038,960	12,395,560	23,087,790	35,483,350
ME	2,094,240	3,020,750	0	635,770	10,393,720	1,910	217,900	10,613,580	5,750,760	16,364,340
MA	1,761,770	1,032,280	5,597,860	10,204,220	18,492,470	28,889	925,840	19,447,199	18,596,130	38,043,329
NH	709,130	2,024,820	10,060,870	3,439,030	8,012,310	3,700	95,150	8,141,360	16,173,650	24,315,010
RI	94,260	0	0	0	6,814,920	0	0	6,814,920	94,260	6,909,180
VT	539,300	439,470	4,969,930	0	13,650	3,690	0	17,340	5,948,700	5,966,040
Total	7,584,130	7,133,780	37,660,248	17,273,340	55,682,440	69,469	2,277,850	57,429,759	69,651,490	127,081,249

Summary of Results: 2018 Strict Climate Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.4	88.1	56%	7,381	35,980,213	37,368,261	-1,388,038	8,606	8,550	56	2.8	11.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
28	323	41	1,170	302	315	151	-239	2	156	2,250

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,288	285	-10	-76	22	4	79	4,131	11.48	116	315	431	1.20	4,563	12.68

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,779	413	2,192	6.09	116	315	431	1.20	2,623	7.29

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.8%	2,640

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
14,232,841	19,945,218	96,261,931	36%	62,879,958	95,560,245	441,183,895

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,487,299	5,472	3,005	9,839,134	20,948	6,168
ME	7,037,583	3,823	1,790	7,038,749	4,259	1,899
MA	20,359,742	57,433	15,919	20,364,654	57,473	15,928
NH	6,990,250	21,006	5,800	6,998,011	21,007	5,802
RI	2,731,240	24	472	2,731,240	24	472
VT	508,872	0	1	516,048	2	2
Total	**49,114,966**	**87,758**	**27,787**	**47,487,839**	**103,612**	**30,273**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,560	616,940	2,996,500	37,367,940	35,980,213	20%	17%	3%	1,211,390	1,172,970	214,915,216
2,011,630	3,021,830	5,033,460	18,240,660	13,300,363						
1,782,070	955,140	2,737,210	40,515,020	64,675,456						
697,550	2,026,960	2,724,510	24,047,410	11,688,543						
95,340	0	95,340	6,535,610	12,333,051						
494,600	440,060	934,660	6,027,720	7,972,790						
7,460,750	**7,060,930**	**14,521,680**	**131,734,360**	**145,950,416**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,560	616,940	17,160,860	3,071,490	12,376,990	39,660	700,420	14,119,070	23,248,870	37,367,940
ME	2,011,630	3,021,830	0	628,180	12,393,640	1,210	194,150	12,579,020	5,661,640	18,240,660
MA	1,782,070	955,140	5,597,860	9,727,720	21,819,520	37,190	595,320	22,452,230	18,062,790	40,515,020
NH	697,550	2,026,960	10,800,870	3,338,570	7,914,260	3,550	65,650	7,983,460	16,063,950	24,047,410
RI	95,340	0	0	0	6,440,270	0	0	6,440,270	95,340	6,535,610
VT	494,600	440,060	5,074,090	0	14,800	4,170	0	18,970	6,008,750	6,027,720
Total	**7,460,750**	**7,060,930**	**37,853,708**	**16,765,960**	**61,951,480**	**85,800**	**1,555,748**	**63,593,020**	**69,141,340**	**132,734,360**

Summary of Results: 2018 Strict Climate Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.8	88.8	56%	6,782	33,205,201	35,556,983	-2,351,784	7,908	8,251	-343	2.2	11.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	314	37	1,061	281	291	96	-284	-9	303	2,890

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,048	204	-3	-76	24	3	93	3,776	11.37	172	291	463	1.39	4,240	12.77

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,496	413	1,909	5.75	172	291	463	1.39	2,372	7.14

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.1%	3,162

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,289,844	17,307,397	83,360,391	32%	59,050,880	90,944,674	418,062,266

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,845,537	5,724	1,752	9,149,705	21,161	6,119
ME	6,327,378	3,998	1,707	6,330,643	4,435	1,816
MA	20,437,678	59,105	16,299	20,440,420	59,145	16,308
NH	7,410,492	22,496	6,200	7,419,297	22,498	6,203
RI	2,949,774	25	509	2,949,774	25	509
VT	509,263	1	1	517,230	2	3
Total	**48,480,122**	**91,348**	**28,468**	**46,807,069**	**107,265**	**30,958**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,300	617,010	2,996,310	35,556,650	33,205,201	20%	17%	3%	1,211,250	1,172,850	194,252,320
2,011,340	3,022,480	5,033,820	16,438,580	13,300,363						
1,781,860	938,780	2,720,640	40,186,330	64,675,456						
697,360	2,028,020	2,725,380	24,692,360	11,688,543						
95,280	0	95,280	7,046,230	12,333,051						
494,560	440,240	934,800	6,029,470	7,972,790						
7,459,700	**7,046,530**	**14,506,230**	**129,949,620**	**143,175,484**						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,300	617,010	17,160,880	3,099,390	11,514,650	36,900	728,520	12,280,070	23,276,580	35,556,650
ME	2,011,340	3,022,480	0	639,160	10,539,610	3,230	222,640	10,765,600	5,672,980	16,438,580
MA	1,781,860	938,780	5,547,860	9,953,960	21,196,710	39,650	678,410	21,914,770	18,271,560	40,186,330
NH	697,360	2,028,020	10,000,870	3,555,930	8,308,010	5,140	97,030	8,410,180	16,282,180	24,692,360
RI	95,280	0	0	0	6,950,950	0	0	6,950,950	95,280	7,046,230
VT	494,560	440,240	5,074,090	0	15,870	4,710	0	20,580	6,008,890	6,029,470
Total	7,459,700	7,046,530	37,853,700	17,247,540	58,525,800	89,730	1,726,620	60,342,150	69,607,470	129,949,620

Summary of Results: 2018 Strict Climate Scenario, Nuclear Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.0	86.6	56%	7,381	35,960,213	44,547,559	-8,567,308	8,606	9,451	-845	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
583	437	52	1,107	269	315	20	-707	-30	156	2,204

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,275	301	-9	-92	25	4	78	4,119	11.45	116	315	431	1.20	4,550	12.65

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,732	413	2,146	5.96	116	315	431	1.20	2,577	7.16

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.8%	3,541

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,534,007	16,815,278	78,922,508	24%	54,317,605	83,861,602	375,598,681

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,416,141	5,486	3,619	8,799,281	20,052	5,948
ME	6,139,212	3,779	1,627	6,141,685	4,215	1,736
MA	18,332,663	56,365	15,338	18,334,346	56,400	15,346
NH	6,947,141	20,568	5,696	6,954,630	20,569	5,698
RI	2,640,197	23	456	2,640,197	23	456
VT	508,503	0	1	515,798	2	2
Total	44,983,857	86,221	26,736	43,385,927	101,261	29,186

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,130	616,490	2,995,620	44,547,210	35,960,213	20%	17%	3%	1,211,090	1,172,830	214,928,360
2,011,300	3,022,240	5,033,540	16,023,030	13,300,363						
1,781,960	933,290	2,715,150	35,767,490	64,675,456						
697,260	2,026,910	2,724,170	24,049,160	11,688,543						
95,320	0	95,320	6,322,230	12,333,051						
494,490	439,760	934,270	6,027,380	2,972,790						
7,459,360	7,038,710	14,498,070	132,736,500	145,950,416						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,130	616,490	26,864,210	3,039,900	10,913,500	36,150	697,830	11,647,480	32,899,730	44,547,210
ME	2,011,300	3,022,240	0	609,530	10,168,590	2,600	208,770	10,379,960	5,643,070	16,023,030
MA	1,781,860	933,290	5,597,860	9,576,530	17,302,500	31,760	543,490	17,877,950	17,889,540	35,767,490
NH	697,260	2,026,910	10,000,870	3,255,140	7,992,010	4,030	82,940	8,068,980	15,980,180	24,049,160
RI	95,320	0	0	0	6,226,910	0	0	6,226,910	95,320	6,322,230
VT	494,490	439,760	5,074,090	0	15,130	3,890	0	19,020	6,008,360	6,027,380
Total	7,459,360	7,038,710	47,537,030	16,481,100	52,608,640	78,430	1,533,230	54,220,300	78,516,200	132,736,500

Summary of Results: 2018 Strict Climate Scenario, Coal Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
91.0	86.6	56%	7,381	35,980,713	44,547,559	-8,567,308	8,606	9,451	-845	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
302	371	88	1,284	548	315	20	-707	-30	156	2,348

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,275	301	-9	-92	25	4	78	4,119	11.45	116	315	431	1.20	4,550	12.65

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,977	413	2,390	6.36	116	315	431	1.20	2,721	7.56

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.8%	3,541

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
11,534,607	16,815,278	78,922,508	25%	54,317,605	83,861,602	375,588,681

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	14,549,753	5,486	5,619	16,932,893	20,652	5,948
ME	6,139,212	3,779	1,627	6,141,685	4,215	1,736
MA	14,332,663	56,365	15,338	14,334,346	56,400	15,346
NH	6,947,141	20,568	5,696	6,954,630	20,569	5,698
RI	2,640,197	23	456	2,640,197	23	456
VT	504,503	0	1	515,788	2	2
Total	53,117,469	86,221	28,736	51,519,539	101,861	29,186

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,130	616,490	2,995,620	44,547,210	35,900,213	20%	17%	3%	1,211,090	1,172,830	214,928,360
2,011,300	3,022,240	5,033,540	16,023,030	13,300,363						
1,781,860	933,290	2,715,150	35,767,490	64,675,456						
697,260	2,026,910	2,724,170	24,049,160	11,688,543						
95,320	0	95,320	6,322,230	12,333,051						
494,490	439,780	934,270	6,027,380	7,972,790						
7,459,360	7,038,710	14,498,070	132,736,500	145,950,416						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,130	616,490	17,180,880	12,335,897	10,913,500	36,150	697,830	11,647,480	32,512,397	44,159,877
ME	2,011,300	3,022,240	0	609,330	10,168,590	2,600	208,770	10,379,960	5,643,070	16,023,030
MA	1,781,860	933,290	5,597,860	9,376,530	17,302,500	31,760	543,690	17,877,950	17,889,540	35,767,490
NH	697,260	2,026,910	10,000,870	3,255,140	7,982,010	4,030	82,980	8,068,980	15,980,180	24,049,160
RI	95,320	0	0	0	6,226,910	0	0	6,226,910	95,320	6,322,230
VT	494,490	439,780	5,074,090	0	15,130	3,490	0	19,020	6,008,360	6,027,380
Total	7,459,360	7,038,710	37,853,700	25,777,097	52,608,640	78,430	1,533,230	54,220,300	78,128,867	132,349,167

Summary of Results: 2030 Strict Climate Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/kWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
107.6	102.5	55%	8,355	40,456,272	49,921,027	-9,464,716	9,742	10,647	-904	3.0	11.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	384	72	2,080	776	310	24	-929	-33	156	3,863

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustments for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,354	355	-42	-86	18	11	77	5,399	13.32	116	310	426	1.05	5,817	14.38

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,596	413	3,010	7.44	116	310	426	1.05	3,436	8.49

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	3,619

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
29,039,940	37,535,078	188,370,637	53%	91,366,526	140,279,589	633,336,798

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,224,977	3,793	4,057	14,543,713	17,094	6,140
ME	9,277,064	2,276	1,824	9,281,930	2,724	1,937
MA	19,438,326	39,767	11,641	19,449,803	38,928	11,643
NH	4,676,335	9,155	2,788	4,692,311	9,160	2,793
RI	3,174,572	27	548	3,174,572	27	548
VT	1,437,820	12	148	1,448,291	14	151
Total	54,229,155	54,821	21,013	52,590,620	67,847	23,232

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,640	621,750	3,145,390	49,920,720	40,456,272	25%	20%	3%	1,254,600	1,273,850	228,003,953
2,105,920	3,028,160	5,134,080	24,129,570	15,506,927						
1,761,150	1,107,410	2,868,560	43,113,000	73,831,318						
674,630	2,059,030	2,733,660	21,338,730	14,450,182						
90,720	0	90,720	7,655,380	14,013,464						
571,520	445,800	1,017,320	8,131,560	9,246,022						
7,727,580	7,262,150	14,989,730	154,288,960	167,504,187						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,523,640	621,750	17,160,600	2,680,490	26,531,930	45,440	336,870	26,914,240	23,006,480	49,920,720
ME	2,105,920	3,028,160	0	443,600	18,444,280	4,980	62,630	18,551,890	5,577,680	24,129,570
MA	1,761,150	1,107,410	5,597,860	6,649,540	27,562,850	26,810	407,380	27,997,040	15,115,960	43,113,000
NH	674,630	2,059,030	9,912,800	1,463,800	7,203,200	11,460	13,650	7,228,390	14,110,340	21,338,730
RI	90,720	0	0	0	7,564,660	0	0	7,564,660	90,720	7,655,380
VT	571,520	445,800	5,014,570	0	2,084,580	15,090	0	2,099,670	6,031,890	8,131,560
Total	7,727,580	7,262,150	37,705,910	11,237,430	89,431,580	103,780	820,530	90,355,890	63,933,070	154,288,960

Summary of Results: 2030 Strict Climate Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
106.8	102.6	56%	7,678	37,335,975	49,950,636	-12,614,619	8,953	10,647	-1,694	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
220	384	72	2,078	782	286	6	-1,249	-59	232	2,754

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,997	310	-17	-80	19	10	78	4,953	13.27	172	286	459	1.23	5,411	14.49

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION $VC COST	AVERAGE GENERATION $VC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,236	413	2,649	7.10	172	286	459	1.23	3,108	8.32

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.3%	4,548

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,771,262	37,500,311	187,820,924	53%	87,210,517	134,438,950	609,865,312

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,249,424	3,858	4,122	14,618,886	17,716	6,290
ME	9,347,225	2,375	1,858	9,351,654	2,823	1,971
MA	19,490,067	38,781	11,656	19,495,088	38,851	11,674
NH	4,810,271	9,521	2,892	4,827,064	9,526	2,897
RI	2,528,902	22	437	2,528,902	22	437
VT	600,416	4	3	611,284	7	6
Total	**53,056,306**	**54,562**	**20,969**	**51,432,879**	**68,944**	**23,274**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,650	621,790	3,145,440	49,950,340	37,335,975	23%	20%	3%	1,254,600	1,273,660	207,191,432
2,105,950	3,029,640	5,135,590	24,281,200	15,506,927						
1,761,170	1,101,720	2,862,890	43,236,990	73,831,318						
674,640	2,059,260	2,733,900	21,574,050	14,450,182						
90,730	0	90,730	6,052,570	14,013,464						
571,520	446,020	1,017,540	6,066,105	9,246,022						
7,727,660	**7,258,430**	**14,986,090**	**151,161,255**	**164,383,889**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,523,650	621,790	17,180,600	2,764,320	26,445,370	39,510	375,100	26,859,980	23,090,360	49,950,340
ME	2,105,950	3,029,640	0	463,590	18,616,750	4,510	60,960	18,682,220	5,598,980	24,281,200
MA	1,761,170	1,101,720	5,507,840	6,610,390	27,677,870	28,850	459,190	28,165,850	15,071,140	43,236,990
NH	674,640	2,059,260	9,912,600	1,522,510	7,300,520	11,890	12,150	7,404,760	14,169,290	21,574,050
RI	90,730	0	0	0	5,961,840	0	0	5,961,840	90,730	6,052,570
VT	571,520	446,020	5,014,570	0	18,630	15,365	0	33,995	6,032,110	6,066,105
Total	**7,727,660**	**7,258,430**	**37,705,910**	**11,360,810**	**86,180,980**	**100,075**	**907,590**	**87,108,645**	**64,052,610**	**151,161,255**

Summary of Results: 2030 Strict Climate Scenario, Nuclear Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
104.6	99.1	55%	8,355	40,456,272	55,244,024	-14,787,709	9,742	11,547	-1,804	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
776	499	79	1,885	673	310	1	-1,395	-90	156	2,894

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,232	485	-36	-103	17	14	69	5,382	13.30	116	310	426	1.05	5,807	14.35

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,428	413	2,841	7.02	116	310	426	1.05	3,267	8.08

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	4,518

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)	(MMBtu)	(MMBtu)
24,690,155	32,391,888	158,815,797	40%	80,809,436	127,657,456	568,959,415

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	14,208,982	3,462	3,626	12,665,021	16,203	5,625
ME	8,417,982	2,486	1,723	8,421,524	2,933	1,835
MA	18,095,563	37,084	11,046	18,109,603	37,150	11,063
NH	4,715,972	9,448	2,859	4,733,649	9,453	2,864
RI	2,422,130	21	418	2,422,130	21	418
VT	2,162,320	23	274	2,173,750	25	277
Total	50,022,949	52,523	19,947	48,524,677	65,785	22,082

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,130	619,220	3,126,350	55,243,770	46,456,272	23%	20%	3%	1,244,400	1,267,530	229,344,125
2,105,350	3,026,020	5,131,370	21,942,880	15,506,927						
1,760,690	908,230	2,668,920	40,045,690	73,931,318						
674,410	2,066,000	2,740,410	21,365,470	14,450,182						
90,660	0	90,660	5,798,080	14,013,464						
571,310	445,060	1,016,370	9,898,044	9,246,022						
7,709,550	7,064,530	14,774,080	154,293,934	167,504,187						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,507,130	619,220	26,863,930	2,569,310	22,357,360	38,370	288,450	22,684,180	32,559,590	55,243,770
ME	2,105,350	3,026,020	0	454,550	16,253,950	3,610	99,400	16,356,960	5,585,920	21,942,880
MA	1,760,690	908,230	5,597,860	6,338,030	24,983,920	26,540	430,420	25,440,880	14,604,810	40,045,690
NH	674,410	2,066,000	9,912,800	1,500,610	7,122,050	12,690	26,830	7,211,570	14,153,900	21,365,470
RI	90,660	0	0	0	5,707,420	0	0	5,707,420	90,660	5,798,080
VT	571,310	445,060	5,014,570	0	3,839,970	27,134	0	3,867,104	6,030,940	9,898,044
Total	7,709,550	7,064,530	47,389,240	10,862,500	80,314,670	108,344	845,100	81,268,114	73,025,820	154,293,934

Summary of Results: 2030 Strict Climate Scenario, Coal Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
104.6	99.1	55%	8,355	40,456,272	55,244,024	-14,787,709	9,742	11,547	-1,804	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
494	432	115	2,067	1,160	310	1	-1,395	-90	156	3,252

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,232	495	-36	-103	17	14	69	5,380	13.30	116	310	426	1.05	5,807	14.35

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,795	413	3,198	7.91	116	310	426	1.05	3,625	8.96

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.6%	4,518

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
24,690,155	32,391,822	158,815,797	41%	80,809,436	127,657,456	568,959,415

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	22,342,594	3,462	3,626	20,799,633	16,203	5,625
ME	8,417,982	2,486	1,723	8,421,524	2,933	1,835
MA	18,093,563	37,084	11,046	18,109,603	37,150	11,063
NH	4,735,972	9,448	2,859	4,733,649	9,453	2,864
RI	2,422,130	21	418	2,422,130	21	418
VT	2,162,320	23	274	2,173,750	25	277
Total	**58,156,561**	**52,523**	**19,947**	**56,658,289**	**65,785**	**22,082**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,507,130	619,220	3,126,350	55,243,770	40,456,272	23%	20%	3%	1,244,400	1,267,530	226,344,125
2,105,350	3,026,020	5,131,370	21,942,880	15,506,927						
1,760,690	908,230	2,668,920	40,045,690	73,831,318						
674,410	2,066,000	2,740,410	21,165,470	14,450,182						
90,660	0	90,660	5,796,080	14,013,464						
571,310	445,060	1,016,370	9,498,644	9,246,022						
7,709,550	**7,064,530**	**14,774,080**	**154,293,934**	**167,504,187**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,507,130	619,220	17,180,600	11,865,307	22,357,360	38,370	288,450	22,684,180	32,172,257	54,856,437
ME	2,105,350	3,026,020	0	454,550	16,253,950	3,610	99,400	16,356,960	5,585,920	21,942,880
MA	1,760,690	908,230	5,597,860	6,338,030	24,983,920	26,540	430,420	25,440,880	14,604,810	40,045,690
NH	674,410	2,066,000	9,912,000	1,500,610	7,172,050	12,690	26,830	7,211,570	14,153,900	21,365,470
RI	90,660	0	0	0	5,707,420	0	0	5,707,420	90,660	5,798,080
VT	571,310	445,060	5,014,570	0	3,839,970	27,134	0	3,867,104	6,030,940	9,898,044
Total	**7,709,550**	**7,064,530**	**37,705,910**	**20,158,497**	**80,314,670**	**108,344**	**845,100**	**81,268,114**	**72,638,487**	**153,906,601**

Summary of Results: 2013 High Fuel/Growth Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
106.5	102.0	55%	7,431	35,821,252	37,511,483	-1,690,200	8,664	8,251	413	4.4	9.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	44	1,507	83	229	174	-294	22	103	2,182

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,815	460	-20	-90	29	8	67	4,909	13.70	121	229	350	0.98	5,259	14.68

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,950	413	2,264	6.32	121	229	350	0.98	2,613	7.30

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	2,056

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO-NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
9,979,610	15,634,105	73,837,959	27%	41,723,223	82,578,459	339,566,981

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	11,372,578	15,012	6,874	11,583,834	35,904	9,710
ME	6,842,707	5,680	2,146	6,842,328	6,118	2,256
MA	22,677,599	84,202	22,155	22,673,003	84,243	22,162
NH	7,416,343	26,654	7,117	7,416,884	26,654	7,117
RI	2,028,734	18	350	2,029,552	19	351
VT	550,417	0	1	553,142	1	1
Total	50,888,398	131,566	38,644	51,098,742	152,938	41,597

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,120	617,930	3,003,050	37,511,190	35,421,252	13%	10%	3%	1,131,930	1,257,990	120,277,724
2,093,860	3,020,750	5,114,610	17,173,680	12,743,007						
1,761,600	771,820	2,533,420	39,267,870	62,491,915						
708,950	2,027,730	2,736,680	23,615,754	10,958,032						
94,260	0	94,260	4,696,970	11,946,395						
539,210	440,670	979,880	5,959,840	7,669,557						
7,583,000	6,878,900	14,461,900	128,427,384	141,630,157						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,385,120	617,930	17,091,580	3,851,890	10,277,110	36,540	3,251,020	13,564,670	23,946,520	37,511,190
ME	2,093,860	3,020,750	0	462,000	10,802,960	20	594,090	11,397,070	5,776,610	17,173,680
MA	1,761,600	771,820	5,597,860	12,360,590	15,422,170	21,880	3,331,950	18,776,000	20,491,870	39,267,870
NH	708,950	2,027,730	10,000,870	4,102,360	6,527,280	354	248,210	6,775,844	16,839,910	23,615,754
RI	94,260	0	0	0	4,800,010	4,700	0	4,804,710	94,260	4,898,970
VT	539,210	440,670	4,969,930	0	8,710	1,320	0	10,030	5,949,910	5,959,940
Total	7,583,000	6,878,900	37,660,240	20,976,840	47,838,240	64,814	7,425,270	55,328,324	73,098,980	128,427,384

Summary of Results: 2013 High Fuel/Growth Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
105.7	101.6	57%	7,109	35,272,768	37,695,252	-2,422,472	8,289	8,251	38	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
0	315	45	1,520	84	225	132	-339	2	155	2,138

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,727	443	-14	-88	30	8	67	4,799	13.61	300	225	525	1.49	5,324	15.09

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,758	413	2,172	6.16	300	225	525	1.49	2,696	7.64

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	2,485

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
10,142,706	15,581,280	74,462,632	28%	40,735,570	80,676,941	333,539,457

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	11,483,712	15,150	6,965	11,693,639	36,280	9,809
ME	6,225,885	6,034	2,117	6,226,896	6,473	2,226
MA	22,864,620	84,385	22,226	22,858,490	84,425	22,233
NH	7,559,055	26,819	7,183	7,599,992	26,819	7,183
RI	2,035,868	18	352	2,035,868	18	352
VT	550,653	0	1	553,103	1	1
Total	50,759,795	132,406	38,843	50,967,777	154,014	41,804

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,385,120	617,360	3,002,480	37,694,920	35,272,768	13%	10%	3%	1,131,940	1,257,960	117,584,781
2,093,920	3,021,520	5,115,440	15,547,490	12,743,007						
1,761,580	823,120	2,584,700	39,740,350	62,491,915						
708,960	2,029,710	2,738,670	24,019,320	10,938,032						
94,260	0	94,260	4,917,800	11,946,395						
539,220	440,700	979,920	5,960,010	7,669,557						
7,582,860	6,932,410	14,515,470	127,879,890	141,081,674						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,385,120	617,360	17,091,580	3,850,020	10,372,540	37,720	3,350,580	13,750,840	23,944,080	37,694,920
ME	2,093,920	3,021,520	0	662,590	9,091,410	840	677,210	9,769,460	5,778,030	15,547,490
MA	1,761,580	823,120	5,597,860	12,362,530	15,792,690	17,930	3,384,640	19,195,260	20,545,090	39,740,350
NH	708,960	2,029,710	10,000,870	4,104,180	6,891,600	590	283,610	7,175,600	16,843,720	24,019,320
RI	94,260	0	0	0	4,823,540	0	0	4,823,540	94,260	4,917,800
VT	539,220	440,700	4,969,930	0	8,930	1,230	0	10,160	5,949,850	5,960,010
Total	7,583,860	6,932,410	37,660,240	20,979,320	46,980,710	48,110	7,696,040	54,724,860	73,155,030	127,879,890

Summary of Results: 2018 High Fuel/Growth Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
113.4	108.8	54%	7,919	37,205,520	45,891,359	-8,685,501	9,234	10,047	-813	4.8	9.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
180	372	66	2,263	284	326	17	-925	-47	156	2,693

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,219	537	-32	-90	26	11	64	5,445	14.64	116	326	442	1.19	5,887	15.82

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,210	413	2,624	7.05	116	326	442	1.19	3,066	8.24

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,420

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
18,655,831	28,214,814	137,410,783	42%	52,598,591	94,361,898	464,102,074

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,020,410	14,695	7,087	14,635,225	33,704	9,787
ME	7,154,811	4,554	1,968	7,154,953	4,980	2,077
MA	21,676,714	76,715	20,809	21,669,288	78,747	20,814
NH	7,556,752	28,662	7,631	7,558,329	28,862	7,631
RI	1,539,650	13	266	1,539,993	14	266
VT	506,369	0	1	509,213	0	1
Total	54,454,506	126,848	37,761	53,067,801	146,317	40,576

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,150	617,460	2,996,610	45,891,060	37,205,520	20%	17%	3%	1,211,110	1,172,840	224,053,295
2,011,060	3,021,660	5,032,720	18,325,780	13,537,869						
1,781,730	1,000,140	2,781,870	38,564,790	65,830,201						
697,120	2,030,160	2,727,280	23,385,370	11,897,250						
95,240	0	95,240	3,736,950	12,553,624						
494,470	440,870	935,340	6,019,820	8,115,192						
7,458,770	7,110,290	14,569,060	135,923,790	149,139,734						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,379,150	617,460	17,160,880	4,208,130	19,363,520	29,880	2,112,060	21,505,460	24,385,620	45,891,080
ME	2,011,060	3,021,660	0	669,370	12,306,660	350	316,280	12,623,290	5,702,490	18,325,780
MA	1,781,730	1,000,140	5,597,860	12,344,080	15,883,750	12,040	1,944,590	17,840,380	20,724,410	38,564,790
NH	697,120	2,030,160	10,000,870	4,536,640	5,886,420	550	129,610	6,116,580	17,268,790	23,385,370
RI	95,240	0	0	0	3,039,700	2,010	0	3,641,710	95,240	3,736,950
VT	494,470	440,870	5,074,090	0	9,270	1,120	0	10,390	6,009,430	6,019,820
Total	7,458,770	7,110,290	37,853,700	21,761,220	57,191,320	45,950	4,502,540	61,739,810	74,183,980	135,923,790

Summary of Results: 2018 High Fuel/Growth Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
113.6	109.9	55%	7,102	35,484,718	42,410,070	-6,925,317	8,514	9,148	-634	4.1	9.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
93	344	56	1,948	259	311	29	-766	-31	303	2,547

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,031	421	-15	-49	29	10	69	5,124	14.44	172	311	483	1.36	5,607	15.80

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,933	413	2,346	6.61	172	311	483	1.36	2,829	7.97

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	3,342

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
14,972,778	23,251,045	111,953,839	37%	49,052,594	90,964,740	389,678,702

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	14,697,553	14,909	6,943	13,280,423	34,274	9,676
ME	7,265,030	4,684	2,015	7,265,330	5,120	2,123
MA	22,336,752	79,187	20,969	22,130,235	79,221	20,995
NH	7,664,364	29,013	7,682	7,666,047	29,014	7,683
RI	1,647,146	14	284	1,647,146	14	284
VT	506,679	0	1	509,845	0	1
Total	**53,917,524**	**127,807**	**37,914**	**52,499,823**	**147,643**	**40,764**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,440	618,180	2,997,620	42,409,730	35,464,718	20%	12%	5%	1,211,310	1,172,930	211,228,136
2,011,500	3,021,560	5,033,060	18,559,660	13,537,869						
1,781,970	1,060,870	2,842,840	39,606,466	65,830,301						
697,470	2,030,420	2,727,890	23,608,880	11,897,230						
95,340	0	95,340	3,994,670	12,553,624						
494,560	441,190	935,750	6,021,120	8,115,192						
7,460,280	**7,172,220**	**14,632,500**	**134,200,526**	**147,418,932**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NUT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,440	618,180	17,180,880	4,216,040	15,742,170	25,960	2,247,060	18,015,190	24,394,540	42,409,730
ME	2,011,500	3,021,560	0	670,890	12,510,770	300	344,640	12,855,710	5,703,950	18,559,660
MA	1,781,970	1,060,870	5,597,860	12,376,380	16,764,640	11,036	2,013,490	18,789,166	20,817,080	39,606,466
NH	697,470	2,030,420	10,000,870	4,551,260	6,182,010	550	145,800	6,328,360	17,280,520	23,608,880
RI	95,340	0	0	0	3,899,330	0	0	3,899,330	95,340	3,994,670
VT	494,560	441,190	5,074,090	0	10,020	1,260	0	11,280	6,009,840	6,021,120
Total	**7,460,280**	**7,172,220**	**37,853,700**	**21,815,070**	**55,108,960**	**39,106**	**4,751,190**	**59,899,256**	**74,301,270**	**134,200,526**

Summary of Results: 2018 High Fuel/Growth Scenario, Nuclear Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
111.3	105.6	54%	7,919	37,205,520	49,824,307	-12,618,744	9,234	10,348	-1,114	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
735	480	69	1,844	237	326	3	-1,267	-71	156	2,511

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,142	592	-27	-108	40	12	61	5,419	14.57	116	326	442	1.19	5,861	15.75

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,029	413	2,442	6.56	116	326	442	1.19	2,884	7.75

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,720

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)	(MMBtu)	(MMBtu)
12,968,116	21,684,028	99,076,552	26%	45,243,499	83,214,736	342,025,721

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	13,364,484	14,065	6,444	12,124,618	32,257	9,046
ME	6,881,548	4,438	1,897	6,882,042	4,872	2,005
MA	20,720,090	77,420	20,362	20,718,166	77,464	20,371
NH	7,266,597	28,281	7,455	7,268,263	28,281	7,455
RI	1,309,279	11	226	1,309,279	11	226
VT	505,283	0	0	508,021	0	1
Total	50,047,181	124,215	36,384	48,811,419	142,886	39,105

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,371,030	616,900	2,987,930	49,823,990	37,205,520	20%	17%	3%	1,205,660	1,170,370	224,301,440
2,008,240	3,022,430	5,030,670	17,680,670	13,537,869						
1,779,680	769,230	2,548,910	36,380,390	65,830,301						
695,630	2,029,750	2,725,380	22,828,420	11,897,230						
95,050	0	95,050	3,192,120	12,553,624						
493,760	440,420	934,180	6,018,060	8,115,192						
7,443,390	6,878,730	14,322,120	135,923,650	149,139,734						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,371,030	616,900	26,864,210	4,132,920	13,954,020	25,350	1,659,560	15,838,930	33,965,060	49,623,990
ME	2,008,240	3,022,430	0	664,170	11,688,960	510	296,340	11,985,430	5,694,840	17,680,670
MA	1,779,680	769,230	5,597,860	12,200,380	14,189,940	16,160	1,827,140	16,033,240	20,347,150	36,380,390
NH	695,630	2,029,750	10,000,870	4,479,440	5,541,500	430	60,800	5,622,730	17,205,690	22,828,420
RI	95,050	0	0	0	3,097,070	0	0	3,097,070	95,050	3,192,120
VT	493,760	440,420	5,074,090	0	8,940	850	0	9,790	6,008,270	6,018,060
Total	7,443,390	6,878,730	47,537,030	21,476,910	48,480,450	43,300	4,043,840	52,587,590	83,336,060	135,923,650

Summary of Results: 2018 High Fuel/Growth Scenario, Coal Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
111.3	105.6	54%	7,919	37,205,520	49,824,307	-12,618,744	9,234	10,348	-1,114	5.3	8.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
425	406	109	2,029	402	326	3	-1,267	-71	156	2,518

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,142	592	-27	-108	40	12	61	5,419	14.57	116	326	442	1.19	5,861	15.75

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,036	413	2,449	6.58	116	326	442	1.19	2,891	7.77

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	3,720

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,968,116	21,684,028	99,076,552	28%	45,243,499	83,314,736	342,025,723

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	21,499,096	14,065	6,444	20,256,261	32,257	9,046
ME	6,881,548	4,438	1,897	6,882,042	4,872	2,005
MA	20,720,890	77,420	20,362	20,719,166	77,464	20,371
NH	7,266,597	28,281	7,455	7,268,263	28,281	7,455
RI	1,309,279	11	226	1,309,279	11	226
VT	505,383	0	0	508,021	0	1
Total	**58,180,993**	**124,215**	**36,384**	**56,945,831**	**142,886**	**39,105**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,371,030	616,900	2,987,930	49,824,890	37,205,520	20%	17%	3%	1,205,460	1,170,370	224,301,440
2,008,240	3,022,430	5,030,670	17,680,670	13,537,869						
1,779,680	769,230	2,548,910	36,630,390	65,830,301						
695,630	2,029,750	2,725,380	22,828,420	11,897,230						
95,050	0	95,050	3,192,120	12,553,624						
493,760	440,420	934,180	6,018,060	8,115,192						
7,443,390	**6,878,730**	**14,322,120**	**135,923,650**	**149,139,734**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,371,030	616,900	17,180,850	13,428,917	13,954,020	25,350	1,859,360	15,838,930	33,597,727	49,436,657
ME	2,008,240	3,022,430	0	664,170	11,648,940	510	296,340	11,985,830	5,694,840	17,680,670
MA	1,779,680	769,230	5,597,860	12,200,390	14,189,940	16,160	1,827,140	16,033,240	20,347,150	36,380,390
NH	695,630	2,029,750	10,000,070	4,479,440	5,541,500	430	80,800	5,622,730	17,205,690	22,828,420
RI	95,050	0	0	0	3,097,070	0	0	3,097,070	95,050	3,192,120
VT	493,760	440,420	5,074,090	0	8,940	850	0	9,790	6,008,270	6,018,060
Total	**7,443,390**	**6,878,730**	**37,853,708**	**30,772,907**	**48,480,450**	**43,300**	**4,063,840**	**52,587,590**	**82,948,727**	**135,536,317**

Summary of Results: 2030 High Fuel/Growth Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.06 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
122.8	116.9	53%	8,965	41,834,315	53,813,695	-11,979,339	10,453	11,847	-1,393	8.1	5.4	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
362	430	87	3,210	567	321	16	-1,359	-135	156	3,655

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,138	1,015	-68	-99	10	41	41	6,991	16.71	116	321	437	1.04	7,428	17.76

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,178	413	3,592	8.59	116	321	437	1.04	4,029	9.63

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,006

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
28,618,826	40,602,345	198,709,323	52%	82,688,826	133,957,011	565,955,018

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,733,748	12,758	6,860	17,382,292	29,476	9,336
ME	8,375,958	3,894	2,026	8,377,215	4,340	2,138
MA	24,126,091	76,647	20,788	24,130,354	76,724	20,805
NH	7,023,043	28,639	7,494	7,030,408	28,642	7,497
RI	1,919,581	17	335	1,939,581	17	335
VT	2,304,532	30	300	2,309,481	32	302
Total	62,502,953	121,985	37,803	61,169,331	139,231	40,413

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,522,220	619,960	3,142,180	53,813,370	41,834,315	23%	20%	3%	1,253,770	1,273,250	237,223,238
2,104,860	3,026,900	5,131,760	21,497,898	15,781,869						
1,760,340	1,433,340	3,193,680	45,599,640	75,149,717						
674,250	2,077,130	2,751,380	22,095,950	14,708,453						
90,640	0	90,640	4,709,120	14,263,939						
571,190	447,010	1,018,190	10,216,448	9,411,148						
7,723,490	7,604,340	15,327,830	157,932,226	171,151,340						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,522,220	619,960	17,180,600	4,099,100	28,165,970	36,350	1,189,170	29,391,490	24,421,880	53,813,370
ME	2,104,860	3,026,900	0	698,520	15,542,920	1,278	122,420	15,666,618	5,831,280	21,497,898
MA	1,760,340	1,433,340	5,597,860	12,298,330	23,010,590	14,230	1,494,750	24,519,570	21,079,870	45,599,440
NH	674,250	2,077,130	9,912,000	4,590,420	4,820,660	9,070	11,546	4,841,270	17,254,680	22,095,950
RI	90,640	0	0	0	4,618,480	0	0	4,618,480	90,640	4,709,120
VT	571,190	447,010	5,014,570	0	4,143,638	40,050	0	4,183,688	6,032,760	10,216,448
Total	7,723,490	7,604,340	37,705,918	21,677,370	80,302,258	100,978	2,817,886	83,221,116	74,711,110	157,932,226

Summary of Results: 2030 High Fuel/Growth Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss - grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
123.6	119.1	55%	8,266	39,900,137	52,926,397	-13,026,217	9,639	11,547	-1,908	7.0	7.0	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
331	420	85	3,120	559	306	5	-1,524	-160	232	3,375

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
4,931	806	-38	-95	15	30	49	6,553	16.42	172	306	478	1.20	7,032	17.62

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
2,937	413	3,250	8.15	172	306	478	1.20		3,728	9.34

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.5%	4,636

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation		ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)		(MMBtu)		(MMBtu)
27,603,748	39,040,636	191,350,032	51%		79,457,026	129,775,774	550,049,734

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,545,988	13,112	6,930	17,115,065	30,106	9,470
ME	8,487,332	3,898	2,046	8,488,784	4,344	2,158
MA	23,346,660	77,531	20,934	23,851,056	77,615	20,953
NH	7,223,224	28,964	7,600	7,230,283	28,968	7,603
RI	1,953,448	17	337	1,953,448	17	337
VT	1,965,820	22	241	1,970,797	23	242
Total	**62,022,472**	**123,544**	**38,088**	**60,609,434**	**141,273**	**40,762**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,523,540	619,990	3,143,530	52,926,140	39,900,137	23%	20%	3%	1,254,540	1,273,000	224,296,506
2,105,850	3,026,880	5,132,730	21,776,214	15,783,869						
1,761,110	1,389,710	3,150,820	44,649,230	75,149,717						
674,620	2,074,530	2,749,150	22,502,350	14,708,453						
90,730	0	90,730	4,748,890	14,263,839						
571,490	446,750	1,018,240	9,404,160	9,411,148						
7,727,340	**7,557,860**	**15,285,200**	**156,006,984**	**169,217,163**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,523,540	619,990	17,180,600	4,137,790	27,091,570	25,300	1,347,350	28,464,220	24,461,920	52,926,140
ME	2,105,850	3,026,880	0	703,710	15,820,810	1,504	117,460	15,939,774	5,836,440	21,776,214
MA	1,761,110	1,389,710	5,597,860	12,408,360	21,950,990	14,400	1,546,800	23,492,190	21,157,040	44,649,230
NH	674,620	2,074,530	9,912,800	4,640,920	5,177,130	8,380	13,890	5,199,400	17,302,950	22,502,350
RI	90,730	0	0	0	4,658,160	0	0	4,658,160	90,730	4,748,890
VT	571,490	446,750	5,014,570	0	3,344,380	26,970	0	3,371,350	6,032,810	9,404,160
Total	7,727,340	7,557,860	37,705,910	21,890,780	78,023,040	76,554	3,025,500	81,125,094	74,881,890	156,006,984

Summary of Results: 2030 High Fuel/Growth Scenario, Nuclear Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
120.3	113.4	53%	8,965	41,834,315	58,193,095	-16,358,737	10,453	12,747	-2,293	7.9	6.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
973	556	92	2,793	494	321	0	-1,779	-217	156	3,389

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,032	989	-71	-118	14	48	43	6,827	16.32	116	321	437	1.04	7,264	17.36

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,912	413	3,325	7.95	116	321	437	1.04	3,762	8.99

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
23,651,765	35,824,972	163,037,074	40%	72,012,124	122,443,978	503,117,617

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,257,109	12,393	6,346	15,138,851	29,553	8,754
ME	8,433,192	3,939	2,046	8,434,904	4,385	2,157
MA	23,454,725	76,500	20,640	23,459,392	76,586	20,659
NH	7,129,545	28,535	7,490	7,136,162	28,538	7,492
RI	1,863,736	16	322	1,863,736	16	322
VT	1,256,092	11	117	1,260,479	12	118
Total	58,394,399	121,394	36,961	57,293,525	138,091	39,582

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,483,790	617,320	3,101,110	58,192,810	41,834,315	23%	20%	3%	1,231,300	1,257,260	237,972,617
2,104,780	3,024,340	5,129,120	21,619,081	15,783,869						
1,760,310	983,250	2,743,560	43,551,150	75,149,717						
674,240	2,068,610	2,742,850	22,378,290	14,708,453						
90,640	0	90,640	4,534,310	14,263,839						
571,170	446,060	1,017,230	7,673,570	9,411,148						
7,684,930	7,139,580	14,824,510	157,949,411	171,151,340						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,483,790	617,320	26,863,930	4,010,950	23,066,650	36,900	1,093,270	24,216,820	33,975,990	58,192,810
ME	2,104,780	3,024,340	0	699,790	15,655,580	1,761	132,830	15,790,171	5,828,910	21,619,081
MA	1,760,310	983,250	5,597,860	12,253,240	21,426,550	12,120	1,517,820	22,956,490	20,594,660	43,551,150
NH	674,240	2,068,610	9,912,860	4,574,560	5,130,280	7,400	10,320	5,148,000	17,230,290	22,378,290
RI	90,640	0	0	0	4,443,870	0	0	4,443,870	90,640	4,534,510
VT	571,170	446,060	5,014,570	0	1,620,480	15,290	0	1,641,770	6,031,800	7,673,570
Total	7,684,930	7,139,580	47,389,240	21,538,540	71,369,410	73,471	2,754,240	74,197,121	83,752,290	157,949,411

Summary of Results: 2030 High Fuel/Growth Scenario, Coal Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
120.3	113.4	53%	8,965	41,834,315	58,193,095	-16,358,737	10,453	12,747	-2,293	7.9	6.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
663	483	132	2,981	783	321	0	-1,779	-217	156	3,523

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
5,032	969	-71	-118	14	48	43	6,927	16.32	116	321	437	1.04	7,364	17.36

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
3,046	413	3,460	8.27	116	321	437	1.04	3,897	9.31

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
23,651,765	35,824,972	163,037,074	40%	72,012,124	122,443,978	503,117,617

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	24,290,723	12,393	6,346	23,272,464	29,553	8,754
ME	8,433,192	3,939	2,046	8,434,904	4,385	2,157
MA	23,454,725	76,500	20,640	23,459,392	76,586	20,659
NH	7,129,545	28,535	7,490	7,136,162	28,538	7,492
RI	1,863,736	16	322	1,863,736	16	322
VT	1,256,092	11	117	1,260,479	12	118
Total	**66,528,011**	**121,394**	**36,961**	**65,427,137**	**138,091**	**39,502**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,483,790	617,320	3,101,110	58,192,816	41,834,315	23%	20%	3%	1,231,300	1,257,260	237,972,617
2,104,780	3,024,340	5,129,120	21,619,081	15,783,869						
1,760,310	983,250	2,743,560	43,551,150	75,149,717						
674,240	2,068,610	2,742,850	22,378,290	14,708,453						
90,640	0	90,640	4,534,510	14,263,839						
571,170	446,060	1,017,230	7,673,570	9,411,148						
7,684,930	**7,139,580**	**14,824,510**	**157,949,411**	**171,151,340**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,483,790	617,320	17,160,600	13,306,947	23,086,650	36,900	1,093,270	24,216,820	33,588,657	57,805,477
ME	2,104,780	3,024,340	0	690,790	15,655,580	1,761	132,830	15,790,171	5,829,910	21,619,081
MA	1,760,310	983,250	5,597,860	12,253,240	21,426,550	12,120	1,517,820	22,956,490	20,594,660	43,551,150
NH	674,240	2,068,610	9,912,900	4,574,560	5,130,240	7,400	10,120	5,148,900	17,229,390	22,378,290
RI	90,640	0	0	0	4,443,870	0	0	4,443,870	90,640	4,534,510
VT	571,170	446,060	5,014,570	0	1,626,480	15,290	0	1,641,770	6,031,800	7,673,570
Total	**7,684,930**	**7,139,580**	**37,705,910**	**30,834,537**	**71,369,410**	**73,471**	**2,754,240**	**74,197,121**	**83,364,957**	**157,562,078**

Summary of Results: 2013 Low Stress Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
51.2	49.4	59%	7,622	39,117,038	38,811,248	305,780	8,887	8,550	337	3.3	10.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
23	323	47	860	61	250	122	-87	13	103	1,714

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,004	351	-7	-45	14	3	75	2,755	7.04	121	250	371	0.95	3,126	7.99

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,361	413	1,774	4.54	121	250	371	0.95	2,145	5.48

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
17.7%	2,105

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
13,470,878	21,172,977	105,277,905	37%	64,027,428	115,311,245	549,412,844

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,448,665	5,316	4,062	10,630,666	21,124	6,127
ME	8,294,450	3,118	1,836	8,294,517	3,555	1,945
MA	19,822,994	36,324	11,135	19,789,095	36,404	11,144
NH	5,414,425	10,443	3,194	5,417,948	10,444	3,195
RI	4,233,012	37	731	4,265,649	80	746
VT	553,185	1	1	560,255	2	3
Total	48,766,732	55,239	20,958	48,957,119	71,610	23,359

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,385,280	615,600	3,000,880	38,810,900	39,117,038	13%	10%	3%	1,132,130	1,257,940	136,446,606
2,093,800	3,020,420	5,114,220	21,417,830	14,068,666						
1,761,640	974,340	2,735,980	43,700,080	66,992,625						
709,020	2,023,960	2,732,980	22,881,200	12,097,990						
94,150	0	94,150	9,955,560	13,189,124						
539,270	438,880	978,150	5,967,318	8,467,445						
7,583,160	7,073,200	14,656,360	142,732,888	155,932,889						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,385,280	615,600	17,091,580	2,469,590	14,494,920	43,480	1,710,450	16,248,850	22,562,050	38,810,900
ME	2,093,800	3,020,420	0	359,910	15,575,020	60	368,620	15,943,700	5,474,130	21,417,830
MA	1,761,640	974,340	5,597,860	5,242,470	28,315,670	35,660	1,772,440	30,123,770	13,576,310	43,700,080
NH	709,020	2,023,960	10,080,870	1,539,010	8,405,480	1,640	201,200	8,608,340	14,272,860	22,881,200
RI	94,150	0	0	0	9,668,160	193,250	0	9,861,410	94,150	9,955,560
VT	539,270	438,880	4,969,930	0	15,000	4,238	0	19,238	5,948,080	5,967,318
Total	7,583,160	7,073,200	37,660,240	9,610,980	76,474,250	278,348	4,052,710	80,805,308	61,927,580	142,732,888

Summary of Results: 2013 Low Stress Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
51.1	49.4	60%	7,295	38,026,450	38,878,717	-852,262	8,506	8,550	-43	3.3	10.7	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
23	323	47	862	61	243	89	-113	-2	155	1,687

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION $VC COST + 15% PREMIUM	AVERAGE GENERATION $VC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,942	332	-3	-43	15	3	75	2,649	7.02	300	243	542	1.43	3,211	8.45

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION $VC COST	AVERAGE GENERATION $VC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,290	413	1,703	4.48	300	243	542	1.43	2,246	5.91

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.0%	2,534

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
13,638,907	21,125,559	105,887,269	37%	62,740,640	113,102,598	541,079,176

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	10,477,764	5,307	4,067	10,654,039	21,133	6,334
ME	7,600,588	3,445	1,788	7,600,868	5,983	1,897
MA	19,920,954	36,462	11,182	19,944,056	36,541	11,191
NH	5,564,841	10,625	3,259	5,568,610	10,626	3,259
RI	4,265,577	37	740	4,318,770	82	755
VT	553,008	1	1	559,547	1	2
Total	48,402,774	55,877	21,036	48,589,889	72,266	23,439

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,365,460	615,590	3,001,050	38,878,390	38,026,450	13%	10%	3%	1,132,180	1,258,070	131,090,555
2,094,240	3,020,750	5,114,990	19,631,330	14,068,666						
1,761,790	968,010	2,749,800	43,921,330	68,992,625						
709,140	2,023,890	2,733,030	23,199,110	12,097,990						
94,230	0	94,230	10,071,670	13,189,124						
539,320	438,870	978,190	5,966,858	8,467,445						
7,584,180	7,087,110	14,671,290	141,648,688	154,842,300						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,365,460	615,590	17,091,580	2,478,380	14,565,820	34,690	1,706,680	16,307,380	22,571,010	38,878,390
ME	2,094,240	3,020,750	0	380,210	13,694,610	290	421,030	14,116,130	5,495,200	19,611,330
MA	1,761,790	968,010	5,597,860	5,277,220	28,501,120	28,920	1,766,410	30,296,450	13,624,880	43,921,330
NH	709,140	2,023,890	10,000,670	1,537,910	8,679,270	1,420	246,410	8,927,300	14,271,810	23,199,110
RI	94,230	0	0	0	9,780,900	196,540	0	9,977,440	94,230	10,071,670
VT	539,320	438,870	4,969,930	0	15,260	3,478	0	18,738	5,948,120	5,966,858
Total	7,584,180	7,087,110	37,660,240	9,673,720	75,237,180	265,338	4,140,530	79,643,438	62,005,250	141,648,688

Summary of Results: 2018 Low Stress Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
56.0	53.7	59%	8,123	41,761,644	49,033,651	-7,271,972	9,471	10,347	-875	3.1	10.9	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
154	375	73	1,253	195	366	19	-386	-32	156	2,173

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,337	347	-20	-46	15	3	77	3,128	7.47	116	366	482	1.15	3,682	8.63

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,651	413	2,064	4.94	116	366	482	1.15	2,546	6.10

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	3,455

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)	(MMBtu)	(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,702,591	36,169,041	185,299,497	53%	89,752,311	137,290,208	676,888,009

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	15,880,721	3,412	3,944	18,179,068	15,969	5,527
ME	8,973,218	1,786	1,673	8,973,547	2,221	1,782
MA	19,357,967	24,279	8,415	19,300,687	24,243	8,398
NH	4,868,757	6,823	2,305	4,875,962	6,825	2,307
RI	4,120,329	36	712	4,140,899	63	721
VT	515,245	2	2	522,117	4	4
Total	53,716,257	36,337	17,051	51,991,280	49,325	19,039

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,379,540	615,630	2,995,170	49,033,350	41,761,644	20%	17%	3%	1,211,190	1,172,940	261,477,956
2,011,540	3,020,750	5,032,290	23,508,960	15,433,413						
1,782,050	911,490	2,693,540	45,412,290	35,047,489						
697,490	2,024,700	2,722,190	22,472,190	13,563,067						
95,260	0	95,260	9,699,330	14,311,295						
494,590	438,960	933,550	6,032,850	9,251,557						
7,460,470	7,011,530	14,472,000	156,158,970	169,368,466						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,540	615,630	17,150,850	2,159,790	25,805,150	33,370	858,990	26,697,510	22,335,840	49,033,350
ME	2,011,540	3,020,750	0	304,780	18,049,970	330	121,590	18,171,890	5,337,070	23,508,960
MA	1,782,050	911,490	5,597,860	3,746,380	32,520,750	27,980	825,780	33,374,510	12,037,780	45,412,290
NH	697,490	2,024,700	10,000,870	1,073,230	8,637,250	4,540	34,110	8,675,900	13,796,290	22,472,190
RI	95,260	0	0	0	9,482,270	121,800	0	9,604,070	95,260	9,699,330
VT	494,590	438,960	5,074,090	0	16,440	8,370	0	25,210	6,007,640	6,032,850
Total	7,460,470	7,011,530	37,853,700	7,284,180	94,512,230	196,390	1,840,470	96,549,090	59,609,880	156,158,970

Summary of Results: 2018 Low Stress Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.7	53.8	59%	7,499	38,987,396	49,226,821	-10,239,386	8,743	10,347	-1,604	2.9	11.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
154	375	73	1,260	197	342	5	-535	-56	303	2,118

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,172	305	-10	-43	16	3	78	2,899	7.43	172	342	514	1.32	3,412	8.75

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,473	413	1,886	4.84	172	342	514	1.32	2,400	6.16

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.7%	4,276

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
26,361,403	36,458,758	186,509,355	53%	85,638,776	133,182,439	656,944,957

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	15,958,564	3,472	4,003	14,295,989	16,246	5,907
ME	8,247,666	2,008	1,597	8,248,261	2,444	1,706
MA	18,697,813	24,220	8,269	18,638,841	24,177	8,270
NH	5,028,391	7,089	2,391	5,035,841	7,091	2,393
RI	4,210,104	36	727	4,234,408	69	738
VT	514,032	2	2	521,003	3	4
Total	52,696,569	36,828	17,007	50,974,343	50,030	19,018

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,379,560	615,540	2,995,100	49,226,510	38,987,396	20%	17%	3%	1,211,190	1,172,960	237,313,519
2,011,630	3,020,750	5,032,380	21,656,030	15,433,413						
1,782,070	935,700	2,717,770	43,770,390	75,047,489						
697,550	2,024,610	2,722,160	22,793,760	13,563,067						
95,340	0	95,340	9,906,300	14,311,295						
494,600	438,880	933,480	6,032,091	9,251,557						
7,460,750	7,035,480	14,496,230	153,385,081	166,594,217						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,379,560	615,540	17,160,880	2,174,320	25,940,230	24,920	911,060	26,876,210	22,350,300	49,226,510
ME	2,011,630	3,020,750	0	327,620	16,148,860	610	146,560	16,296,030	5,360,000	21,656,030
MA	1,782,070	935,700	5,597,860	3,730,900	30,874,070	23,270	826,520	31,723,860	12,046,530	43,770,390
NH	697,550	2,024,610	10,000,870	1,101,560	8,910,880	4,120	54,170	8,969,170	13,824,590	22,793,760
RI	95,340	0	0	0	9,667,050	143,910	0	9,810,960	95,340	9,906,300
VT	494,600	438,880	5,074,090	0	17,360	7,061	0	24,521	6,007,570	6,032,091
Total	7,460,750	7,035,480	37,853,700	7,334,400	91,558,550	203,891	1,938,310	93,700,751	59,684,330	153,385,081

Summary of Results: 2018 Low Stress Scenario, Nuclear Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.2	52.5	59%	8,123	41,761,644	53,614,101	-11,852,414	9,471	10,947	-1,475	3.2	10.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
576	481	77	1,155	166	366	1	-592	-57	156	2,330

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,304	367	-18	-56	15	4	76	3,094	7.41	116	366	482	1.15	3,576	8.56

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,807	413	2,221	5.32	116	366	482	1.15	2,703	6.47

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,054

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
21,461,092	30,211,094	149,830,563	39%	80,326,741	125,859,637	609,995,696

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	13,725,943	3,350	3,558	12,071,707	15,681	5,404
ME	8,182,769	1,895	1,562	8,183,292	2,330	1,670
MA	18,197,609	23,542	8,055	18,140,527	23,501	8,037
NH	4,963,036	6,856	2,328	4,920,116	6,858	2,330
RI	4,060,136	35	701	4,064,178	67	712
VT	513,864	2	2	520,389	3	4
Total	49,643,377	35,680	16,206	47,970,209	48,440	18,157

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,367,490	614,730	2,982,220	53,613,760	41,761,644	20%	17%	3%	1,204,210	1,168,060	262,806,345
2,011,090	3,020,760	5,031,850	21,523,110	15,433,413						
1,781,940	897,990	2,679,930	42,741,528	75,047,489						
697,370	2,024,620	2,721,990	22,692,660	13,563,067						
95,000	0	95,000	9,558,770	14,311,295						
494,570	438,860	933,430	6,031,204	9,251,557						
7,447,460	6,996,960	14,444,420	156,161,032	169,368,466						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total MOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,367,490	614,730	26,864,210	2,109,800	20,765,370	27,790	864,380	21,657,530	11,956,230	53,613,760
ME	2,011,090	3,020,760	0	311,250	16,039,270	520	140,220	16,180,010	5,343,100	21,523,110
MA	1,781,940	897,990	5,597,860	3,629,810	30,018,210	20,568	795,150	30,833,928	11,907,600	42,741,528
NH	697,370	2,024,620	10,000,870	1,066,090	8,448,670	4,370	50,670	8,903,710	13,788,950	22,692,660
RI	95,000	0	0	0	9,321,410	142,360	0	9,463,770	95,000	9,558,770
VT	494,570	438,860	5,074,090	0	16,730	6,954	0	23,684	6,007,550	6,031,204
Total	7,447,460	6,996,960	47,537,038	7,116,950	85,009,660	202,552	1,850,420	87,062,632	69,098,480	156,161,032

Summary of Results: 2018 Low Stress Scenario, Coal Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
55.2	52.5	59%	8,123	41,761,644	53,614,101	-11,852,414	9,471	10,947	-1,475	3.2	10.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
351	414	114	1,318	293	366	1	-592	-57	156	2,364

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,304	367	-18	-56	15	4	76	3,894	7.41	116	366	482	1.15	3,576	8.56

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
1,942	413	2,355	5.40	116	366	482	1.15	2,737	6.55

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,054

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
21,461,092	30,211,094	149,830,563	39%	80,326,741	125,859,637	609,995,696

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	21,859,555	3,350	3,558	20,205,319	15,681	5,404
ME	8,182,769	1,895	1,562	8,183,292	2,330	1,670
MA	18,197,609	23,542	4,955	18,140,527	23,501	9,037
NH	4,963,056	6,856	2,328	4,970,116	6,858	2,330
RI	4,060,136	35	701	4,064,178	67	712
VT	513,864	2	2	520,389	3	4
Total	57,776,989	35,680	16,206	56,103,821	48,440	18,157

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,367,490	614,730	2,982,220	53,613,760	41,761,644	20%	17%	3%	1,204,210	1,160,060	262,006,345
2,011,090	3,020,760	5,031,850	21,523,110	15,433,413						
1,781,940	897,990	2,679,930	42,741,528	75,047,489						
697,370	2,024,620	2,721,990	22,692,660	13,563,067						
95,000	0	95,000	9,558,770	14,311,295						
494,570	438,860	933,430	6,031,204	9,251,557						
7,447,460	6,996,960	14,444,420	156,161,032	169,368,466						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,367,490	614,730	17,189,880	11,405,797	20,765,370	27,780	864,380	21,657,530	31,568,897	53,226,427
ME	2,011,090	3,020,760	0	311,250	16,039,270	520	140,220	16,180,010	5,343,100	21,523,110
MA	1,781,940	897,990	5,597,860	3,629,810	30,018,210	20,568	795,150	30,833,928	11,907,600	42,741,528
NH	697,370	2,024,620	10,000,870	1,066,090	8,838,670	4,370	50,670	8,903,710	13,788,950	22,692,660
RI	95,000	0	0	0	9,321,410	142,360	0	9,463,770	95,000	9,558,770
VT	494,570	438,860	5,074,090	0	16,730	6,954	0	23,684	6,007,520	6,031,204
Total	7,447,460	6,996,960	37,853,708	16,412,947	85,009,660	202,552	1,850,420	87,062,632	68,711,067	155,773,699

Summary of Results: 2030 Low Stress Scenario, Conventional Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
63.0	59.5	58%	9,196	46,957,157	57,762,259	-10,805,061	10,722	12,147	-1,424	4.2	9.8	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
286	428	94	1,682	406	360	12	-622	-72	156	2,729

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,956	542	-56	-55	9	12	69	3,599	8.52	116	360	476	1.01	4,475	9.53

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,213	413	2,626	5.59	116	360	476	1.01	3,102	6.61

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,806

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
39,907,048	50,211,323	253,920,189	62%	128,140,768	178,065,648	865,779,996

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,661,318	2,126	3,775	16,977,449	9,246	4,925
ME	9,870,330	1,791	1,816	9,875,861	2,258	1,929
MA	21,819,971	19,694	7,983	21,799,364	19,820	7,664
NH	4,885,860	7,591	2,477	4,906,371	7,545	2,473
RI	5,414,269	47	935	5,416,219	49	936
VT	2,198,169	39	283	2,213,381	43	288
Total	62,869,917	31,478	17,168	61,188,645	38,941	18,314

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,521,650	617,290	3,138,940	57,761,940	46,957,157	25%	20%	3%	1,253,270	1,373,170	275,929,945
2,103,560	3,021,980	5,125,540	25,672,330	17,993,893						
1,759,760	884,970	2,644,730	52,647,100	85,671,306						
673,360	2,060,250	2,733,610	22,252,980	16,767,908						
90,230	0	90,230	12,926,880	16,261,026						
570,830	443,740	1,014,570	9,916,030	10,728,869						
7,719,390	7,028,230	14,747,620	181,177,260	194,380,658						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,521,650	617,290	17,180,600	1,408,310	35,757,900	42,520	233,470	36,033,890	21,728,050	57,761,940
ME	2,103,560	3,021,980	0	293,750	20,110,100	4,980	138,160	20,253,040	5,419,290	25,672,330
MA	1,759,760	884,970	5,597,860	3,177,020	40,774,050	30,080	423,360	41,227,490	11,419,610	52,647,100
NH	673,360	2,060,250	9,912,000	1,205,300	9,171,910	23,520	6,460	9,400,990	12,851,990	22,252,980
RI	90,230	0	0	0	12,825,120	11,530	0	12,836,650	90,230	12,926,880
VT	570,830	443,740	5,014,570	0	3,818,180	69,710	0	3,888,890	6,029,140	9,916,030
Total	7,719,390	7,028,230	37,705,918	6,084,780	121,656,360	181,140	801,450	122,638,950	58,538,310	181,177,260

Summary of Results: 2030 Low Stress Scenario, DSM-Focus Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
61.2	58.8	59%	8,489	43,837,798	57,363,167	-13,525,327	9,898	12,147	-2,249	4.5	9.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
266	428	93	1,663	403	336	2	-773	-122	232	2,548

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,685	539	-22	-51	9	11	66	3,722	8.49	172	336	509	1.16	4,230	9.65

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST		TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)		($Mil)	(¢/kWh)
1,979	413	2,392	5.46	172	336	509	1.16		2,901	6.62

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.2%	4,936

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation		ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)		(MMBtu)		(MMBtu)
38,901,062	49,276,887	250,461,408	62%		123,616,131	173,137,582	841,629,803

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	18,520,997	2,235	3,799	16,926,174	9,539	4,962
ME	9,884,605	1,721	1,804	9,490,376	2,167	1,916
MA	21,432,299	21,005	8,061	21,415,175	20,962	8,049
NH	4,947,909	7,763	2,526	4,956,975	7,717	2,521
RI	4,713,334	41	814	4,716,493	45	815
VT	2,229,942	40	289	2,245,002	43	293
Total	**61,729,065**	**32,804**	**17,293**	**60,660,195**	**40,474**	**18,457**

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,521,900	617,470	3,139,370	57,162,830	43,837,798	23%	20%	3%	1,253,510	1,273,180	251,994,406
2,103,860	3,022,460	5,126,320	25,727,960	17,993,893						
1,759,960	919,490	2,679,450	51,430,500	85,671,906						
673,850	2,059,540	2,733,390	22,361,570	16,767,908						
90,320	0	90,320	11,177,290	16,261,026						
570,950	443,440	1,014,390	9,992,030	10,728,869						
7,720,840	**7,062,400**	**14,783,240**	**178,052,180**	**191,261,380**						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,521,900	617,470	17,180,600	1,412,150	35,292,330	27,380	311,000	35,630,710	21,532,120	57,162,830
ME	2,103,860	3,022,460	0	294,990	20,181,390	4,990	120,270	20,306,650	5,421,310	25,727,960
MA	1,759,960	919,490	5,597,860	3,361,150	39,284,530	28,940	474,570	39,792,040	11,638,460	51,430,500
NH	673,850	2,059,540	9,912,060	1,235,920	8,452,160	21,740	5,480	8,479,380	13,882,190	22,361,570
RI	90,320	0	0	0	11,068,170	18,800	0	11,086,970	90,320	11,177,290
VT	570,950	443,440	5,014,570	0	3,894,100	69,970	0	3,963,070	6,028,960	9,992,030
Total	**7,720,840**	**7,062,400**	**37,705,918**	**6,304,210**	**118,176,680**	**170,820**	**911,320**	**119,258,820**	**58,793,360**	**178,052,180**

Summary of Results: 2030 Low Stress Scenario, Nuclear Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
60.1	56.4	58%	9,196	46,957,157	62,630,438	+15,673,237	10,722	13,047	-2,324	5.4	8.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
730	542	99	1,576	354	360	0	-844	-151	156	2,823

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen in Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM ($Mil)	AVERAGE GENERATION SVC COST + 15% PREMIUM (¢/kWh)	Adder for DSM Programs ($Mil)	RPS Cost (RECs + ACPs) ($Mil)	TOTAL SYSTEM BENEFITS COST ($Mil)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($Mil)	AVG COST (¢/kWh)
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)								
2,823	697	-52	-68	8	18	60	4,909	8.54	116	360	476	1.01	4,485	9.55

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,306	413	2,720	5.79	116	360	476	1.01	3,196	6.81

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
19.3%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
34,249,389	44,257,537	221,050,184	50%	116,892,038	166,033,155	799,814,214

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	16,464,549	1,765	3,271	14,877,564	8,162	4,229
ME	9,842,987	1,786	1,811	9,848,318	2,230	1,923
MA	20,720,622	19,292	7,564	20,708,266	19,362	7,576
NH	4,900,956	7,633	2,489	4,921,053	7,606	2,489
RI	4,546,507	40	792	4,546,507	40	792
VT	2,130,394	38	272	2,144,642	41	276
Total	58,646,016	30,672	16,220	57,046,332	37,441	17,285

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,490,220	615,320	3,105,540	62,630,090	46,957,157	23%	20%	3%	1,234,560	1,260,430	276,979,809
2,102,520	3,022,870	5,125,390	25,611,820	17,993,893						
1,759,440	853,000	2,612,440	50,031,590	35,671,405						
672,610	2,060,800	2,733,410	22,277,280	16,767,908						
89,950	0	89,950	10,887,940	16,261,026						
569,940	443,560	1,013,500	9,751,690	10,728,869						
7,684,680	6,995,550	14,680,230	181,190,410	194,380,658						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	2,490,220	615,320	26,863,930	1,254,500	31,171,340	40,660	194,720	31,406,120	31,223,970	62,630,090
ME	2,102,520	3,022,870	0	307,190	20,055,490	4,620	119,130	20,179,240	5,432,580	25,611,820
MA	1,759,440	853,000	5,597,860	3,083,120	38,282,980	28,460	426,730	38,738,170	11,293,420	50,031,590
NH	672,610	2,060,800	9,912,000	1,217,660	8,389,490	22,490	1,350	8,413,330	13,863,950	22,277,280
RI	89,950	0	0	0	10,797,990	0	0	10,797,990	89,950	10,887,940
VT	569,940	443,560	5,014,570	0	3,657,120	66,500	0	3,723,620	6,028,070	9,751,690
Total	7,684,680	6,995,550	47,389,240	5,862,470	112,354,410	162,130	741,930	113,258,470	67,931,940	181,190,410

Summary of Results: 2030 Low Stress Scenario, Coal Solution
Degree of New England East-West Solution Excludes Central Connecticut Reliability Components

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.08 loss grossup	Total Energy Needed to Meet Customer Load	Total Generation In Connecticut	Net Imports	CT LSEs' ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
60.1	56.4	58%	9,196	46,957,157	62,630,438	-15,673,237	10,722	13,047	-2,324	5.4	8.6	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Capital Carrying Costs on New (Unplanned) Generation in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	RPS Cost (RECs + ACPs)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)
505	475	135	1,741	574	360	0	-844	-151	156	2,952

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Spin	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,823	697	-52	-68	8	18	60	4,809	8.54	116	360	476	1.01	4,485	9.55

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generators	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	RPS Cost (RECs + ACPs)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	($Mil)	($Mil)	(¢/kWh)	($Mil)	(¢/kWh)
2,436	412	2,849	6.07	116	360	476	1.01	3,325	7.08

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
18.3%	4,906

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
34,249,389	44,257,537	221,050,184	50%	116,892,038	166,033,155	799,814,214

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	24,598,161	1,785	3,271	25,011,176	8,162	4,229
ME	9,842,987	1,786	1,811	9,848,318	2,230	1,923
MA	20,720,622	19,392	7,584	20,708,266	19,362	7,576
NH	4,900,956	7,633	2,489	4,921,033	7,606	2,489
RI	4,566,507	40	792	4,566,507	40	792
VT	2,130,394	38	272	2,144,642	41	276
Total	66,779,628	30,672	16,220	65,219,944	37,441	17,285

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
2,490,220	615,320	3,105,540	62,630,090	46,957,157	23%	20%	3%	1,234,560	1,260,430	276,978,909
2,102,520	3,022,870	5,125,390	25,611,820	17,993,893						
1,759,440	853,000	2,612,440	50,031,590	35,671,806						
672,610	2,060,800	2,733,410	22,277,280	16,767,908						
89,950	0	89,950	10,887,940	10,261,026						
569,940	443,560	1,013,500	9,751,690	10,726,869						
7,684,680	6,995,550	14,680,230	181,190,410	194,380,658						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,490,220	615,320	17,160,600	10,550,497	31,171,240	40,060	194,720	31,406,120	30,836,637	62,242,757
ME	2,102,520	3,022,870	0	307,190	20,055,490	4,620	119,130	20,179,240	5,432,580	25,611,820
MA	1,759,440	853,000	5,597,860	3,083,120	38,282,980	28,460	426,730	38,738,170	11,293,420	50,031,590
NH	672,610	2,060,800	9,912,860	1,217,660	8,389,490	22,490	1,350	8,413,330	13,863,950	22,277,280
RI	89,950	0	0	0	10,797,990	0	0	10,797,990	89,950	10,887,940
VT	569,940	443,560	5,014,570	0	3,657,120	66,500	0	3,723,620	6,028,070	9,751,690
Total	7,684,680	6,995,550	37,705,918	15,158,467	112,354,410	162,130	741,930	113,258,470	67,544,607	180,803,077

APPENDIX I: SECTION 51 of PA 07-242

Sec. 51. (NEW) (*Effective from passage*) (a) The electric distribution companies, in consultation with the Connecticut Energy Advisory Board, established pursuant to section 16a-3 of the general statutes, as amended by this act, shall review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.

(b) On or before January 1, 2008, and annually thereafter, the companies shall submit to the Connecticut Energy Advisory Board an assessment of (1) the energy and capacity requirements of customers for the next three, five and ten years, (2) the manner of how best to eliminate growth in electric demand, (3) how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods, (4) the impact of current and projected environmental standards, including, but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals and how different resources could help achieve those standards and goals, (5) energy security and economic risks associated with potential energy resources, and (6) the estimated lifetime cost and availability of potential energy resources.

(c) Resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. The projected customer cost impact of any demand-side resources considered pursuant to this subsection shall be reviewed on an equitable bases with nondemand-side resources. The procurement plan shall specify (1) the total amount of energy and capacity resources needed to meet the requirements of all customers, (2) the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs, (3) needs for generating capacity and transmission and distribution improvements, (4) how the development of such resources will reduce and stabilize the costs of electricity to consumers, and (5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.

(d) The procurement plan shall consider: (1) Approaches to maximizing the impact of demand-side measures; (2) the extent to which generation needs can be met by renewable and combined heat and power facilities; (3) the optimization of the use of generation sites and generation portfolio existing within the state; (4) fuel types, diversity, availability, firmness of supply and security and environmental impacts thereof, including impacts on meeting the state's greenhouse gas emission goals; (5) reliability, peak load and energy forecasts, system contingencies and existing resource availabilities; (6) import limitations and the appropriate reliance on such imports; and (7) the impact of the procurement plan on the costs of electric customers.

(e) The board, in consultation with the regional independent system operator, shall review and approve or review, modify and approve the proposed procurement plan as submitted not later than one hundred twenty days after receipt. For calendar years 2009 and thereafter, the board shall conduct such review not later than sixty days after receipt. For the purpose of reviewing the plan, the Commissioners of Transportation and Agriculture and the chairperson of the Public

Utilities Control Authority, or their respective designees, shall not participate as members of the board. The electric distribution companies shall provide any additional information requested by the board that is relevant to the consideration of the procurement plan. In the course of conducting such review, the board shall conduct a public hearing, may retain the services of a third-party entity with experience in the area of energy procurement and may consult with the regional independent system operator. The board shall submit the reviewed procurement plan, together with a statement of any unresolved issues, to the Department of Public Utility Control. The department shall consider the procurement plan in an uncontested proceeding and shall conduct a hearing and provide an opportunity for interested parties to submit comments regarding the procurement plan. Not later than one hundred twenty days after submission of the procurement plan, the department shall approve, or modify and approve, the procurement plan. For calendar years 2009 and thereafter, the department shall approve, or modify and approve, said procurement plan not later than sixty days after submission.

(f) On or before September 30, 2009, and every two years thereafter, the Department of Public Utility Control shall report to the joint standing committees of the General Assembly having cognizance of matters relating to energy and the environment regarding goals established and progress toward implementation of the procurement plan established pursuant to this section, as well as any recommendations for the process.

(g) All electric distribution companies' costs associated with the development of the resource assessment and the development of the procurement plan shall be recoverable through the systems benefits charge.

APPENDIX J: SCOPE OF SERVICES

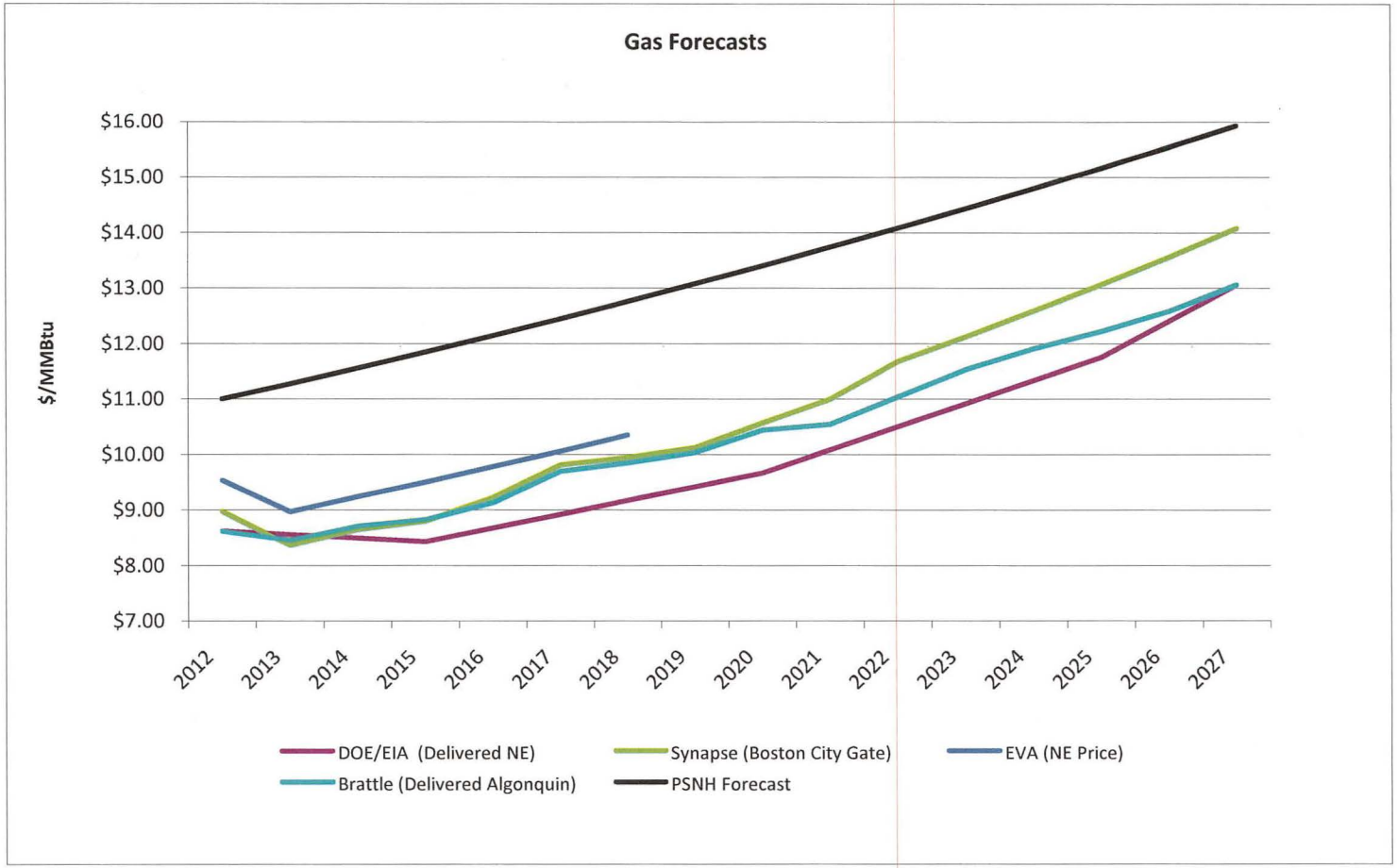
Subject to the joint direction from the United Illuminating Company (UI) and The Connecticut Light and Power Company (CL&P), review the State of Connecticut energy and capacity resource assessment and develop a comprehensive plan (the Plan) for the procurement of energy resources as required by Section 51 of Public Act Number 07-242 (the Act). In addition to the work proposed in Consultant's response to the Request for Proposal dated July 23, 2007 and pursuant to the Act, Consultant shall develop a Plan that includes but is not limited to the following:

1. Review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.
2. Assess and provide detailed reporting on the energy and capacity requirements of customers for the next three, five and ten years; and extend the analyses and assess required/recommended resources for the timeframe required to substantially demonstrate the long term impact of various potential solutions (said timeframe shall not be less than 20 years).
3. Assess and report on the manner of how best to eliminate growth in electric demand.
4. Assess how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods.
5. Assess and report on the impact of current and projected environmental standards, including, but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals and how different resources could help achieve those standards and goals.
6. Assess and report on energy security and economic risks associated with potential energy resources.
7. Assess and report on the estimated lifetime cost and availability of potential energy resources.
8. Consider approaches to maximizing the impact of demand-side measures.
9. Consider the extent to which generation needs can be met by renewable and combined heat and power facilities.
10. Consider the optimization of the use of generation sites and generation portfolio existing within the state.
11. Consider fuel types, diversity, availability, firmness of supply and security and environmental impacts thereof, including impacts on meeting the state's greenhouse gas emission goals.
12. Consider reliability, peak load and energy forecasts, system contingencies and existing resource availabilities.
13. Consider import limitations and the appropriate reliance on such imports.
14. Consider the impact of the procurement plan on the costs of electric customers.
15. Resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. The projected customer cost impact of any demand-side resources considered pursuant to this subsection shall be reviewed on an equitable bases with nondemand-side resources.
16. Specify the total amount of energy and capacity resources needed to meet the requirements of all customers.
17. Specify the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs

18. Specify needs for generating capacity and transmission and distribution improvements. Note that UI and CL&P will perform some of the work and provide inputs related to the referenced distribution improvements.
19. Specify how the development of such resources will reduce and stabilize the costs of electricity to consumers.
20. Specify the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.
21. Compare various solutions on a cost-of-service/revenue requirement basis, for all relevant future scenarios.
22. Compare various solutions based on predicted/resulting market revenues, including: wholesale Locational Marginal Pricing (LMP*), FCM, LFRM, and ancillary services; for all relevant future scenarios.

    *LMP shall mean the hourly price for energy, congestion, and marginal losses at a node.
23. Forecast resulting retail prices**, i.e. Generation Service Charge (GSC) for each proposed solution for all relevant future scenarios under both of the following regimens:
    a. Market-based pricing (non-dedicated resources, marginal based pricing).
    b. Cost of service based pricing (dedicated resources, supplied at cost).

    **Retail price (also referred to as generation service charge, GSC): full requirements load following power supply priced at the customer's meter, including but not limited to changing hourly energy requirements, capacity, operating reserves (forward pool-wide, forward local and spinning), automatic generation control, uplift charges allocated to energy market loads, ISO charges, NEPOOL charges, supplier administration costs, and the costs of managing the various risks and uncertainties attendant to serving load with retail choice.
24. Assess the relative influence of all factors on predicted outcomes.
25. Assess the robustness of various possible/proposed solutions; including but not limited to subjecting each/all solutions to multiple future conditions/scenarios, and rating the performance of the possible solutions using an agreed upon weighting of measures of merit.
26. Deliver to UI and CL&P in both detailed written and electronic form:
    a. Inputs
    b. Assumptions
    c. Outputs
    d. Modeling bases
    e. Detailed descriptions of the inputs, outputs, each model's mechanics, and the process used to integrate the various components and development of the results.
    f. Identification of likely ranges for all inputs and outputs and provide assessments of uncertainty related to the same.
    g. Basis for combinations of factors used to develop the relevant future scenarios, and an explanation of any known or suspected correlations between factors.
27. Deliver to UI and CL&P interim work products, presentations, draft reports, and final reports as specified in Exhibit B, Schedule.
28. Provide ongoing consultation, testimony, analysis, revisions, and defense of the Plan in conjunction with the CEAB submittal and review scheduled to commence on January 1, 2008.
29. Provide ongoing consultation, testimony, analysis, revisions, and defense of the Plan in conjunction with the DPUC submittal and review scheduled to commence no later than 120 days after January 1, 2008.



ATTACHMENT 20

Public Service Company of New Hampshire
Docket No. DE 11-250

Date Request Received: 09/16/2013 **Date of Response: 11/14/2013**
Request No. DEPOSITION-004 **Page 1 of 5**
Request from: TransCanada

Witness: Gary A. Long

Request:
Who prepared the $11 per MMBtu price assumption that appears in Deposition Exhibit 9, Part E, page 15? Please provide any underlying materials relied upon by the person preparing the MMBtu price in the report.

Response:
The referenced $11 per MMBtu price assumption was based on actual reported Natural Gas Prices for dispatch at PSNH generating units at the time the analysis was performed (2008), as prepared by the NU Fuel Purchasing Department, rather than any specific forecast. The $11 was assumed to continue until 2012, after which it was escalated at 2.5%. Forecasts available at the time (including those relied upon by FERC Staff in its presentation to the FERC Commissioners dated June 19, 2008, which are included in Deposition Exhibit 9 at Bates pages 21 and 22) support the base assumption and escalation, but were not used directly nor relied upon in preparing the referenced MMBtu price.

NEW HAMPSHIRE UNITS ONLY
INCLUDES SO2 ADDER

15-Jan-08 Reported Nepool Price

Note: Dollars per Barrel, Dollars per Ton, Dollars per MBtu
calculate the Replacement $/MBtu.

				Sulfur	w/o ADDER Delivd	Btu	Replace. $/MBtu	HeatRate. Btu/kWh	w/o adders $/MBtu	Nom. $/MWh	
498											
557	Schiller 5	Coal		0.62	69.36	13,122	3.203	11,172	2.643	$35.79	
558	Schiller 6	Coal		0.62	69.36	13,122	3.187	10,998	2.643	$35.05	
556	Schiller 4	Coal		0.62	69.36	13,122	3.187	11,041	2.643	$35.19	
490	Merrimack 2	Coal		1.24	82.8	13,046	3.637	9,682	3.173	$35.21	
489	Merrimack 1	Coal		1.34	77.91	13,422	3.315	9,721	2.902	$32.23	
481											
508	Newington blend	oil/gas		100%oil&0	11.66		12.064	10,793	11.656	$130.21	
480											
397											
481											
390											
391											
390											
480											
493											
493											
520											
519											
508	Newington	Oil		1.09	76.44	156,149	12.058	10,793	11.656	**$130.14**	
508	Newington	Gas			11		11	10,793	11	$118.72	
390											
391											
493											
493											
481											
480											
494											
494											
556	Schiller	Oil		1.09	76.44	156,149	12.066	10,887	11.656	$131.36	
557	Schiller 5 NWP	Wood		0	31	4,274	4.078	13,078	3.627	$0.00	****
482											

	NOX Adder/ MBtu		Fuel Add'tve	Fuel Unload	Fuel Handle	Ash/Slag Dispose	Maint Costs	So2 Adder	Oper. Adj.	NX-4 Adders	Per A. Dall 09/21//2004 ; effective 09/22//2004 Date Changed
Newington	0	Oil	0.1968	0	0.0757	0.31	0.054	2.0003		2.6368	27-Sep-05
Schiller	0	Oil	0.14	0.05	0.05	0.35	0.1	2.0003		2.6903	28-Jan-93
Merrimack	0	Coal	0	0	1.0088	1.3546	0.9673	7.758		11.0886	28-Aug-07
Merrimack	0	Coal	0.3924	0	1.0306	2.5038	0.9882	7.175		12.09	28-Aug-07
Schiller 4	0	Coal	0.359	1.87	1.87	5.5	1.0847	3.595		14.2787	24-Jul-06
Schiller 5	0	Coal	0	1.87	1.87	6.2835	1.0847	3.595		14.7032	24-Jul-06
Schiller 6	0	Coal	0.359	1.87	1.87	5.5	1.0847	3.595		14.2787	24-Jul-06
Schiller 5		Wood	1.355	1.25	1.25					3.855	17-May-06
Newington	0	Gas	Included in $/MWh is an inefficiency rate of 3.7%								

$289.00 per ton SO2 - Allowance Price
$520.00 per ton SO2 - Allowance Market Price (Newington)
$0.00 per ton NOX - Allowance Market Price (Newigton)
$0.00 per ton NOX - Emission Rate

**** The NWPP dispatch price is inclusive of a production tax credit of $10/MWh and realized (and forecast) REC revenue of approximately $50/MWh. (The dispatch price without REC and PTC = $53.33/MWh.)

NEW HAMPSHIRE UNITS ONLY
INCLUDES SO2 ADDER

15-Feb-08 Reported Nepool Price

Note: Dollars per Barrel, Dollars per Ton, Dollars per MBtu calculate the Replacement $/MBtu.

				Sulfur	w/o ADDER Delivd	Btu	Replace. $/MBtu	HeatRate. Btu/kWh	w/o adders Nom. $/MBtu	$/MWh
498										
557	Schiller 5	Coal		0.63	80.5	13,077	3.643	11,172	3.078	$40.70
558	Schiller 6	Coal		0.63	80.5	13,077	3.626	10,998	3.078	$39.88
556	Schiller 4	Coal		0.63	80.5	13,077	3.626	11,041	3.078	$40.04
490	Merrimack 2	Coal		1.2	86.83	13,054	3.78	9,682	3.326	$36.60
489	Merrimack 1	Coal		1.72	80.3	13,419	3.486	9,721	2.992	$33.89
481										
508	Newington blend	oil/gas		100%oil&0	11.16		11.518	10,793	11.16	$124.32
480										
397										
481										
390										
391										
390										
480										
493										
493										
520										
519										
508	Newington	Oil		1.09	73.19	156,149	~~11.512~~	10,793	11.16	**$124.25**
508	Newington	Gas			10.96		10.96	10,793	10.96	$118.29
390										
391										
493										
493										
481										
480										
494										
494										
556	Schiller	Oil		1.09	73.19	156,149	11.52	10,887	11.16	$125.42
557	Schiller 5 NWP	Wood		0	31	4,274	4.078	13,078	3.627	$0.00 ****
482										

	NOX Adder/ MBtu		Fuel Add'tve	Fuel Unload	Fuel Handle	Ash/Slag Dispose	Maint Costs	So2 Adder	Oper. Adj.	NX-4 Adders	Per A. Dall 09/21//2004 : effective 09/22//2004 Date Changed
Newington	0	Oil	0.1968	0	0.0757	0.31	0.054	1.6724		2.3089	27-Sep-05
Schiller	0	Oil	0.14	0.05	0.05	0.35	0.1	1.6724		2.3624	28-Jan-93
Merrimack	0	Coal	0	0	1.0088	1.3546	0.9673	9.93		13.2606	28-Aug-07
Merrimack	0	Coal	0.3924	0	1.0306	2.5038	0.9882	6.944		11.859	28-Aug-07
Schiller 4	0	Coal	0.359	1.87	1.87	5.5	1.0847	3.662		14.3457	24-Jul-06
Schiller 5	0	Coal	0	1.87	1.87	6.2835	1.0847	3.662		14.7702	24-Jul-06
Schiller 6	0	Coal	0.359	1.87	1.87	5.5	1.0847	3.662		14.3457	24-Jul-06
Schiller 5		Wood	1.355	1.25	1.25					3.855	17-May-06
Newington	0	Gas	Included in $/MWh is an inefficiency rate of 3.7%								

$289.00 per ton SO2 - Allowance Price
$435.00 per ton SO2 - Allowance Market Price (Newington)
$0.00 per ton NOX - Allowance Market Price (Newigton)
$0.00 per ton NOX - Emission Rate

**** The NWPP dispatch price is inclusive of a production tax credit of $10/MWh and realized (and forecast) REC revenue of approximately $50/MWh. (The dispatch price without REC and PTC = $53.33/MWh.)

NEW HAMPSHIRE UNITS ONLY
INCLUDES SO2 ADDER

14-Mar-08 Reported Nepool Price

Note: Dollars per Barrel, Dollars per Ton, Dollars per MBtu
calculate the Replacement $/MBtu.

				Sulfur	w/o ADDER Delivd	Btu	Replace. $/MBtu	HeatRate. Btu/kWh	w/o adders Nom. $/MBtu	$/MWh	
498											
557	Schiller 5	Coal		0.64	72.25	13,163	3.307	11,172	2.744	$36.95	
558	Schiller 6	Coal		0.64	72.25	13,163	3.291	10,998	2.744	$36.20	
556	Schiller 4	Coal		0.64	72.25	13,163	3.291	11,041	2.744	$36.34	
490	Merrimack 2	Coal		1.2	86.83	13,054	3.78	9,682	3.326	$36.60	
489	Merrimack 1	Coal		1.37	80.87	13,473	3.418	9,721	3.001	$33.22	
481											
508	Newington blend	oil/gas		100%oil&0	11.34		11.701	10,793	11.343	$126.29	
480											
397											
481											
390											
391											
390											
480											
493											
493											
520											
519											
508	Newington	Oil		1.09	74.39	156,149	~~11.695~~	10,793	11.343	**$126.23**	
508	Newington	Gas			10.81		10.81	10,793	10.81	$116.67	
390											
391											
493											
493											
481											
480											
494											
494											
556	Schiller	Oil		1.09	74.39	156,149	11.703	10,887	11.343	$127.42	
557	Schiller 5 NWP	Wood		0	31	4,274	4.078	13,078	3.627	$0.00	****
482											

Per A. Dall 09/21//2004
effective 09/22//2004

	NOX Adder/ MBtu		Fuel Add'tve	Fuel Unload	Fuel Handle	Ash/Slag Dispose	Maint Costs	So2 Adder	Oper. Adj.	NX-4 Adders	Date Changed
Newington	0	Oil	0.1968	0	0.0757	0.31	0.054	1.6724		2.3089	27-Sep-05
Schiller	0	Oil	0.14	0.05	0.05	0.35	0.1	1.6724		2.3624	28-Jan-93
Merrimack	0	Coal	0	0	1.0088	1.3546	0.9673	7.895		11.2256	28-Aug-07
Merrimack	0	Coal	0.3924	0	1.0306	2.5038	0.9882	6.944		11.859	28-Aug-07
Schiller 4	0	Coal	0.359	1.87	1.87	5.5	1.0847	3.712		14.3957	24-Jul-06
Schiller 5	0	Coal	0	1.87	1.87	6.2835	1.0847	3.712		14.8202	24-Jul-06
Schiller 6	0	Coal	0.359	1.87	1.87	5.5	1.0847	3.712		14.3957	24-Jul-06
Schiller 5		Wood	1.355	1.25	1.25					3.855	17-May-06
Newington	0	Gas	Included in $/MWh is an inefficiency rate of 3.7%								

$289.00 per ton SO2 - Allowance Price
$435.00 per ton SO2 - Allowance Market Price (Newington)
$0.00 per ton NOX - Allowance Market Price (Newigton)
$0.00 per ton NOX - Emission Rate

**** The NWPP dispatch price is inclusive of a production tax credit of $10/MWh and realized (and forecast) REC revenue of approximately $50/MWh. (The dispatch price without REC and PTC = $53.33/MWh.)

NEW HAMPSHIRE UNITS ONLY
INCLUDES SO2 ADDER

15-Apr-08 Reported Nepool Price

Note: Dollars per Barrel, Dollars per Ton, Dollars per MBtu calculate the Replacement $/MBtu.

				Sulfur	w/o ADDER Delivd	Btu	Replace. $/MBtu	HeatRate. Btu/kWh	w/o adders Nom. $/MBtu	$/MWh
498										
557	Schiller 5	Coal		0.66	70.07	13,163	3.229	11,172	2.662	$36.07
558	Schiller 6	Coal		0.66	70.07	13,163	3.212	10,998	2.662	$35.33
556	Schiller 4	Coal		0.66	70.07	13,163	3.212	11,041	2.662	$35.47
490	Merrimack 2	Coal		1.2	88.16	13,064	3.827	9,682	3.374	$37.06
489	Merrimack 1	Coal		1.28	82.5	13,509	3.452	9,721	3.054	$33.56
481										
508	Newington blend	oil/gas		100%oil&0	12.46		12.772	10,793	12.464	$137.85
480										
397										
481										
390										
391										
390										
480										
493										
493										
520										
519										
508	Newington	Oil		1.09	81.74	156,149	12.766	10,793	12.464	**$137.78**
508	Newington	Gas			11.25		11.25	10,793	11.25	$121.42
390										
391										
493										
493										
481										
480										
494										
494										
556	Schiller	Oil		1.09	81.74	156,149	12.774	10,887	12.464	$139.07
557	Schiller 5 NWP	Wood		0	31	4,274	4.078	13,078	3.627	$0.00 ****
482										

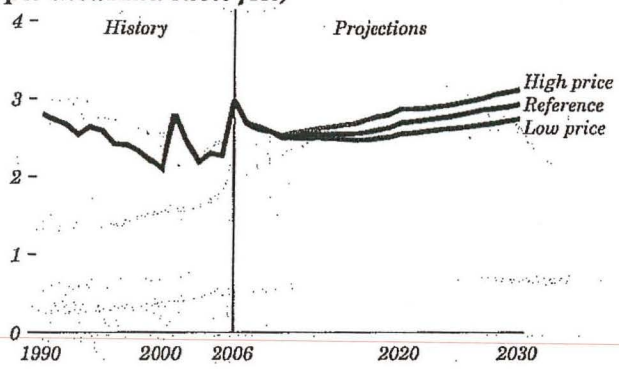
	NOX Adder/ MBtu		Fuel Add'tve	Fuel Unload	Fuel Handle	Ash/Slag Dispose	Maint Costs	So2 Adder	Oper. Adj.	NX-4 Adders	Per A. Dall 09/21//2004 at 9:00 A.M. effective 09/22//2004 Date Changed	NOX Adde Em. Rate	NOX Adders 0
Newington	0	Oil	0.1968	0	0.0757	0.31	0.054	1.3444		1.9809	27-Sep-05		0.21
Schiller	0	Oil	0.14	0.05	0.05	0.35	0.1	1.3444		2.0344	28-Jan-93		0.3
Merrimack	0	Coal	0	0	1.0088	1.3546	0.9673	7.43		10.7606	28-Aug-07		0.15
Merrimack	0	Coal	0.3924	0	1.0306	2.5038	0.9882	6.924		11.839	28-Aug-07		0.15
Schiller 4	0	Coal	0.359	1.87	1.87	5.5	1.0847	3.817		14.5007	24-Jul-06		0
Schiller 5	0	Coal	0	1.87	1.87	6.2835	1.0847	3.817		14.9252	24-Jul-06		0
Schiller 6	0	Coal	0.359	1.87	1.87	5.5	1.0847	3.817		14.5007	24-Jul-06		0
Schiller 5		Wood	1.355	1.25	1.25					3.855	17-May-06		
Newington	0	Gas	Included in $/MWh is an inefficiency rate of 3.7%										0.15

$289.00 per ton SO2 - Allowance Price
$350.00 per ton SO2 - Allowance Market Price (Newington)
$0.00 per ton NOX - Allowance Market Price (Newigton)
$0.00 per ton NOX - Emission Rate

**** The NWPP dispatch price is inclusive of a production tax credit of $10/MWh and realized (and forecast) REC revenue of approximately $50/MWh. (The dispatch price without REC and PTC = $53.33/MWh.)

Transmission and Distribution Margins Vary Inversely With Volumes

Figure 79. Average natural gas transmission and distribution margins, 1990-2030 (2006 dollars per thousand cubic feet)

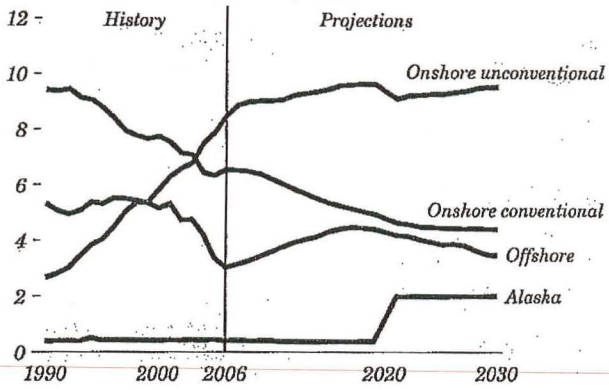


The transmission and distribution margin for natural gas delivered to end users is the difference between the average delivered price and the average source price, which is the quantity-weighted average of the lower 48 wellhead price and the average import price. It reflects both the capital and operating costs for pipelines and the volume of natural gas transported. Although operating costs vary with the level of pipeline utilization, capital costs are fixed for the most part. Variations in pipeline throughput result in higher or lower transmission and distribution costs per thousand cubic feet of natural gas transported. Thus, because the high and low price case projections show the greatest variation in total natural gas consumption, the greatest variation in transmission and distribution margins is also seen in those cases.

In the high price case, total natural gas consumption in 2030 is projected to be only 21.9 trillion cubic feet. As a result, the average transmission and distribution margin for delivered natural gas is projected to increase from $2.98 per thousand cubic feet in 2006 to $3.12 per thousand cubic feet in 2030 (2006 dollars). In the low price case, total natural gas consumption in 2030 grows to 24.8 trillion cubic feet, and the average transmission and distribution margin in 2030 drops to $2.74 per thousand cubic feet as the existing pipeline system is used at a higher capacity factor. In the reference case, with projected natural gas consumption of 22.7 trillion cubic feet in 2030, the projected average transmission and distribution margin in 2030 is $2.93 per thousand cubic feet (Figure 79).

Unconventional Production Is a Growing Source of U.S. Gas Supply

Figure 80. Natural gas production by source, 1990-2030 (trillion cubic feet)



Total U.S. natural gas production grows modestly in the reference case, from 18.5 trillion cubic feet in 2006 to 19.4 trillion cubic feet in 2030, as depletion of the onshore lower 48 conventional resource base is offset by increased production from unconventional sources and from Alaska. Offshore production increases from 3.0 trillion cubic feet in 2006 to 4.5 trillion cubic feet in 2017, then declines to 3.5 trillion cubic feet in 2030. Production in shallow waters declines slowly through 2030. Production in deeper waters rises to 3.0 trillion cubic feet in 2019 and then declines through 2030.

A large proportion of the onshore lower 48 conventional natural gas resource base has been discovered. Discoveries of new conventional natural gas reservoirs are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Accordingly, total lower 48 onshore conventional natural gas production declines in the *AEO2008* reference case from 6.6 trillion cubic feet in 2006 to 4.4 trillion cubic feet in 2030 (Figure 80). Incremental production of lower 48 onshore natural gas comes primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. Lower 48 unconventional production increases in the reference case from 8.5 trillion cubic feet in 2006 to 9.5 trillion cubic feet in 2030.

The Alaska natural gas pipeline is expected to begin transporting natural gas to the lower 48 States in 2020. As a result, Alaska's natural gas production increases from 0.4 trillion cubic feet in 2006 to 2.0 trillion cubic feet in 2030 in the reference case.

IHS CERA Alert®

AMERICA'S NATURAL GAS REVOLUTION

by Daniel Yergin and Robert Ineson

The following is an Opinion column that appeared in *The Wall Street Journal* on November 3, 2009.

DATE
November 5, 2009

A "shale gale" of unconventional and abundant US gas is transforming the energy market.

DANIEL YERGIN, Chairman of IHS CERA, is author of *The Prize, The Quest for Oil, Money, and Power,* now in a new edition, and *Commanding Heights: The Battle for the World Economy.*

ROBERT INESON is IHS CERA Senior Director, Global Gas.

The biggest energy innovation of the decade is natural gas—more specifically what is called "unconventional" natural gas. Some call it a revolution.

Yet the natural gas revolution has unfolded with no great fanfare, no grand opening ceremony, no ribbon cutting. It just crept up. In 1990 unconventional gas—from shales, coalbed methane, and so-called tight formations—was about 10 percent of total US production. Today it is around 40 percent and growing fast, with shale gas by far the biggest part.

The potential of this "shale gale" only really became clear around 2007. In Washington, DC, the discovery has come later—only in the past few months. Yet it is already changing the national energy dialogue and overall energy outlook in the United States—and could change the global natural gas balance.

From the time of the California energy crisis at the beginning of this decade, it appeared that the United States was headed for an extended period of tight supplies, even shortages, of natural gas.

While gas has many favorable attributes—as a clean, relatively low-carbon fuel—abundance did not appear to be one of them. Prices had gone up, but increased drilling failed to bring forth additional supplies. The United States, it seemed, was destined to become much more integrated into the global gas market, with increasing imports of liquefied natural gas (LNG).

But a few companies were trying to solve a perennial problem: how to liberate shale gas—the plentiful natural gas supplies locked away in the impermeable shale. The experimental lab was a sprawling area called the Barnett Shale in the environs of Fort Worth, Texas.

The companies were experimenting with two technologies. One was horizontal drilling. Instead of merely drilling straight down into the

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resource, horizontal wells go sideways after a certain depth, opening up a much larger area of the resource-bearing formation.

The other technology is known as hydraulic fracturing, or "fraccing." Here, the producer injects a mixture of water and sand at high pressure to create multiple fractures throughout the rock, liberating the trapped gas to flow into the well.

The critical but little-recognized breakthrough was early in this decade—finding a way to meld together these two increasingly complex technologies to finally crack the shale rock and thus crack the code for a major new resource. It was not a single eureka moment, but rather the result of incremental experimentation and technical skill. The success freed the gas to flow in greater volumes and at a much lower unit cost than previously thought possible.

In the past few years the revolution has spread into other shale plays, from Louisiana and Arkansas to Pennsylvania and New York State, and British Columbia as well.

The supply impact has been dramatic. In the US Lower 48, states thought to be in decline as a natural gas source, production surged an astonishing 15 percent from the beginning of 2007 to mid-2008. This increase is more than most other countries produce in total.

Equally dramatic is the effect on US reserves. Proved reserves have risen to 245 trillion cubic feet (Tcf) in 2008 from 177 Tcf in 2000, despite having produced nearly 165 Tcf during those years. The recent increase in estimated US gas reserves by the Potential Gas Committee, representing both academic and industry experts, is in itself equivalent to more than half of the total proved reserves of Qatar, the new LNG powerhouse. With more drilling experience, US estimates are likely to rise dramatically in the next few years. At current levels of demand, the United States has about 90 years of proved and potential supply—a number that is bound to go up as more and more shale gas is found.

To have the resource base suddenly expand by this much is a game changer. But what is getting changed?

It transforms the debate over generating electricity. The US electric power industry faces very big questions about fuel choice and what kind of new generating capacity to build. In the face of new climate regulations, the increased availability of gas will likely lead to more natural gas consumption in electric power because of gas's relatively lower carbon dioxide emissions. Natural gas–fired power plants can also be built more quickly than coal-fired plants.

Some areas such as Pennsylvania and New York, traditionally importers of the bulk of their energy from elsewhere, will instead become energy producers. It could also mean that more buses and truck fleets will be converted to natural gas. Energy-intensive manufacturing companies, which have been moving overseas in search of cheaper energy in order to remain globally competitive, may now stay home.

But these industrial users and the utilities with their long investment horizons—both of which have been whipsawed by recurrent cycles of shortage and surplus in natural gas over several decades—are inherently skeptical and will require further confirmation of a sustained shale gale before committing.

More abundant gas will have another, not so well recognized effect: facilitating renewable development. Sources like wind and solar are "intermittent." When the wind doesn't blow and

the sun doesn't shine, something has to pick up the slack, and that something is likely to be natural gas–fired electric generation. This need will become more acute as the mandates for renewable electric power grow.

So far only one serious obstacle to development of shale resources across the United States has appeared: water. The most visible concern is the fear in some quarters that hydrocarbons or chemicals used in fraccing might flow into aquifers that supply drinking water. However, in most instances, the gas-bearing and water-bearing layers are widely separated by thousands of vertical feet, as well as by rock, with the gas being much deeper.

Therefore, the hydraulic fracturing of gas shales is unlikely to contaminate drinking water. The risks of contamination from surface handling of wastes, common to all industrial processes, requires continued care. Though fraccing uses a good deal of water, it is actually less water-intensive than many other types of energy production.

Unconventional natural gas has already had a global impact. With the US market now oversupplied, and storage filled to the brim, there's been much less room for LNG. As a result more LNG is going into Europe, leading to lower spot prices and talk of modifying long-term contracts.

But is unconventional natural gas going to go global? Preliminary estimates suggest that shale gas resources around the world could be equivalent to or even greater than current proved natural gas reserves. Perhaps much greater. But here in the United States our independent oil and gas sector, open markets, and private ownership of mineral rights facilitated development. Elsewhere development will require negotiations with governments and potentially complex regulatory processes. Existing long-term contracts, common in much of the natural gas industry outside the United States, could be another obstacle. Extensive new networks of pipelines and infrastructure will have to be built. And many parts of the world still have ample conventional gas to develop first.

Yet interest and activity are picking up smartly outside North America. A shale gas revolution in Europe and Asia would change the competitive dynamics of the globalized gas market, altering economic calculations and international politics.

This new innovation will take time to establish its global credentials. The United States is really only beginning to grapple with the significance. It may be half a decade before the strength of the unconventional gas revolution outside North America can be properly assessed. But what has begun as the shale gale in the United States could end up being an increasingly powerful wind that blows through the world economy. ■

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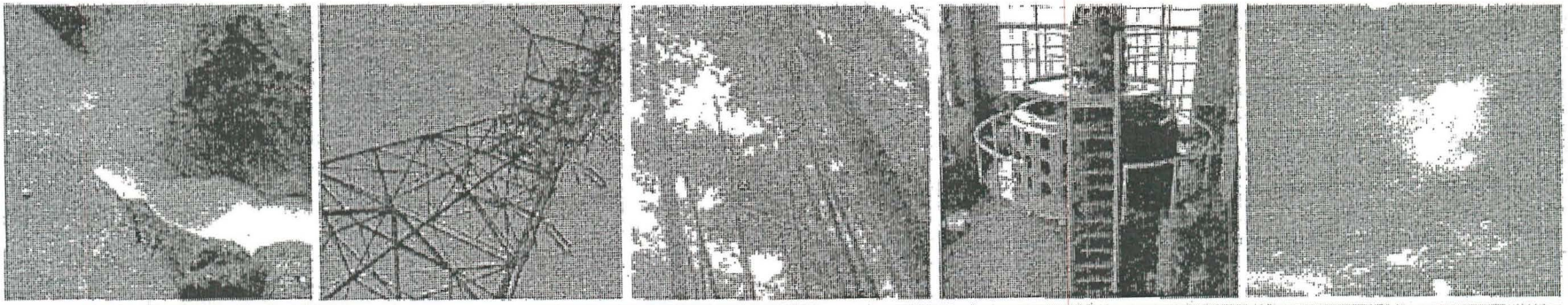
Witness: Gary A. Long
Request from: TransCanada

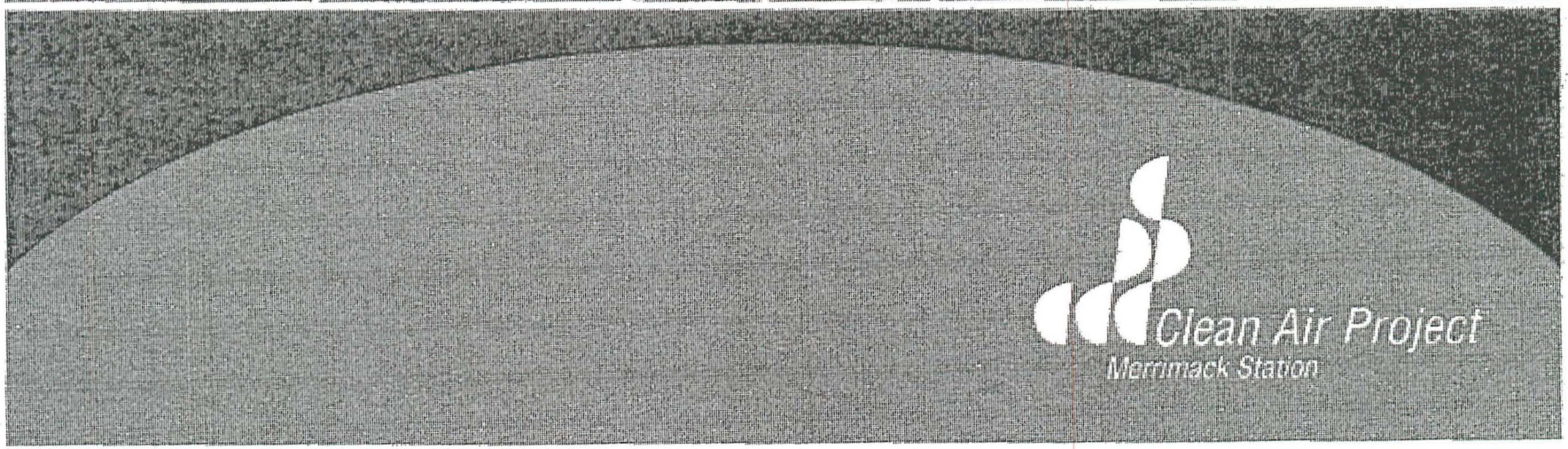
Question:
Reference the attached 31 page power point from the legislative history of SB 152 from the 2009 session of the NH Legislature, who produced this document ? By whom was this person or persons employed ? Who testified before the Legislature on this power point ?

Response:
The document was produced through a collaborative effort of several people at PSNH. Gary A. Long testified before the legislature on this topic, although his testimony did not present this document in significant detail; rather, the document was provided to legislators and referred to during Mr. Long's testimony.

THE BRIDGE TO NEW HAMPSHIRE'S CLEAN ENERGY FUTURE

Public Service of New Hampshire
The Northeast Utilities System





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Today's Agenda

- The Clean Air Project
- Cost
- Project Benefits
- Senate Bill 152
- The Bridge to NH's Clean Energy Future

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Merrimack Station in Bow

- **New Hampshire's workhorse**
  - Base load power plant that operates 24/7
  - Coal-fired
  - 433 MW net output
  - Enough energy for 190,000 NH households
    - » 35% of PSNH's generation mix
  - Meets or exceeds all environmental regulations
    - » 20 years of progress guided by state and federal clean power laws (NH Clean Power Act, RGGI, Mercury Law)

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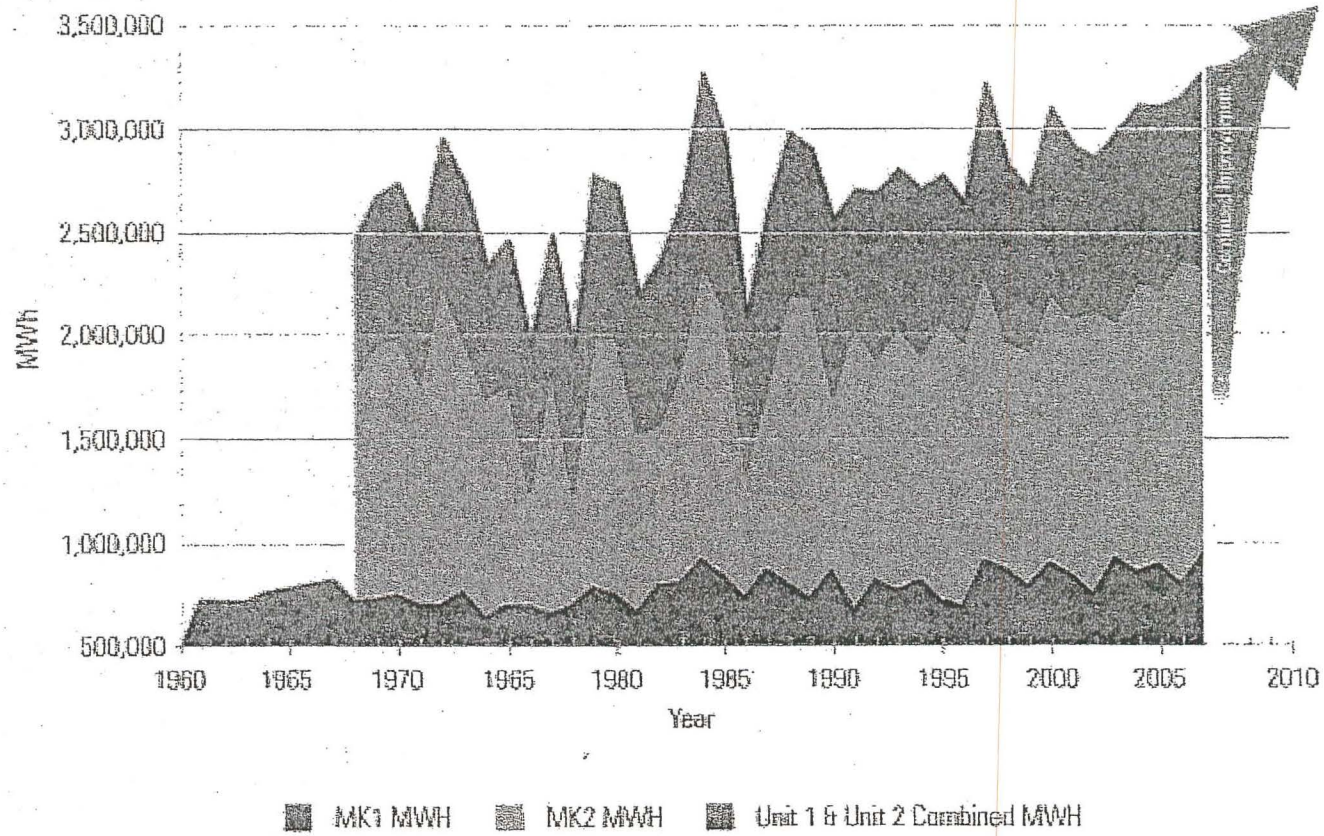
Merrimack Station is Running Better than Ever

PSNH customers have invested millions over the years to upgrade equipment and maintain Merrimack Station in top operating condition.



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New Hampshire's Blueprint for Lowering Emissions: The 2002 Clean Power Act

	NO_X	**85% Reduction – 1995/2000** Achieved through installation of groundbreaking Selective Catalytic Reduction system
	Mercury	**80% Reduction or Better – 2013 or sooner** Required under the Mercury law that was passed in 2006
	SO_X	**90% Reduction or Better – 2013 or sooner** A benefit of the Mercury law that was passed in 2006
	CO_2	**Stabilized emissions through 2014: 10% reduction from 2015 – 2018** RGGI legislation passed in 2008

Ground-breaking emissions reductions achieved through forward-looking legislation, careful implementation, and staying the course.

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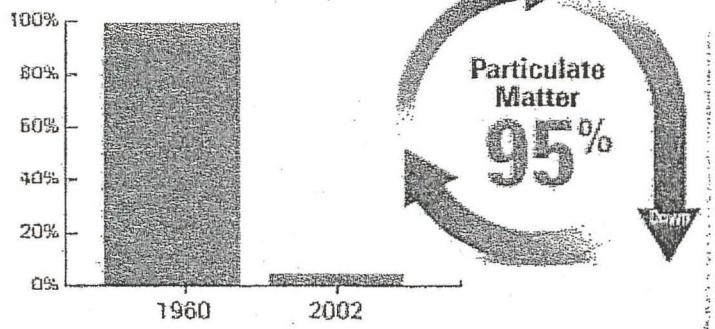
Emissions Control Technologies Installed at Merrimack Station: 20 Years of Progress

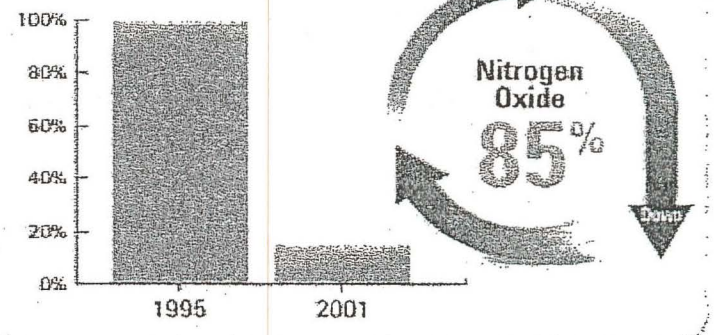
Electrostatic Precipitators

* Installed in 1960 &1968
* Installed supplemental equipment in 1989 & 1999

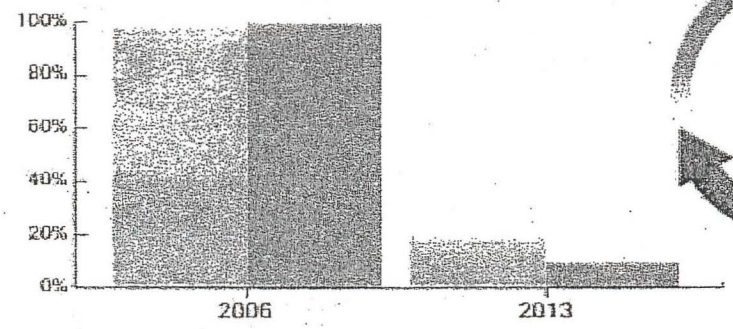


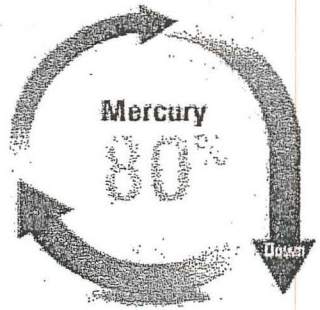
Selective Catalytic Reduction System

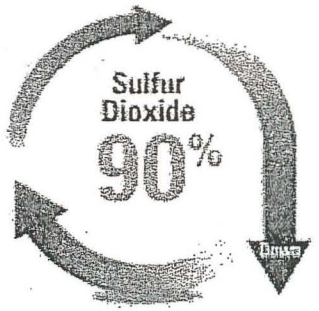
* Installed in 1995 & 1999
* Augmented in 1998, 2000 & 2001



Clean Air Project: Wet Scrubber







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Status of the Clean Air Project

- In a 2006 law, the NH Legislature mandated that a scrubber be installed as soon as possible, but no later than July 2013
- Even without the state law, the scrubber will be needed to meet impending federal emissions requirements
- PSNH is currently halfway through the six-year project
- $230 million (over half of the cost to engineer and build the scrubber) has been spent or contractually committed
  - This cost will have to be recovered from PSNH customers whether or not the scrubber installation is completed

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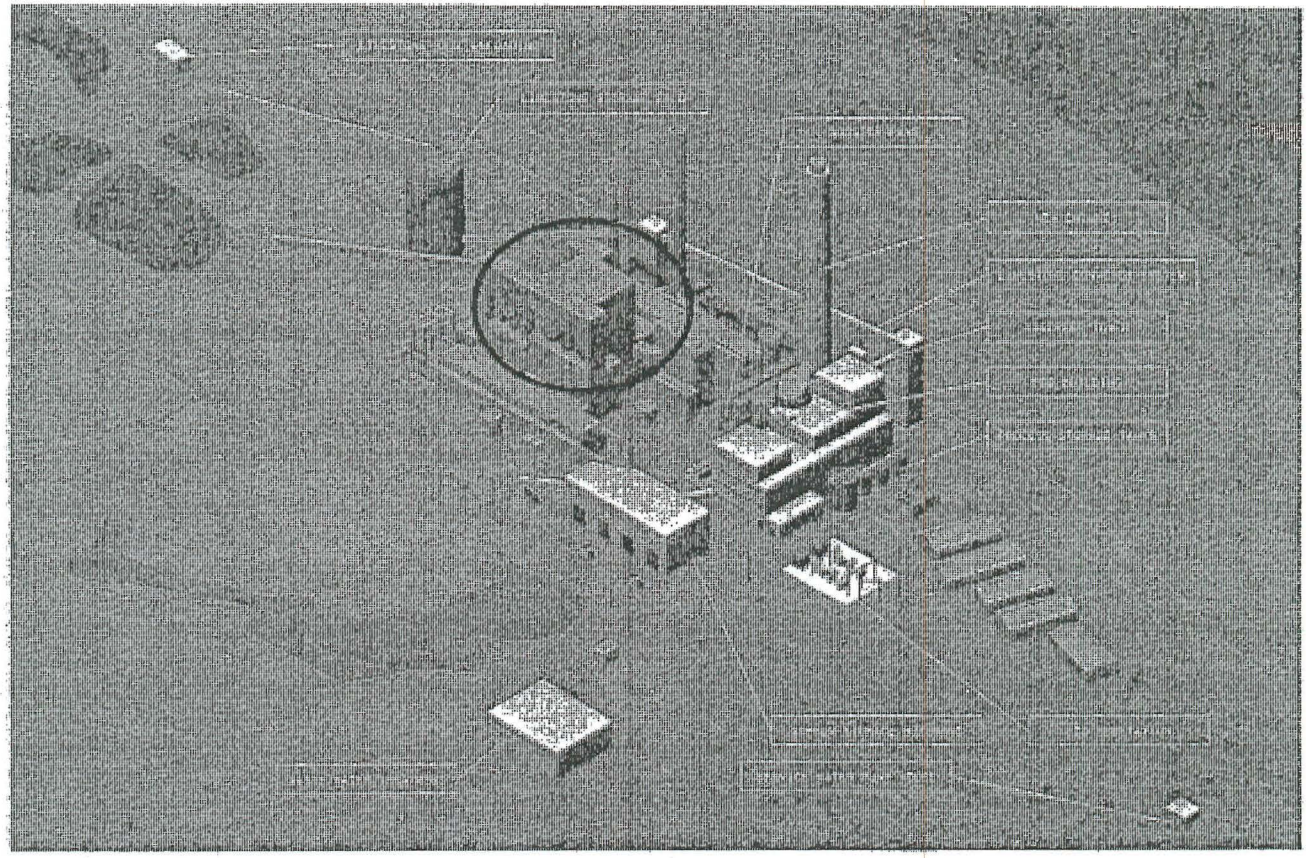
Understanding the Scope of the Clean Air Project
Merrimack Station: 2012



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Project Schedule

Project	2006	2007	2008	2009	2010	2011	2012
NH Mercury Reduction Act	▲						
Preliminary Engineering	▪▪▪▪▪▪▪▪▪						
Program Manager Hired		▲					
Detailed Engineering		▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪					
Major Contracts Awarded			▪▪▪				
Major Permitting		▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪					
Preliminary Site Prep.			▪▪▪▪▪				
Major Construction (underway)				▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪▪			
Testing & Commissioning						▪▪▪▪▪	
In Service							▲

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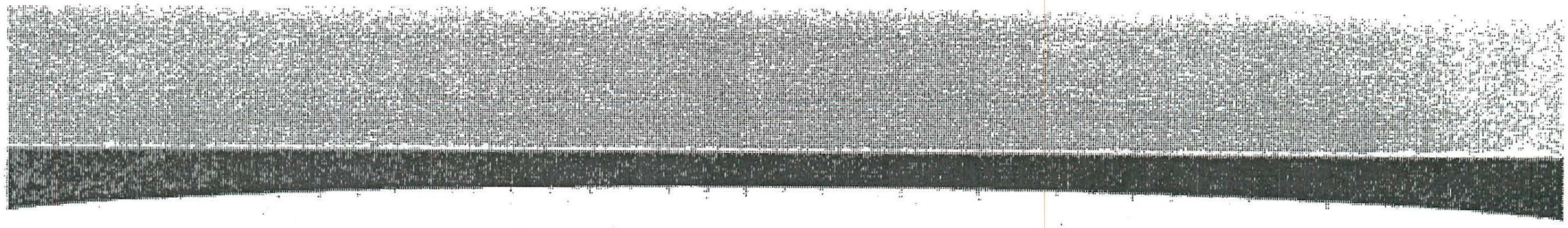

COST

2005 / 2008 Cost Comparison

Project Components	**2008** (firm price contracts)	**2005** (initial estimates)
5 Major Contracts • Scrubber system, chimney, material handling system, wastewater treatment facility, program manager	**$213M**	$149M
Balance of Contracts and Materials • Ductwork, foundations, booster fans and motors, electrical, site work, etc.	**$135M**	$48M
Owners Costs • Project financing, insurance, NU labor, and overhead costs	**$80M**	$35M
Escalation and Contingency	**$29M**	$18M
TOTAL	**$457M**	$250M

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Three Major Drivers of Cost Increase

- **Economic and Commodity Volatility**
  - Significant cost increases reflective of national and world economy
  - Increased financing costs
- **Site Specific Factors**
  - Scrubber must guarantee 85% mercury reduction
  - Two power generation units of differing size must connect into one scrubber system
- **Progression from Initial Estimate Phase to Design Phase**
  - Firm price performance-based contracts with vendor guarantees have replaced initial estimated pricing
  - Majority of project design completed, replacing preliminary engineering used to determine initial estimates

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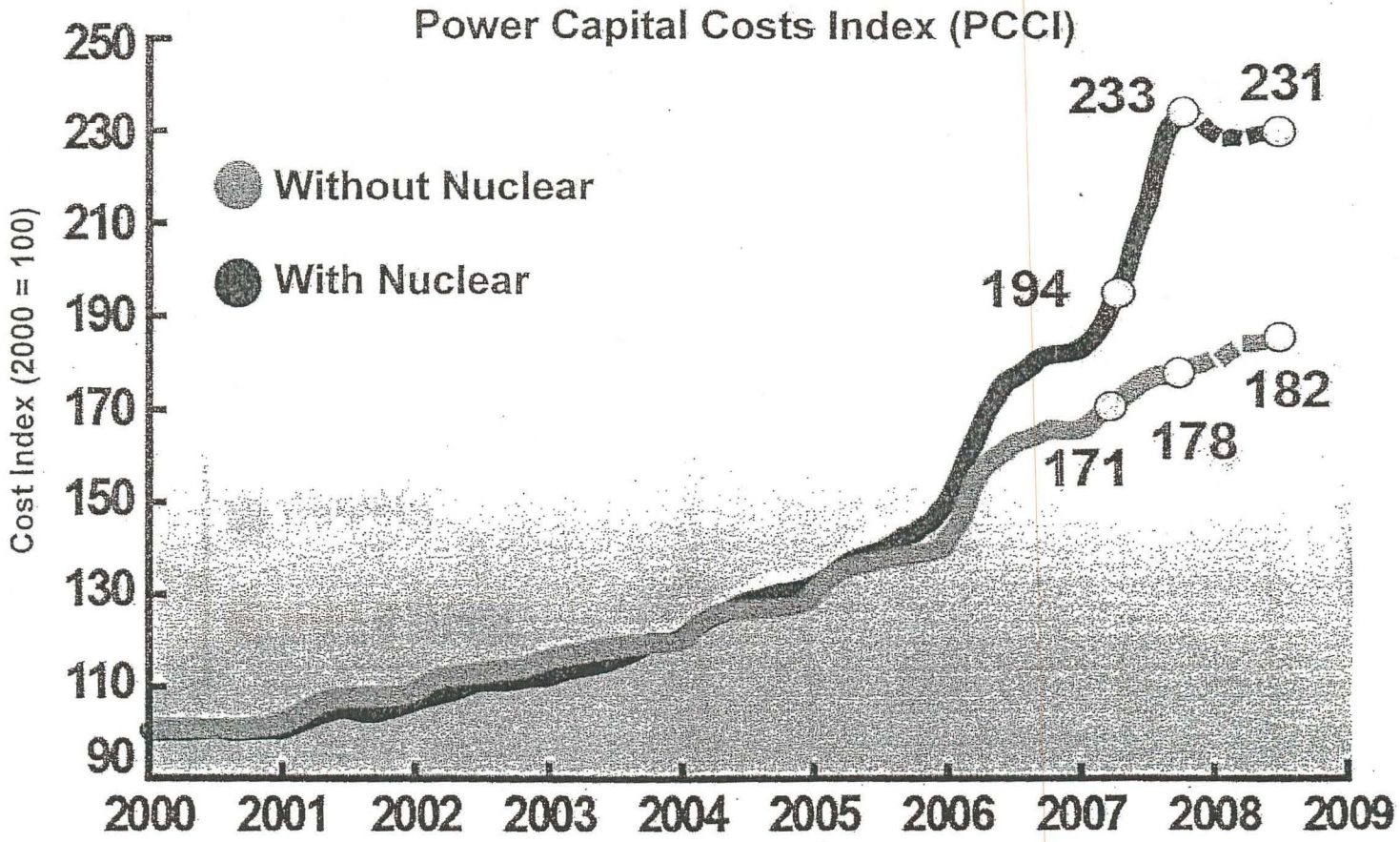
Capital Costs Increased Significantly



Source: Cambridge Energy Research Associates. 71023-12

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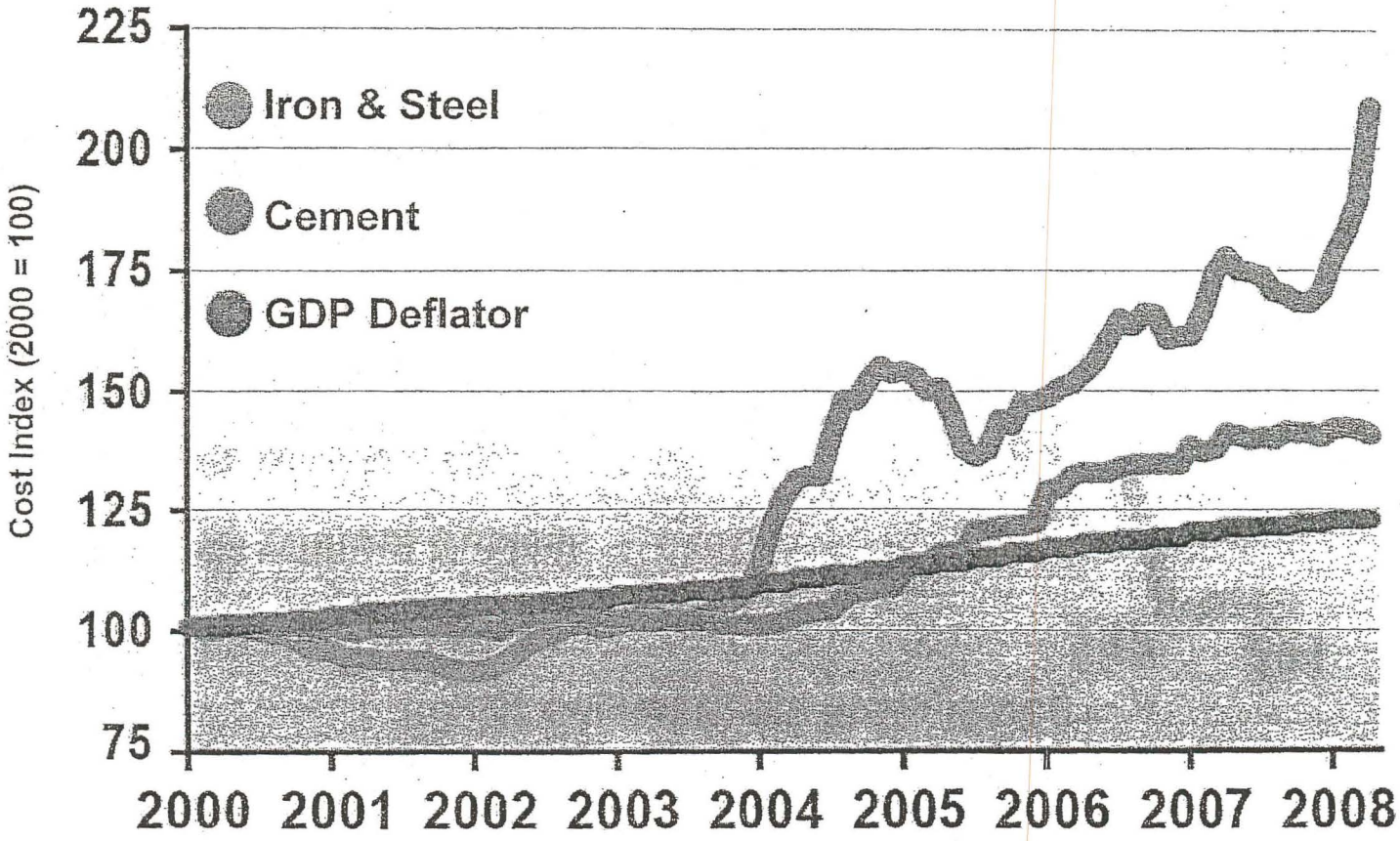
Primary Construction Costs



Source: Derived from Bureau of Labor Statistics Data and Bureau of Economic Analysis Data

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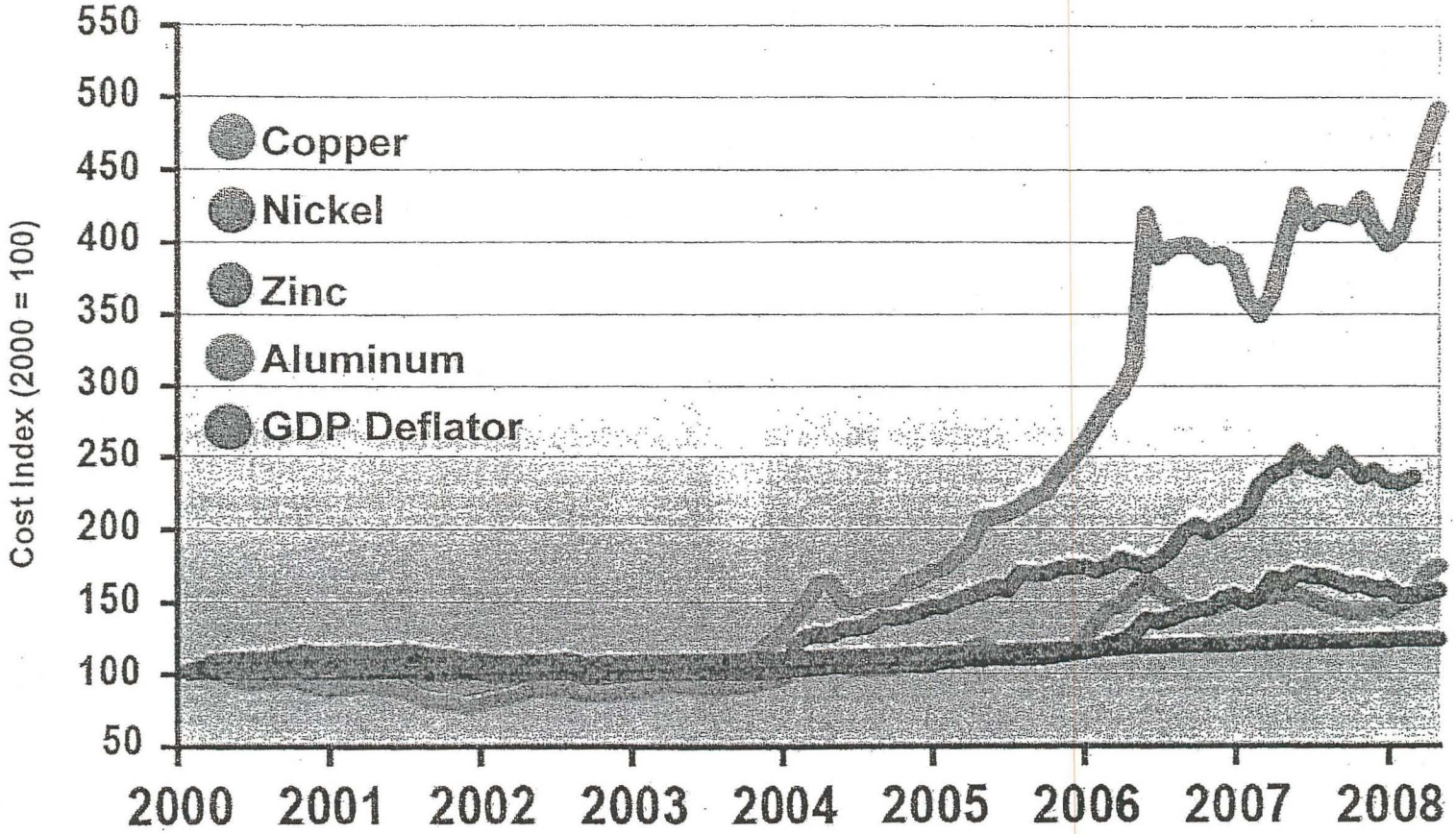
Secondary Construction Costs



Source: Derived from Bureau of Labor Statistics Data and Bureau of Economic Analysis Data

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Overview of Cost Increase: From Estimate to Implementation

2005: $250 million

- Preliminary estimate for generic scrubber
- Requirements for aggressive 85% mercury reduction and 2013 completion date were not yet established by Legislature
- Based on study performed by national engineering firm Sargent & Lundy, with additions for contingencies by PSNH
- Reflects market conditions in early 2005
- Reflects inability to forecast the highly volatile global market environment that emerged between 2005 and 2008

2008: $457 million

- Confirmed cost for a scrubber that is required to reduce mercury emissions by 85% (one of the first in the nation)
- Includes guarantee from vendors for 85% mercury reduction
- Based on highly detailed engineering specs and firm price contracts for major components
- Reflects realities of market conditions in 2008 (including the cost of financing)
- Comparable with other multiple-unit scrubber installations now occurring elsewhere in the country
  - Reaffirmed by independent firm Power Advocate, Inc. in March of 2009

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PSNH's Approach Is Designed to Reduce Customer Risk

- Cost risks for major components put on vendors, not customers
  - Obtained firm price contracts for "critical path" components with long lead times
  - Developed strict performance criteria, and required performance guarantees from vendors
- At every step of the way, we have affirmed pricing to ensure it is in line with marketplace
  - Independent firms retained to provide market analysis and price benchmarking in 2005, 2006, 2007, 2008, and 2009
  - Confirmed project costs are consistent with market prices for projects of similar scope and size
- Delayed subcontracts when possible to take advantage of opportunities for better price negotiations

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Customer Cost Safety Nets

- PSNH has legally binding, firm price contracts in place for major components of project
- When the project is complete, the NH Public Utilities Commission will scrutinize every dollar spent on the project before any money can be recovered from customers through PSNH's rates
- PSNH customers (esp. commercial customers) can switch to a different energy supplier at any time to avoid paying costs associated with the scrubber
- The bottom line:
  - Installation of the scrubber at $457M continues to be a better option for PSNH customers than purchasing replacement energy in the open market

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PROJECT BENEFITS

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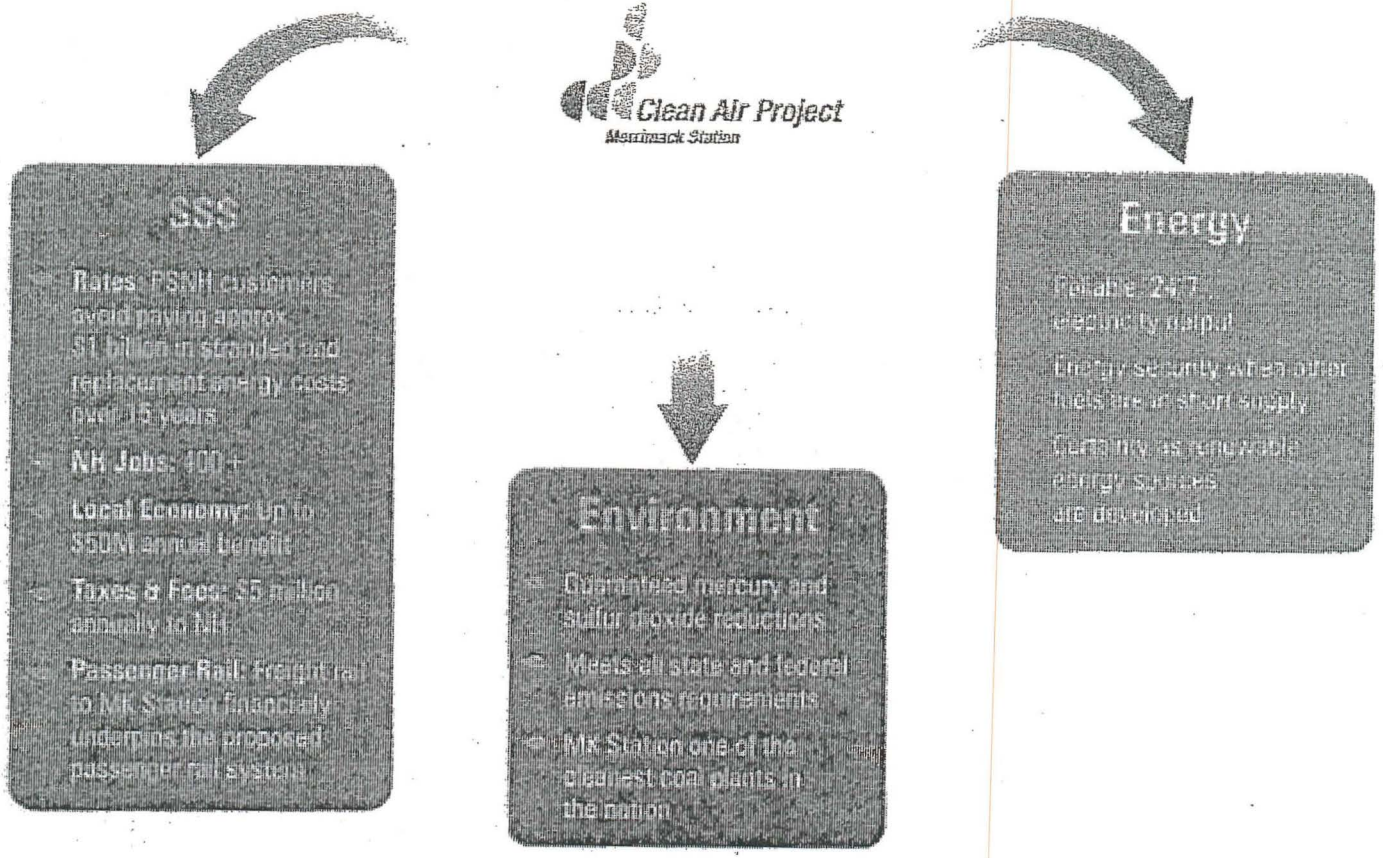
Project Benefits



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SENATE BILL 152

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Impact of Senate Bill 152

- No bill is necessary to understand the cost change outlined in earlier slides
- The only alternative to installing the scrubber is to NOT install the scrubber
  - *$457M for scrubber is not transferrable to other clean energy projects*
- Without the scrubber, Merrimack Station will be out of compliance with state and federal laws, which would lead to a shutdown of the plant
- PSNH customers could be on the hook for $300 million in stranded costs, with nothing to show for it
  - $230M for scrubber costs already committed
  - $63M for undepreciated cost of Merrimack Station in 2013

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What Is the Harm in a 90-Day Study?

- What a study will **NOT** do:
  - Change the cost of the scrubber
  - Change Merrimack Station's fuel source
  - Provide accurate forecasts for the price of oil, gas, coal, or financing rates
  - Tell you what federal regulations will be passed and when
  - Tell you how much renewable energy NH will build, where it will be located, and when it will be in service
  - Accurately predict the future
- What a study **will** do:
  - Invite lengthy speculation and create momentum to not install the scrubber
  - Set Merrimack Station on the path to a shutdown

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What Is the **Benefit** of a 90-Day Study?

- The study cannot change the price of the scrubber
- It cannot transfer the $457M scrubber cost to other energy projects
- If the study *supports* the scrubber installation, it is redundant and not needed
- The only logical purpose for performing a study is to create momentum to derail the scrubber installation

Voting in favor of SB 152 is voting to shut down Merrimack Station.

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The Bridge to NH's Clean Energy Future

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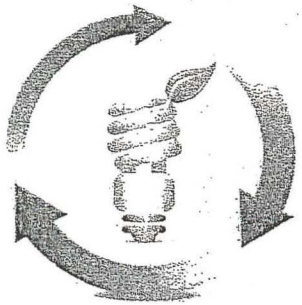
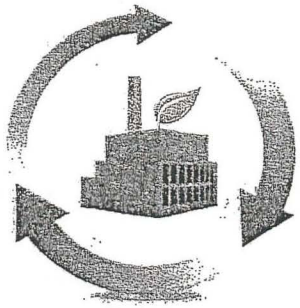
PSNH is Pursuing a Portfolio of Strategies to Advance Clean Energy in New Hampshire

Enhance and Expand Energy-Efficiency Programs



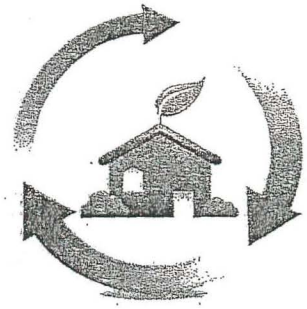
- Revise programs to meet modern needs
- Double investment in efficiency programs
- Goal of quadrupling energy savings for PSNH customers by 2025

Significantly Cut Emissions at Existing Power Plants



- Install scrubber at Merrimack Station
- Pilot alternative energy sources at PSNH facilities
- Increase efficiency at existing hydro plants

Invest in Renewable Energy Projects



- Small-scale projects (e.g. solar panels)
- Commercial-scale renewable power plants
- Import hydro power from Canada
- Provide transmission to connect customers with renewable energy sources

Data Request TC-03
Dated: 08/24/2012
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Conclusions

- **The Scrubber Project is NH's Bridge to a Renewable Energy Future**
- In the short-term, it is unrealistic to think that we can depend on new renewable energy sources in NH to replace the power produced by existing fossil fuel plants
- It is important to make our existing power plants cleaner and more efficient because they still provide most of our energy at the lowest cost
- Shutting down Merrimack Station would create needless economic harm to our state at a time when NH citizens are fighting every day to keep their jobs
- We implore you to vote NO to Senate Bill 152 -- *Voting in favor of SB 152 is voting to shut down Merrimack Station.*

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Clean Air Project

Merrimack Station

Merrimack Station Clean Air Project

- PowerAdvocate, Inc.
  - Premier provider of supply-chain and sourcing solutions to energy companies
  - Direct experience on over 20 different FGD projects with 9 different companies in the past 5 years
- Merrimack Station Cost Estimate
  - 19 benchmark wet FGD projects were compared to Merrimack Station
  - Owner's costs and site specific factors were analyzed to make it "apples to apples"
  - Benchmark projects were escalated to 2012 dollars (Merrimack Station's projected in-service date)
  - Merrimack per kW cost of $580 is within both the benchmark range ($272-$704/kW) and median cost ($517/kW) of the other wet FGD projects
- Project Sourcing Process and Contracting Terms
  - A procurement strategy and competitive bid process were used to ensure cost controls for customers
  - Performance guarantees and cost risks were transferred to the key suppliers to provide customer cost protection
- Cost Savings Opportunities Exist
  - Market volatility and dropping commodity prices provide near term savings opportunities
    - $6M (35%) foundation contract savings
  - Other savings opportunities exist

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Dated: 08/24/2012
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In Re:

DE 11-250 PUBLIC SERVICE COMPANY OF N.H.

INVESTIGATION OF SCRUBBER COSTS AND COST RECOVERY

DEPOSITION OF: GARY LONG

September 16, 2013

SUSAN J. ROBIDAS, N.H. LCR

(603) 622-0068 shortrptr@comcast.net

(603) 540-2083 (cell)

Original File 091613GaryLong.txt

Min-U-Script® with Word Index

THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 11-250

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Investigation of Merrimack Station Scrubber Costs and Cost Recovery

PREFILED TESTIMONY OF MICHAEL E. HACHEY ON BEHALF OF TRANSCANADA POWER MARKETING LTD. AND TRANSCANADA HYDRO NORTHEAST INC.

ATTACHMENT 25

Transcript of Deposition of Gary Long in this docket – September 16, 2013 – link:
http://www.puc.state.nh.us/Regulatory/Docketbk/2011/11-250.html
October 11, 2013 entry in docket

Merrimack Scrubber Costs - DOE/EIA Annual Energy Outlook 2008 Gas Forecast

Name Plate Capacity (MW)	459.2
Operating Capacity (MW)	432.5
Capacity Factor (%)	86%
Output @ 86% CF (MW)	372.0
Heat Rate (BTU/kWh)	10,126
Esacaltion	2.5%
Implied Market Heat Rate	7.62
Return on Equity	9.81%

BLUE FONT = INPUT

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Net Generation (MWh)	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Electric Market Price Development																	
Gas Price Used in PSNH Analysis	$ 8.63	$ 8.56	$ 8.50	$ 8.43	$ 8.68	$ 8.93	$ 9.17	$ 9.42	$ 9.67	$ 10.08	$ 10.50	$ 10.92	$ 11.33	$ 11.75	$ 12.40	$ 13.06	$ 13.71
NEPOOL Market Price Forecast (All hours)	$ 65.74	$ 65.24	$ 64.74	$ 64.24	$ 66.13	$ 68.01	$ 69.90	$ 71.79	$ 73.67	$ 76.84	$ 80.01	$ 83.18	$ 86.35	$ 89.52	$ 94.50	$ 99.48	$ 104.47
Energy Market Revenues	$ 214,202,845	$ 212,572,602	$ 210,942,360	$ 209,312,117	$ 215,458,682	$ 221,605,248	$ 227,751,813	$ 233,898,378	$ 240,044,944	$ 250,370,495	$ 260,696,046	$ 271,021,597	$ 281,347,148	$ 291,672,700	$ 307,911,130	$ 324,149,561	$ 340,387,992
Capacity Price ($/MW-mo)	$ 3,640	$ 3,690	$ 3,770	$ 3,870	$ 3,980	$ 4,080	$ 4,180	$ 4,410	$ 4,740	5070	$ 5,390	$ 5,720	$ 6,050	$ 6,370	$ 6,700	$ 7,030	$ 7,350
Capacity Market Revenues	$ 18,891,600	$ 19,151,100	$ 19,566,300	$ 20,085,300	$ 20,656,200	$ 21,175,200	$ 21,694,200	$ 22,887,900	$ 24,600,600	$ 26,313,300	$ 27,974,100	$ 29,686,800	$ 31,399,500	$ 33,060,300	$ 34,773,000	$ 36,485,700	$ 38,146,500
Total Energy Revenues	**$ 116,547,222**	**$ 231,723,702**	**$ 230,508,660**	**$ 229,397,417**	**$ 236,114,882**	**$ 242,780,448**	**$ 249,446,013**	**$ 256,786,278**	**$ 264,645,544**	**$ 276,683,795**	**$ 288,670,146**	**$ 300,708,397**	**$ 312,746,648**	**$ 324,733,000**	**$ 342,684,130**	**$ 360,635,261**	**$ 378,534,492**
SCRUBBER ONLY COSTS																	
Merrimack Go-Forward Cost Development																	
Scrubber Annual Carrying Charges																	
Pre-tax Capital Return	$ 23,952,745	$ 43,358,612	$ 37,831,702	$ 32,318,340	$ 26,824,168	$ 22,937,743	$ 20,681,405	$ 18,470,475	$ 16,290,203	$ 14,126,789	$ 11,963,412	$ 9,800,071	$ 7,636,767	$ 5,473,503	$ 3,310,277	$ 821,982	$ -
Depreciation	$ 15,240,702	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 15,240,702	$ -
O&M	$ 2,976,112	$ 5,936,638	$ 6,085,884	$ 6,238,886	$ 6,395,739	$ 6,556,539	$ 6,721,387	$ 6,890,384	$ 7,063,635	$ 7,241,246	$ 7,423,329	$ 7,609,995	$ 7,801,360	$ 7,997,543	$ 8,198,665	$ 8,404,851	$ -
Property Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel																	
Coal Consumption (BTU)	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000
Coal, With Scrubber ($/MMBtu)	$ 4.77	$ 4.89	$ 5.01	$ 5.14	$ 5.27	$ 5.40	$ 5.53	$ 5.67	$ 5.81	$ 5.96	$ 6.11	$ 6.26	$ 6.42	$ 6.58	$ 6.74	$ 6.91	$ 7.08
Total Fuel Cost	**$ 78,718,866**	**$ 161,373,675**	**$ 165,408,017**	**$ 169,543,218**	**$ 173,781,798**	**$ 178,126,343**	**$ 182,579,502**	**$ 187,143,989**	**$ 191,822,589**	**$ 196,618,154**	**$ 201,533,608**	**$ 206,571,948**	**$ 211,736,246**	**$ 217,029,653**	**$ 222,455,394**	**$ 228,016,779**	**$ 233,717,198**
Scrubber Only Revenue Requirement	**$ 120,888,425**	**$ 241,150,330**	**$ 239,807,008**	**$ 238,581,849**	**$ 237,483,110**	**$ 238,102,030**	**$ 240,463,699**	**$ 242,986,253**	**$ 245,657,832**	**$ 248,467,594**	**$ 251,401,754**	**$ 254,463,419**	**$ 257,655,778**	**$ 260,982,104**	**$ 264,445,741**	**$ 252,484,314**	**$ 233,717,198**
INCREMENTAL COSTS																	
Pre-tax Capital Return	$ 3,288,698	$ 6,752,821	$ 7,053,710	$ 7,282,378	$ 7,442,305	$ 7,533,490	$ 7,562,487	$ 7,533,287	$ 7,444,736	$ 7,295,482	$ 7,081,057	$ 9,352,385	$ 12,239,729	$ 13,224,969	$ 14,210,259	$ 7,590,858	$ -
Depreciation	$ 5,333,333	$ 5,933,333	$ 6,533,333	$ 7,133,333	$ 7,733,333	$ 8,333,333	$ 8,933,333	$ 9,533,333	$ 10,133,333	$ 10,733,333	$ 11,333,333	$ 11,933,333	$ 12,533,333	$ 13,133,333	$ 13,733,333	$ 14,333,333	$ 14,933,333
O&M	$ 411,844	$ 925,640	$ 1,135,602	$ 1,406,899	$ 1,773,281	$ 2,155,396	$ 2,455,895	$ 2,806,790	$ 3,225,824	$ 3,738,347	$ 4,390,646	$ 7,261,649	$ 12,498,711	$ 19,320,378	$ 35,192,287	$ 77,669,991	$ -
Property Tax	$ 1,865,412	$ 2,105,986	$ 2,394,498	$ 2,720,005	$ 3,259,004	$ 3,728,627	$ 3,965,610	$ 4,102,765	$ 3,986,050	$ 3,839,021	$ 3,667,557	$ 4,757,929	$ 6,125,494	$ 6,509,069	$ 6,876,353	$ 7,227,391	$ 7,304,608
Emissions Costs	$ 22,756,975	$ 2,639,868	$ 2,705,865	$ 16,715,659	$ 23,658,860	$ 27,594,552	$ 28,284,416	$ 28,991,526	$ 29,716,314	$ 30,459,222	$ 31,220,703	$ 32,001,220	$ 32,801,251	$ 33,621,282	$ 34,461,814	$ 35,323,359	$ 36,206,443
Incremental Revenue Requirement	**$ 33,656,262.0**	**$ 18,357,648.0**	**$ 19,823,008.0**	**$ 35,258,274.0**	**$ 43,866,783.0**	**$ 49,345,398.0**	**$ 51,201,741.0**	**$ 52,967,701.0**	**$ 54,506,257.0**	**$ 56,065,405.0**	**$ 57,693,296.0**	**$ 65,306,516.0**	**$ 76,198,518.0**	**$ 85,809,031.0**	**$ 104,474,046.0**	**$ 142,144,932.0**	**$ 58,444,384.0**
TOTAL REVENUE REQUIREMENT (Scrubber + Incremental)	**$ 154,544,687**	**$ 259,507,978**	**$ 259,630,016**	**$ 273,840,123**	**$ 281,349,893**	**$ 287,447,428**	**$ 291,665,440**	**$ 295,953,954**	**$ 300,164,089**	**$ 304,532,999**	**$ 309,095,050**	**$ 319,769,935**	**$ 333,854,296**	**$ 346,791,135**	**$ 368,919,787**	**$ 394,629,246**	**$ 292,161,582**
Energy Revenues less Rev. Req't	**$ (37,997,465)**	**$ (27,784,276)**	**$ (29,121,357)**	**$ (44,442,705)**	**$ (45,235,011)**	**$ (44,666,980)**	**$ (42,219,427)**	**$ (39,167,676)**	**$ (35,518,545)**	**$ (27,849,204)**	**$ (20,424,904)**	**$ (19,061,537)**	**$ (21,107,648)**	**$ (22,058,135)**	**$ (26,235,656)**	**$ (33,993,985)**	**$ 86,372,910**
/MWh	$ (11.66)	$ (8.53)	$ (8.94)	$ (13.64)	$ (13.88)	$ (13.71)	$ (12.96)	$ (12.02)	$ (10.90)	$ (8.55)	$ (6.27)	$ (5.85)	$ (6.48)	$ (6.77)	$ (8.05)	$ (10.43)	26.51
NPV (line 53 to year 2027)	($270,442,424)																

Merrimack Scrubber Costs - Synapse Energy Economics 2007 Final Report Gas Forecast

Name Plate Capacity (MW)	459.2
Operating Capacity (MW)	432.5
Capacity Factor (%)	86%
Output @ 86% CF (MW)	372.0
Heat Rate (BTU/kWh)	10,126
Escalation	2.5%
Implied Market Heat Rate	7.62
Return on Equity	9.81%

BLUE FONT = INPUT

Year		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Net Generation (MWh)		3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Electric Market Price Development																		
Gas Price Used in PSNH Analysis	$	8.97	$ 8.36	$ 8.65	$ 8.80	$ 9.22	$ 9.81	$ 9.94	$ 10.12	$ 10.56	$ 10.99	$ 11.67	$ 12.12	$ 12.58	$ 13.06	$ 13.55	$ 14.07	$ 14.61
NEPOOL Market Price Forecast (All hours)	$	68.35	$ 63.70	$ 65.91	$ 67.06	$ 70.26	$ 74.75	$ 75.74	$ 77.11	$ 80.47	$ 83.74	$ 88.93	$ 92.32	$ 95.84	$ 99.49	$ 103.29	$ 107.23	$ 111.32
Energy Market Revenues	$	222,708,136	$ 207,562,990	$ 214,763,141	$ 218,487,358	$ 228,915,164	$ 243,563,748	$ 246,791,402	$ 251,260,461	$ 262,184,829	$ 272,860,916	$ 289,744,030	$ 300,795,504	$ 312,268,505	$ 324,179,111	$ 336,544,014	$ 349,380,542	$ 362,706,683
Capacity Price ($/MW-mo)	$	3,640	$ 3,690	$ 3,770	$ 3,870	$ 3,980	$ 4,080	$ 4,180	$ 4,410	$ 4,740	5070	$ 5,390	$ 5,720	$ 6,050	$ 6,370	$ 6,700	$ 7,030	$ 7,350
Capacity Market Revenues	$	18,891,600	$ 19,151,100	$ 19,566,300	$ 20,085,300	$ 20,656,200	$ 21,175,200	$ 21,694,200	$ 22,887,900	$ 24,600,600	$ 26,313,300	$ 27,974,100	$ 29,686,800	$ 31,399,500	$ 33,060,300	$ 34,773,000	$ 36,485,700	$ 38,146,500
Total Energy Revenues	$	**120,799,868**	$ **226,714,090**	$ **234,329,441**	$ **238,572,658**	$ **249,571,364**	$ **264,738,948**	$ **268,485,602**	$ **274,148,361**	$ **286,785,429**	$ **299,174,216**	$ **317,718,130**	$ **330,482,304**	$ **343,668,005**	$ **357,239,411**	$ **371,317,014**	$ **385,866,242**	$ **400,853,183**
SCRUBBER ONLY COSTS																		
Merrimack Go-Forward Cost Development																		
Scrubber Annual Carrying Charges																		
Pre-tax Capital Return	$	23,952,745	$ 43,358,612	$ 37,831,702	$ 32,318,340	$ 26,824,168	$ 22,937,743	$ 20,681,405	$ 18,470,475	$ 16,290,203	$ 14,126,789	$ 11,963,412	$ 9,800,071	$ 7,636,767	$ 5,473,503	$ 3,310,277	$ 821,982	$ -
Depreciation	$	15,240,702	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 15,240,702	$ -
O&M	$	2,976,112	$ 5,936,638	$ 6,085,884	$ 6,238,886	$ 6,395,739	$ 6,556,539	$ 6,721,387	$ 6,890,384	$ 7,063,635	$ 7,241,246	$ 7,423,329	$ 7,609,995	$ 7,801,360	$ 7,997,543	$ 8,198,665	$ 8,404,851	$ -
Property Tax	$	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel																		
Coal Consumption (BTU)		32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000
Coal, With Scrubber ($/MMBtu)	$	4.77	$ 4.89	$ 5.01	$ 5.14	$ 5.27	$ 5.40	$ 5.53	$ 5.67	$ 5.81	$ 5.96	$ 6.11	$ 6.26	$ 6.42	$ 6.58	$ 6.74	$ 6.91	$ 7.08
Total Fuel Cost	$	78,718,866	$ 161,373,675	$ 165,408,017	$ 169,543,218	$ 173,781,798	$ 178,126,343	$ 182,579,502	$ 187,143,989	$ 191,822,589	$ 196,618,154	$ 201,533,608	$ 206,571,948	$ 211,736,246	$ 217,029,653	$ 222,455,394	$ 228,016,779	$ 233,717,198
Scrubber Only Revenue Requirement	$	120,888,425	$ 241,150,330	$ 239,807,008	$ 238,581,849	$ 237,483,110	$ 238,102,030	$ 240,463,699	$ 242,986,253	$ 245,657,832	$ 248,467,594	$ 251,401,754	$ 254,463,419	$ 257,655,778	$ 260,982,104	$ 264,445,741	$ 252,484,314	$ 233,717,198
INCREMENTAL COSTS																		
Pre-tax Capital Return	$	3,288,698	$ 6,752,821	$ 7,053,710	$ 7,282,378	$ 7,442,305	$ 7,533,490	$ 7,562,487	$ 7,533,287	$ 7,444,736	$ 7,295,482	$ 7,081,057	$ 9,352,385	$ 12,239,729	$ 18,224,969	$ 14,210,259	$ 7,590,858	$ -
Depreciation	$	5,333,333	$ 5,933,333	$ 6,533,333	$ 7,133,333	$ 7,733,333	$ 8,333,333	$ 8,933,333	$ 9,533,333	$ 10,133,333	$ 10,733,333	$ 11,333,333	$ 11,933,333	$ 12,533,333	$ 13,133,333	$ 13,733,333	$ 14,333,333	$ 14,933,333
O&M	$	411,844	$ 925,640	$ 1,135,602	$ 1,406,899	$ 1,773,281	$ 2,155,396	$ 2,455,895	$ 2,806,790	$ 3,225,824	$ 3,738,347	$ 4,390,646	$ 7,261,649	$ 12,498,711	$ 19,320,378	$ 35,192,287	$ 77,669,991	$ -
Property Tax	$	1,865,412	$ 2,105,986	$ 2,394,498	$ 2,720,005	$ 3,259,004	$ 3,728,627	$ 3,965,610	$ 4,102,765	$ 3,986,050	$ 3,839,021	$ 3,667,557	$ 4,757,929	$ 6,125,494	$ 6,509,069	$ 6,876,353	$ 7,227,391	$ 7,304,608
Emissions Costs	$	22,756,975	$ 2,639,868	$ 2,705,865	$ 16,715,659	$ 23,658,860	$ 27,594,552	$ 28,284,416	$ 28,991,526	$ 29,716,314	$ 30,459,222	$ 31,220,703	$ 32,001,220	$ 32,801,251	$ 33,621,282	$ 34,461,814	$ 35,323,359	$ 36,206,443
Incremental Revenue Requirement	$	33,656,262.0	$ 18,357,648.0	$ 19,823,008.0	$ 35,258,274.0	$ 43,866,783.0	$ 49,345,398.0	$ 51,201,741.0	$ 52,967,701.0	$ 54,506,257.0	$ 56,065,405.0	$ 57,693,296.0	$ 65,306,516.0	$ 76,198,518.0	$ 85,809,031.0	$ 104,474,046.0	$ 142,144,932.0	$ 58,444,384.0
TOTAL REVENUE REQUIREMENT (Scrubber + Incremental)	$	**154,544,687**	$ **259,507,978**	$ **259,630,016**	$ **273,840,123**	$ **281,349,893**	$ **287,447,428**	$ **291,665,440**	$ **295,953,954**	$ **300,164,089**	$ **304,532,999**	$ **309,095,050**	$ **319,769,935**	$ **333,854,296**	$ **346,791,135**	$ **368,919,787**	$ **394,629,246**	$ **292,161,582**
Energy Revenues less Rev. Req't	$	(33,744,819)	$ (32,793,889)	$ (25,300,575)	$ (35,267,465)	$ (31,778,530)	$ (22,708,480)	$ (23,179,838)	$ (21,805,593)	$ (13,378,660)	$ (5,358,783)	$ 8,623,081	$ 10,712,369	$ 9,813,708	$ 10,448,277	$ 2,397,228	$ (8,763,004)	$ 108,691,601
/MWh	$	(10.36)	$ (10.06)	$ (7.77)	$ (10.82)	$ (9.75)	$ (6.97)	$ (7.11)	$ (6.69)	$ (4.11)	$ (1.64)	$ 2.65	$ 3.29	$ 3.01	$ 3.21	$ 0.74	$ (2.69)	$ 33.36
NPV (line 53 to year 2027)		($153,443,683)																

Merrimack Scrubber Costs - Brattle Group Gas Forecast

Name Plate Capacity (MW)	459.2
Operating Capacity (MW)	432.5
Capacity Factor (%)	86%
Output @ 86% CF (MW)	372.0
Heat Rate (BTU/kWh)	10,126
Esacaltion	2.5%
Implied Market Heat Rate	7.62
Return on Equity	9.81%

BLUE FONT = INPUT

Year		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Net Generation (MWh)		3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282	3,258,282
Electric Market Price Development																		
Gas Price Used in PSNH Analysis	$	8.62	$ 8.45	$ 8.71	$ 8.83	$ 9.13	$ 9.69	$ 9.85	$ 10.03	$ 10.44	$ 10.54	$ 11.03	$ 11.53	$ 11.90	$ 12.22	$ 12.58	$ 13.06	$ 13.63
NEPOOL Market Price Forecast (All hours)	$	65.68	$ 64.42	$ 66.34	$ 67.26	$ 69.59	$ 73.86	$ 75.03	$ 76.44	$ 79.54	$ 80.31	$ 84.07	$ 87.84	$ 90.69	$ 93.09	$ 95.83	$ 99.50	$ 103.87
Energy Market Revenues	$	213,991,399	$ 209,890,968	$ 216,140,291	$ 219,147,231	$ 226,731,467	$ 240,672,831	$ 244,477,503	$ 249,077,805	$ 259,178,315	$ 261,687,369	$ 273,927,083	$ 286,198,087	$ 295,490,884	$ 303,316,415	$ 312,246,970	$ 324,197,150	$ 338,437,510
Capacity Price ($/MW-mo)	$	3,640	$ 3,690	$ 3,770	$ 3,870	$ 3,980	$ 4,080	$ 4,180	$ 4,410	$ 4,740	5070	$ 5,390	$ 5,720	$ 6,050	$ 6,370	$ 6,700	$ 7,030	$ 7,350
Capacity Market Revenues	$	18,891,600	$ 19,151,100	$ 19,566,300	$ 20,085,300	$ 20,656,200	$ 21,175,200	$ 21,694,200	$ 22,887,900	$ 24,600,600	$ 26,313,300	$ 27,974,100	$ 29,686,800	$ 31,399,500	$ 33,060,300	$ 34,773,000	$ 36,485,700	$ 38,146,500
Total Energy Revenues	$	116,441,500	$ 229,042,068	$ 235,706,591	$ 239,232,531	$ 247,387,667	$ 261,848,031	$ 266,171,703	$ 271,965,705	$ 283,778,915	$ 288,000,669	$ 301,901,183	$ 315,884,887	$ 326,890,384	$ 336,376,715	$ 347,019,970	$ 360,682,850	$ 376,584,010
SCRUBBER ONLY COSTS																		
Merrimack Go-Forward Cost Development																		
Scrubber Annual Carrying Charges																		
Pre-tax Capital Return	$	23,952,745	$ 43,358,612	$ 37,831,702	$ 32,318,340	$ 26,824,168	$ 22,937,743	$ 20,681,405	$ 18,470,475	$ 16,290,203	$ 14,126,789	$ 11,963,412	$ 9,800,071	$ 7,636,767	$ 5,473,503	$ 3,310,277	$ 821,982	$ -
Depreciation	$	15,240,702	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 30,481,405	$ 15,240,702	$ -
O&M	$	2,976,112	$ 5,936,638	$ 6,085,884	$ 6,238,886	$ 6,395,739	$ 6,556,539	$ 6,721,387	$ 6,890,384	$ 7,063,635	$ 7,241,246	$ 7,423,329	$ 7,609,995	$ 7,801,360	$ 7,997,543	$ 8,198,665	$ 8,404,851	$ -
Property Tax	$	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel																		
Coal Consumption (BTU)		32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000	32,993,363,532,000
Coal, With Scrubber ($/MMBtu)	$	4.77	$ 4.89	$ 5.01	$ 5.14	$ 5.27	$ 5.40	$ 5.53	$ 5.67	$ 5.81	$ 5.96	$ 6.11	$ 6.26	$ 6.42	$ 6.58	$ 6.74	$ 6.91	$ 7.08
Total Fuel Cost	$	76,718,866	$ 161,373,675	$ 165,408,017	$ 169,543,218	$ 173,781,798	$ 178,126,343	$ 182,579,502	$ 187,143,989	$ 191,822,589	$ 196,618,154	$ 201,533,608	$ 206,571,948	$ 211,736,246	$ 217,029,653	$ 222,455,394	$ 228,016,779	$ 233,717,198
Scrubber Only Revenue Requirement	$	120,888,425	$ 241,150,330	$ 239,807,008	$ 238,581,849	$ 237,483,110	$ 238,102,030	$ 240,463,699	$ 242,986,253	$ 245,657,832	$ 248,467,594	$ 251,401,754	$ 254,463,419	$ 257,655,778	$ 260,982,104	$ 264,445,741	$ 252,484,314	$ 233,717,198
INCREMENTAL COSTS																		
Pre-tax Capital Return	$	3,288,698	$ 6,752,821	$ 7,053,710	$ 7,282,378	$ 7,442,305	$ 7,533,490	$ 7,562,487	$ 7,533,287	$ 7,444,736	$ 7,295,482	$ 7,081,057	$ 9,352,385	$ 12,239,729	$ 13,224,969	$ 14,210,259	$ 7,590,858	$ -
Depreciation	$	5,333,333	$ 5,933,333	$ 6,533,333	$ 7,133,333	$ 7,733,333	$ 8,333,333	$ 8,933,333	$ 9,533,333	$ 10,133,333	$ 10,733,333	$ 11,333,333	$ 11,933,333	$ 12,533,333	$ 13,133,333	$ 13,733,333	$ 14,333,333	$ 14,933,333
O&M	$	411,844	$ 925,640	$ 1,135,602	$ 1,406,899	$ 1,773,281	$ 2,155,396	$ 2,455,895	$ 2,806,790	$ 3,225,824	$ 3,738,347	$ 4,390,646	$ 7,261,649	$ 12,498,711	$ 19,320,378	$ 35,192,287	$ 77,669,991	$ -
Property Tax	$	1,865,412	$ 2,105,986	$ 2,394,498	$ 2,720,005	$ 3,259,004	$ 3,728,627	$ 3,965,610	$ 4,102,765	$ 3,986,050	$ 3,839,021	$ 3,667,557	$ 4,757,929	$ 6,125,494	$ 6,509,069	$ 6,876,353	$ 7,227,391	$ 7,304,608
Emissions Costs	$	22,756,975	$ 2,639,868	$ 2,705,865	$ 16,715,659	$ 23,658,860	$ 27,594,552	$ 28,284,416	$ 28,991,526	$ 29,716,314	$ 30,459,222	$ 31,220,703	$ 32,001,220	$ 32,801,251	$ 33,621,282	$ 34,461,814	$ 35,323,359	$ 36,206,443
Incremental Revenue Requirement	$	33,656,262.0	$ 18,357,648.0	$ 19,823,008.0	$ 35,258,274.0	$ 43,866,783.0	$ 49,345,398.0	$ 51,201,741.0	$ 52,967,701.0	$ 54,506,257.0	$ 56,065,405.0	$ 57,693,296.0	$ 65,306,516.0	$ 76,198,518.0	$ 85,809,031.0	$ 104,474,046.0	$ 142,144,932.0	$ 58,444,384.0
TOTAL REVENUE REQUIREMENT (Scrubber + Incremental)	$	154,544,687	$ 259,507,978	$ 259,630,016	$ 273,840,123	$ 281,349,893	$ 287,447,428	$ 291,665,440	$ 295,953,954	$ 300,164,089	$ 304,532,999	$ 309,095,050	$ 319,769,935	$ 333,854,296	$ 346,791,135	$ 368,919,787	$ 394,629,246	$ 292,161,582
Energy Revenues less Rev. Req't	$	(38,103,187)	$ (30,465,911)	$ (23,923,426)	$ (34,607,591)	$ (33,962,226)	$ (25,599,398)	$ (25,493,737)	$ (23,988,249)	$ (16,385,174)	$ (16,532,330)	$ (7,193,867)	$ (3,885,048)	$ (6,963,912)	$ (10,414,420)	$ (21,899,817)	$ (33,946,396)	$ 84,422,428
/MWh	$	(11.69)	$ (9.35)	$ (7.34)	$ (10.62)	$ (10.42)	$ (7.86)	$ (7.82)	$ (7.36)	$ (5.03)	$ (5.07)	$ (2.21)	$ (1.19)	$ (2.14)	$ (3.20)	$ (6.72)	$ (10.42)	$ 25.91
NPV (line 53 to year 2027)		($197,518,305)																

Date: March 13, 2009
Time: 9:00 a.m.
Room: Reps Hall

The Senate Committee on Energy, Environment and Economic Development held a hearing on the following:

SB 152	relative to an investigation by the public utilities commission to determine whether the scrubber installation at the Merrimack Station is in the public interest of retail customers.

Members of Committee present:	Senator Fuller Clark Senator Merrill Senator Lasky Senator Cilley Senator Odell

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The Chair, Senator Martha Fuller Clark, opened the hearing on SB 152 and invited the prime sponsor, Senator Janeway, to introduce the legislation.

Senator Harold Janeway, D. 7: I won't begin in 1960, 49 years ago, when the first unit began operations. Rather I'll focus on the legislative history that is relevant to what we're talking about here today.

It begins in 2002 with House Bill 284, which was known as the New Hampshire Clean Power Act. Gary Long was there for that, and has been in attendance at all subsequent issues related to this.

Representative Jeb Bradley presented his bill to this same Committee, one member of which now sits with distinction on the Public Utilities Commission. In Bradley's testimony, he discussed trading pollution credits, energy efficiency initiatives and mercury. And here's what he said.

He said: "...and lastly you will hear discussion that we're not doing enough on mercury control." This was back in 2002. "Mercury is a serious pollutant, it is a potent neurotoxin, has significant adverse health effects, particularly for women of childbearing age and for prospective babies."

Testimony in the House indicated that the likely emissions from these plants range from 30 lbs. of mercury emitted to as much as 330, and it was our DES that estimated the higher number. In an EPA website, the lower number. It is rational, therefore, to do what this bill proposes to do: test PS New Hampshire's facilities for the actual amount of mercury, wait for the EPA regulations on mercury, which are expected to occur in the next several years, and then devise a strategy that would have to come back to this Legislature at some point in time for enactment in the future.

"That," he said "is a rational response, especially in light of what you folks and those of us in the House have done, which is fight for lower mercury levels from the waste to energy facilities."

So, the issue did come back to the Legislature four years later, and it appeared in the form of House Bill 1673, which had subsumed a Senate bill, it was Senate Bill 128, with a similar thrust. And that was the bill that gave Public Service of New Hampshire its marching orders in June 2006.

I want to just quote from the summary of that particular meeting, when Senator Odell brought the bill to the floor on the Senate. He said: "This bill provides for an 80 percent reduction of mercury emissions from coal burning power plants by requiring the installation of scrubber technology no later than July 1, 2013, and provides economic incentives for earlier installation and greater reductions in emissions." Incidentally, Senate Research has compiled a full history of those two bills. It's a rather substantial packet, but certainly you'll want to have that available to you as a reference as you work your way along.

Clearly, the most frequently asked question that I get, in various forms, is essentially "why stir the pot? The company is moving ahead as directed." "Get over it," some of them add. And so I want to try to respond to that question this morning.

First of all, the projected cost has, as I think everyone knows, risen sharply, about 80 percent. I personally don't feel that that's the most important issue, and it's one that I suspect will be answered fairly fully today, but it was one that certainly got everyone's attention. An extra $200 million plus is a sizeable sum. But I think more important, at least to me, is the fact that there have been major changes in the fundamentals that do bear on this issue since that particular action was taken. And so I would ask, in response to the question of "why stir the pot," I would ask, would you invest today based on what you knew two and a half years ago or what you know now? And to me the answer is, I would want to take into consideration those things that

are known now before making my decision. So I'm essentially firmly in the camp of those who believe that we should be open to new information.

So then the question is, what is new and what is relevant? My answer, I will try to keep it brief, but is fairly detailed. First of all, the industry is undergoing much change, and more in recent years than probably in multiple decades prior, to when it was a fairly simple business and was all regulated. Oversimplified, back in the perhaps good old days, the more power you sold, the more plants you could build, the larger the investment base on which you could earn a return. This was the "live better electrically"era. Then came deregulation and things got messy. But none of that is particularly new.

But there are new things that have developed over the past two and a half years that we really do need to think about. First of all, the environmental pressures have ramped up considerably. Even with the Bush Administration's denial of many environmental issues and climate change, these things have built up during the past few years and it is clear with this change in administration that we now have, we now face considerably more regulation and more pressure to act. Coal plants, the best of them, still emit substantial pollutants of various sorts, as you well know. They're a major source and are going to come under special pressure.

Another issue that's become substantially more of a factor than it was in past years is this whole question of energy independence. Where do we get our energy from? And that brings in the drive towards renewables. As many of you know, we have a goal of 25 percent renewables here in New Hampshire by 2025. We're a fair ways from that now, but that's something that clearly is going to be a factor, and coal definitely is not a renewable. The carbon dioxide, which has been a major force and continues to be a major force in climate change, is going to come under pressure. I think there's, most people would agree, there's a high likelihood that we will see a cap and trade program from, which attempts to deal with that issue. The evidence for climate change, unfortunately, continues to grow.

Efficiency is something that has become more evident over the past few years. Efficiency measures are now paying off, and we're actually seeing a change in the long term growth curve in the demand for electricity as a result of that. But the whole efficiency thing is really just beginning to break through. The potential savings in commercial buildings, in homes, and these aren't efficiencies that mean turning off your heat or turning off your lights, it's just investing in efficiency measures that are going to make a substantial difference and are going to bend the growth curve as we look out into the future.

So the slowdown in demand for electricity that we've seen over the past year or more, while it's been exaggerated by the slowdown in the economy, has more to it than that. Texas Utilities for instance, one of the major utilities in the country, I think reported a six percent decline in sales last year, closing a number of plants. This is something that's going on industry-wide. So we have to think about the effects of efficiencies. The Obama Administration, as I've mentioned, is now pushing incentives for greater sustainability and connected to that, I would say, is the prospect for a substantial number of jobs. Many of the programs that we've seen in the stimulus program that will come to New Hampshire will bring some money to areas where there can be a lot of good jobs and a lot of substantial benefit.

Another thing that we have to factor in is the likelihood of high, increasing standards, higher thresholds for mercury, among other things, that will face us in the period ahead. So I think it's important when we look at this issue that we keep that in mind. I don't see this as really two paths that diverge, one good, one bad. We're still, it's still really one path, but I think the path that we're moving along is moving through a landscape that has changed dramatically.

So the question is, do we adapt and adjust to that changing landscape or do we essentially go ahead without consideration to what's happening all around us? And that is essentially what needs to be studied. I know that it's hard to swallow, even for the short term, because it's a major project and it's been a long time in building and it's underway. But I feel very strongly that what we're seeking here, which is a study, a relatively short study, is necessary. And I think that that's the least that we can do for the ratepayers. I'm reminded of an old musical which was called "The King and I," which was about the king of Siam and he had a governess he brought in to raise his kids. And the governess taught him that most of his views were totally out of line with reality and eventually he was brought around to her way of thinking, and there was a song in that where the refrain was, "I think I want to think it through again." So all I'm asking is that you give us a chance to think this through again. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you very much, Senator Janeway. Are there questions from the Committee? Senator Odell.

Senator Harold Janeway, D. 7: Good morning.

Senator Bob Odell, D. 8: I appreciated very much the history of the background on this legislation, because I think that's very important, about where we've come from. And I was going to ask that question had you not

raised that. But I also want to add a couple of statements and then ask for a response.

And that is that in 2006, the vote on the Senate floor was 22-2 to go forward with the scrubber, and let me put it in the simplest of terms. There was a different party in charge at that time, the Republicans were in the majority. I chaired this Committee, for example. We became convinced, that is some of us, that the public health danger to children and young women of childbearing age was so compelling that we needed to take action right then. Two hundred and fifty million dollars to me sounded like a huge amount of money, huge amount of money. But I think of the child that is born today or a mother about to conceive in Manchester or in some other community east of here, and I say if that child's public health interest, the prevention of cancer, was to be $1.00, I would be for it. But for each of those children, if the price was $2.00, I would still be for it. This to me is a public health issue. We fought very, very hard to get consensus within both parties to pass this bill. We understood there would be new technology, new advances, but we didn't want to do exactly what's happening in this room today, consider putting it off one more time, over and over again.

And it's come me not as a debate about public health, but when a lobbyist or the advocates of your bill drive to Lempster, New Hampshire and sit down and say we represent commercial ratepayers. And I say, who ratepayers? Well, 28 ratepayers, commercial ratepayers. And I say okay, I represent 55,000 people here who are worried about jobs, they're worried about public health, they're worried about cancer, they're worried about pollution. And I just have the greatest trouble of going back and looking at what we went through in 2006, which I think was one of the high points of my time in the State Senate, passed this bill, and then come today, have somebody say, oh, but you might have not known enough to go forward.

I know something about young people and children who suffer with cancer. We had a presentation yesterday morning about CHAD. We saw two children with cancer. If I were to be here today and not do everything I can to get this scrubber up, inadequate as it may be, I think I would have failed the mission we adopted as a policy of this State of New Hampshire in 2006. I just come to you today and I would say, Senator, would you consider letting us go ahead with the scrubber, meanwhile, go ahead with the study on the side. Three months, six months, whatever it is. I'd rather have you do a good study, but let's get on to the scrubber from the standpoint of public health, nothing else. Two hundred fifty million, five hundred million dollars, children, women who could be pregnant, cancer, I just can't turn back.

Senator Harold Janeway, D. 7: That's a good statement and I can't disagree. There's nothing in this bill that actually says stop. It says please study. And I agree about mercury. I think, when I think about dealing with this mercury and you think about trying to remove whatever, 80 percent of 140 lbs. out of, I'm not sure of the arithmetic, I think it's a billion pounds of coal, I don't see how it works, but it does take some major action to do it. So, as I say, please, the bill does not require a halt.

Senator Martha Fuller Clark, D. 24: Follow up?

Senator Bob Odell, D. 8: That's fine.

Senator Martha Fuller Clark, D. 24: Are there additional questions from members of the Committee? Thank you very much, Senator Janeway.

Senator Harold Janeway, D. 7: Thank you, Senator Clark.

Senator Martha Fuller Clark, D. 24: I'd now like to call upon Senator Gatsas.

Senator Theodore L. Gatsas, D. 16: Thank you, Madam Chairman, members of the Committee. I'm Senator Ted Gatsas, I represent the towns of Dunbarton, Bow, Hooksett, Candia and Wards 1, 2 and 12 in Manchester. I'm here to speak against both the bill and the amendment. I think the Committee needs to consider some things. You have an amendment before you that says, and we've heard that possibly they could report out in 90 days. There was different testimony that came out in the House hearing a few days ago. At the end of 90 days when you get that report, what do we plan on doing? Calling a special session to close the project? Being here in the same position we are today? We have a project that's going at full force. By October, it's going to be well into the project. So what are we attempting to do at that time?

And Senator Odell, I'd like to, because history is very important. And I think that we need to talk about the history of this bill from the beginning, because in the Senate, House, Senate Bill 128 was before the Senate and I was on Energy, on that committee, and Senator Johnson was the Chairman. We listened to testimony and we saw sheets that were passed out of the red zones in the State of New Hampshire. Those red zones were very apparent in Raymond-Exeter. They were absolutely fire red. I think it's important that we all understand that this is a health issue. This was about taking mercury out of the air, not anything else.

There was an amendment that came out of that committee on Senate Bill 128, and what it said was that the total mercury emissions from all affected sources, burning coal as a fuel, of 50 lbs. per year beginning July 2008. So the amendment that came out of that Senate committee forced Public Service to remove mercury by 2008. Well, that got everybody's attention and it got it pretty quick, because the acceleration that we had in that bill was that all mercury would have been removed by 2011. So that's the true history of the bill, and that's what got the sides together at a table. An environmentalist coming in and saying, that's a great amendment, we're thrilled to death by it.

I think another important issue is that when you talk about history, that there is a committee report on Senate Bill 128. And there were a lot of questions asked and a lot of discussions. I think the most important one, though, is that when you go back, and I'm going to quote, the Conservation Law Foundation came in and they were discussing the legislation. And here's the question:

Senator Gatsas: Thank you, Mr. Chairman. And I quote: "Do you know that a dollar increase is a 15 percent increase on rates? Do you believe that the ratepayers should absorb all of that?"

That was my question to Ms. Gerard.

"Well, right now the law says they would. But I believe the ratepayers have absorbed it in the past and probably should. I will say this, though, after Representative Hennessy's remarks."

So at the time when we heard that it might be a dollar and there was not one question about a $275 million cost. That was an awful lot of money back in 2005, and nobody raised the question about cost.

So the amendment and the legislation do one thing – kind of look, turn back the history of time and look at Seabrook. Delays there cost an awful lot of money to ratepayers throughout the State of New Hampshire. There is more cost and less study of RGGI. We passed a piece of legislation last year called RGGI. There was less study. This bill, when it came through the Senate about removing mercury, took two years to look at. The cost to the ratepayers in the State of New Hampshire with the cost of RGGI is going to be more than what the scrubber costs us. The difference is, that in the RGGI costs there's no CO^2 that's coming out of the air, there's no technology that takes CO^2 out of the air. There is technology to take mercury out of the air and save lives.

I know that people may be a little confused of why I'm standing here and supporting Public Service and their efforts to move forward. I think Gary Long and I have had our discussions in the past about what ratepayers should be paying and what they shouldn't be paying. But there is a time to talk about prudency and that's when the project is done and costs are in. And maybe at that time I say, well wait, the ratepayers shouldn't be paying for all of this, the stockholders should be paying for some of it. But none of us should take a position today to stop the project, until that project is completed and we have an understanding of what the cost is. Because then maybe Gary Long and I will have a difference of opinion. We've done it in the past, but now I stand with him and say that that project needs to be completed because for every home in the Town of Bow, if that project is closed and Public Service closes Merrimack Station, for every home that's assessed $300,000 in the Town of Bow, it's an increase of $800 a year in taxes.

Let's not forget the railroad that delivers the coal. My bet is, that's a primary source of income and they may not be going up that railroad much longer.

So we don't need the PUC to look at it. They've looked at it. As a matter of fact, they probably might take 84 sessions like they did with energy efficiency to come out and tell us how to spend the money. It's probably going to take 84 sessions for them to study what to do with the RGGI money. So, we don't need delays. We don't need the closing of the Merrimack Station. We need this project to move forward. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you, Senator Gatsas. Are there questions from the Committee for Senator Gatsas? Seeing none, I'd like to call upon Senator Letourneau.

Senator Robert J. Letourneau, D. 19: Good morning.

Senator Martha Fuller Clark, D. 24: Good morning.

Senator Robert J. Letourneau, D. 19: Good morning, members of the Committee. Senator Odell, I remember very well serving on that committee when you were Chair, and I remember the bill passing and the discussion that took place. Today is a whole different discussion.

Madam Chairman and members of the Committee, for the record, I'm Bob Letourneau and I represent District 19, the towns of Derry, Hampstead and Windham. I believe this legislation poses a great risk to the residents of my district at a time we can least afford it. As you may know, the electric market reliability, ability has been a concern of mine throughout my tenure in the Legislature. That said, I have admired the way the Legislature,

regardless of political party or ideology, has been able to move New Hampshire forward on energy issues without creating undue risk for our state. While other states have rushed forward with untested policies or ideas, they have many times resulted in drastic results and costs. We have remained steady, determined and cautious in our movement forward.

I believe Senate Bill 152 will take New Hampshire down a new and risky path, where the foundation of our energy infrastructure is left exposed and unstable in a way to force our state in a new and untested and unreliable direction. While the stated purpose of this bill seems harmless, in reality it would create a scenario that will create greater costs for New Hampshire ratepayers, less energy security for our state as a whole, and the elimination of several hundred jobs. I supported creation of renewable energy because I want to see New Hampshire and the United States more reliant on domestic energy sources.

However, as leaders of New Hampshire we need to be honest about the challenges and hurdles that confront the development of renewable energy in our state. Many of the same challenges that confront fossil fuel generation also confront biomass, wind, hydro, solar. Some of the same interests here today opposed to the installation of environmental upgrades at the Merrimack Station are also opposed to the construction of a wind farm in northern New Hampshire. Political, environmental and financial, geographical hurdles all stand in the way of renewable energy.

I have brought along several copies of a column in the Wall Street Journal last week on the development of renewable energy in this country, and you have it there in my testimony. And while there were many issues raised in this piece, the one thing that struck me was the statement that we are tearing down more hydroelectric generation than we are building. Two years ago, this committee had considerable debate over a bill that I brought forward to allow a regulated utility to build one renewable energy project in the North Country. At the time, we were told that a tremendous progress, an opportunity that was happening in that part of that state, and that we should not allow a regulated utility to upset the great progress of the merchant developers - Tamarax' Groveton biomass project, Noble's wind farm, clean energy development, Berlin's biomass project and Laidlaw's Berlin biomass project. There are a variety of reasons why these projects have either died or moved at a very slow pace. But the bottom line is, we have not seen the boom in renewable energy that was predicted four years ago or even two years ago. While the ISO New England lineup may be filled with projects, how many of these projects will actually get built? One in 25? One in 15? Generally, the odds are not that good.

I also want to talk just a little bit about cost. For anyone who deals with construction, the idea that costs have escalated tremendously over the past two years should not be a big surprise. In my capacity as Chair of the Transportation Committee, the issue of construction costs has driven our policy development for the past two years. For example, in 2006 a ton of liquid asphalt cost $250. Last summer, that cost had risen to approximately $850 a ton. Cost increase for steel, concrete, gravel and labor are all well known. In the light of these cost increases, the bipartisan approach that we have taken is to make sure that the foundation of our transportation infrastructure is maintained and secure. I would suggest to you making sure that our state's primary base load power plants remain stable, secure and viable. It is the best way that we can protect our energy infrastructure during these difficult times, as well as position our state for economic growth into the future.

We should also view the cost of the environmental upgrades at Merrimack Station in the light of other energy projects that are happening in New Hampshire. Consider that we are talking about spending $450 million to ensure a 440 watt, megawatt base plant that runs 24/7, remains secure, viable and reduces its environmental impact. In the North Country, developers are talking about spending $250 million on an intermittent wind project that will produce one-tenth the electrical output of the Merrimack Station. Increases in construction costs are impacting all aspects of construction, even renewable power development. Again, I am in support of renewable energy, and I want to work towards a renewable future in New Hampshire. But those of us in the Legislature need to be realistic about where we are today, the cost of achieving a cleaner future and the hurdles that stand in our way. And I'm sure you will hear from countless experts today what our energy future holds. And I can tell you from my expert opinion, and that was gained from unfortunately from age, is that nobody knows what the future will hold. We don't know what the costs will be, what regulations will be enacted, what new technologies will be developed and I don't know where we will be next year, needless to say, that we will be in 10 years , or where we'll be in 10 years. When it comes to energy, all we can do is try to expose our constituents to as little risk as possible as we progress forward. And we can do that by defeating Senate Bill 152.

Last, but most importantly, we have recently learned that this bill would jeopardize up to 1,200 jobs in New Hampshire, as evidenced by the hearing here today. Considering the economy and almost seven percent unemployment rate, this is exactly the wrong bill at a time when New Hampshire is facing the highest unemployment rate in 15 years, and I respectfully urge the Committee to find Senate Bill 152 inexpedient to legislate. Thank you.

Please see Attachment #1, Senator Robert Letourneau's testimony.

Senator Martha Fuller Clark, D. 24: Thank you, Senator Letourneau. Are there questions from the Committee for Senator Letourneau? Seeing none, I'd like to call upon Representative Pat Long.

Representative Pat Long: Thank you, Madam Chair, honorable Senators. First, I'd like to publicly thank Public Service Company of New Hampshire. Not for jobs, not for good jobs, but for family sustaining jobs, family sustaining wages, family dignified healthcare in pride and independence with engineers. Not to mention the trainings that are involved with the agreement that they have made with the contractors.

I'm not going to reiterate what has already been said. However, I do have concerns when I read, when I read of reasonable anticipated environmental compliance costs. Reasonable is a tough word. When I read of the investigation shall be completed as expeditiously as possible but give the report within 90 days.

My expertise here today is not on, is not on the energy, energy field. My expertise is on jobs. And I'm not sure if you could put yourself in a position where, for six or seven months, you've been collecting unemployment and then in these tax times, you're looking at paying your taxes on this unemployment. Obviously, you're looking at families that are taking three to four weeks of that unemployment pay to pay their taxes on. By no means, I want you to think that my main focus is on jobs and jobs alone.

However, in this economy, on March 13, 2009, when I have an opportunity, when I have an opportunity to, when I have a choice that I have to make or my constituents have to make, with several of them are here, whether they want to plant a tree or whether they want a job, today I would say that they would like a job. That doesn't demise, that doesn't diminish them as to wanting clean air. The fact is, the reality is, their desperation is for work in these times, and with that I'll let you know that I'm opposed to this Senate bill and I'm sure that you'll do your due diligence in listening to the testimony and execing this bill out as ITL. I thank you very much for your time.

Senator Martha Fuller Clark, D. 24: Thank you very much, Representative Long. Are there questions for the Representative? Seeing none, I'd like to call upon Representative Chris Hamm.

Representative Christine Hamm: Thank you, Madam Chair, and members of the Committee. For the record, I am Christine Hamm and I represent Merrimack District 4, the towns of Hopkinton, Warner and Webster. And I'm here today to ask for your support for Senate Bill 152, which was drafted in an attempt to adhere to the conditions established three years ago with the passage of HB 1673. That bill's slate of sponsors ran the gamut from those with pragmatic business interests to visionary environmentalists, and was hailed at its passage as a bipartisan effort towards reducing mercury emissions in the State of New Hampshire. As a House member, I voted for HB 1673 because I thought it was a necessary step forward. It had required negotiation and compromise. It promised to reduce mercury emissions throughout the state, most significantly at Merrimack Station in Bow, the largest single source of mercury emissions in this state.

Today, three years later, I come to you because I believe that the expectations we had for this bill have changed and that we're now in a different place. In the text of HB 1673, part V, the bill notes that the installation of scrubber technology will not only reduce mercury emissions significantly, but will do so with reasonable costs to consumers. Although the phrase "reasonable costs to consumers" may sound amorphous, for those involved, including the members, some of the members of this Committee, it did in fact have a specific number attached to it. We know this from a letter, which I can provide to the Committee, from Michael P. Nolan, then the Commissioner of the Department of Environmental Sciences, to Senator Bob Odell, then the Chairman of this Committee. That letter, dated April 11, 2006, states: "Based on data shared by PSNH, the total capital cost for this full redesign will not exceed $250,000,000 in 2013 dollars, or $197,000,000 in 2005 dollars, a cost that will be fully mitigated by the savings in SO^2 emission allowances. Commissioner Nolan sent this same letter to Representative Larry Ross, who was the Chairman of the House Committee on Energy, on Science, Technology and Energy, and that letter was dated January 12, 2006.

Today, when the $197,000,000 2005 figure has already jumped to $457,000,000 in 2009 dollars, it's clear that the original expectation of $250,000,000 in 2013 dollars is beyond reach. $250,000,000 is a big number, and so is $457,000,000. It's a little taxing for us mere mortals to comprehend it. So it seems useful to try to put these numbers in context. As members of this Committee know too well, New Hampshire's shortfall for the biennium was recently projected to be $500 million. Yet, as legislators have contemplated what to do about that, taxing our citizens to make up this difference has never seemed a viable option. Why then wouldn't we at least take the time to hesitate before holding our state ratepayers, these same citizens, accountable for a similar sum? Again, to put $457 million in context, this legislator, Legislature has heard from a group of private

investors to say they would be willing to invest $450 million into Rockingham Park, making that project the second largest capital investment ever made in this state. Seabrook was the largest. Yet, $450 million is still $7 million shy of the $457 million projected to install filters at Bow to mitigate only part of the emissions from Merrimack Station.

Additionally troubling is the fact that as these costs have risen, the Legislature has remained in the dark. An annual report, filed by Chairwoman Naida Kaen of the House Science and Technology Committee on behalf of the Electric Utility Restructuring Legislative Oversight Committee, notes that at the Committee's June 18, 2008 meeting, "There was no cost information provided to indicate a significant departure from the projections made in 2006." Again, I can provide this to you. PSNH reported the project costs would be updated with a review of major equipment bids. Despite the cost increase announced six weeks later on August 1, 2008, this report filed on November 1st of that year does not contain the update.

Further, it is important that this committee consider that there has been no review of this cost increase by any state agency. PSNH says that the Public Utilities Commission will review the cost in an after the fact prudency review. But how prudent is that? Why not now instead of later, when it will be too late, too expensive to change course? With no cap on costs, we have to wonder, at what point do we reach our limit? How much is too much to spend to rejigger a 40 year old coal plant at the end of its life span? Is nearly half a billion dollars the best use of anybody's money to produce 430 megawatts of electricity?

In September of last year, similar questions were brought to the PUC, but it concluded it did not have the authority to determine whether the scrubber project is in the public interest, finding that the Legislature had already made that decision by passing HB 1673. This legislation is being put forward to enable the PUC to go forward with that analysis. As I said earlier, HB 1673 was a major step forward for its time. But now the decision this Committee makes on whether or not PSNH should go on with installing scrubbers that currently cost 83 percent more than anticipated and whose final cost is yet to be determined, will be key to whether that step forward proceeds down the right path.

We live in New Hampshire, famous for Robert Frost's crossroads in the woods. I believe New Hampshire is now at an energy crossroads, at a new place in our understanding of the importance of our energy sources. Since 2006, not only the cost but also technologies have changed, and so have the political realities in the regulatory landscape. We now understand that there are other less expensive alternatives, such as activated carbon

injection, that could address these emissions less expensively. We also understand that we must address other emissions, including CO^2 emissions. It appears likely that the new administration plans to have a carbon program in place by 2012. In addition, the EPA will likely introduce new mercury rules, which could mean that the emissions reduction provided by this new scrubber will not adequately comply with EPA standards. As we've heard in testimony on a related bill in the House, that would mean additional controls and additional costs for ratepayers.

To go back to HB 1673, I draw your attention to part VI, which notes that the installation of such technology is in the public interests of the citizens of New Hampshire and the customers of the affected sources. Again, I believe that when this was passed, that public interest was served. But now that the balance between cost and results has been skewed and it is clear that additional improvements will have to be made at additional cost, we have to wonder whether or not going forward with the installation remains in the public interest, and that is what we want the PUC to review.

As the bill states, as legislators our first concern should be the citizens of New Hampshire and PSNH's customers. I believe this Legislature, but first this Committee, needs to consider whether the agreement forged in HB 1673 is still in the best interests of New Hampshire's citizens and PSNH's ratepayers. The sponsors of this bill are not alone in thinking it is not. Currently there are more than a dozen pending dockets, cases and permits relating to Merrimack Station, ranging from a Title V permit under the Federal Clean Air Act; to a case before the New Hampshire Supreme Court filed by the commercial ratepayers group; to guidance memorandum from the EPA requiring PSNH to apply maximum achievable control technology retroactively to 2005, something that the scrubbers as currently configured do not achieve; to another case filed jointly by the Conservation Law Foundation and Freedom Energy, questioning the legality of the new turbine which increased the output of the plant and was installed without DES permits in April 2008; to a PUC order requiring a study and economic analysis of retirement for any unit in which the alternative is the investment of significant funds to meet new emissions standards and/or enhance or maintain plant performance; to the Obama Administration's announcement of a new federal CO^2 program; to a pending report from the Governor's Climate Change Task Force.

Clearly, in the three years since HB 1673 was passed, the ground has shifted and clearly there are many important questions to be answered. Clearly our constituents, the PSNH ratepayers, deserve the same kind of cost benefit analysis for an expenditure of this magnitude that PSNH would undertake for its shareholders. Four years from now, or 15 years from now, as energy

rates rise into the stratosphere, we simply cannot tell our constituents that although we knew of these coming federal changes, the pending issues with the plant and the 83 percent cost increase that has not yet been reviewed, we did not review our options before going forward. No one is talking about doing nothing. Clearly, it is our job to make certain that the ratepayers of this state are protected, at the same time ensuring that our energy sources have the smallest possible environmental impact.

I urge this Committee to take these responsibilities seriously. Recently, representatives from PSNH reminded us that New Hampshire led the nation by passing the Clean Power Act in 2001. Let's not see that tradition, one that all of us have the right to be proud of, go up in smoke. Thank you very much.

Senator Martha Fuller Clark, D. 24: Thank you very much, Representative Hamm. Are there questions from the Committee? Senator Lasky.

Representative Hamm: Good morning.

Senator Bette R. Lasky, D. 13: We have before us an amendment which replaces the bill, and I forgot to ask Senator Janeway about it. But I wondered if you could point out the significant differences in the amendment, as we were just given it this morning?

Representative Hamm: You should ask Senator Janeway rather than me. Okay. I was involved a little bit at the beginning of this and then he, I have read the amendment as he's shown it to me, but I'm not the one to really talk about the differences.

Senator Bette R. Lasky, D. 13: Thank you.

Senator Martha Fuller Clark, D. 24: Senator Janeway, would you be able to answer that?

Senator Harold Janeway, D. 7: I can't, without the prior bill, give you precise. There were changes that were designed to make sure that the PUC wasn't forced into the longer, sort of more formal process, and other than that, really the thrust of it remains the same. I'll see if I can get for you. Actually there were a series of modest tinkers that were made as we moved along. I'll try to get a full set so you can see how that went, if that's alright.

Senator Martha Fuller Clark, D. 24: I guess I'm elected. Senator Lasky, does that answer your question?

Senator Bette R. Lasky, D. 13: Certainly. Thank you, Senator Janeway.

Senator Martha Fuller Clark, D. 24: Senator Janeway, I do have a question for you, which was raised by Senator Gatsas. Is once, if this bill were to go forward, once this study was finalized, how do you believe that it would be useful to the Legislature and to all of the citizens of New Hampshire and our constituents?

Senator Harold Janeway, D. 7: Well, my first answer to that is that I think we all need more information and so that shining a light on the issue would be helpful to everybody, whether it goes forward or not. So I think there is, if you will, an educational process that would be part of the outcome here. I can't predict exactly what follow-up measures would take place. It may be something that would come forward in the subsequent sessions, but I don't see how there would be anything immediate or dramatic.

Senator Martha Fuller Clark, D. 24: Follow-up. I know that one of the concerns of many of the people here today are that this bill is a thinly veiled attempt to close down the scrubber. Would you be able to speak to that? And what, I guess that's my question to you.

Senator Harold Janeway, D. 7: I certainly don't see it that way and that wasn't the intent. We're looking for more insight, more information, more perspective. I think there, I'm pretty sure there are people who support this bill who would like to see that happen. I'm not one of them. The sponsors aren't in that position, so it's somewhat, I'm inclined to say, a way of trying to trash it when that is not the intent.

Senator Martha Fuller Clark, D. 24: Thank you. Additional questions?

Senator Bob Odell, D. 8: Thank you, Madam Chair. Representative Hamm (INAUDIBLE), I think Representative, Representative Hamm mentioned this issue of prudent cost. When does this, if this is a, I'm trying to get from a very simple example, the 90 day process, if I'm understanding...

Senator Harold Janeway, D. 7: Correct.

Senator Bob Odell, D. 8: ...but as you go through this prudent cost aspect of this, how do you, what happens if you say it's a little imprudent or not a little imprudent? Where are we at that point, and I do go back to Senator Gatsas as a follow-up to the Chair, so then what do we do when September, October, November of this year, with whatever we have as far as information? How does that ennoble (sic) this body, the Legislature, to do something?

Senator Harold Janeway, D. 7: Well, I think it's so much, we're all having trouble, it's not so much focused on the costs of the scrubber project, it's going to be what it's going to be. It's more, what does the commitment to that scrubber imply in terms of future costs if other measures that I referred to as possible, say the EPA decides that the mercury limit should be 90 percent or 95 percent instead of 80 percent? Or if water temperatures require, and other such things, require additional investments? So it's looking beyond the, the hope is that the study will look at the possibilities beyond the scrubber that would lead to substantially higher costs. And you'll hear testimony on that, I think, from others today.

Senator Bob Odell, D. 8: In a practical way, what I've heard from some today is quite speculative about what EPA will do, what this organization is going to do, what the standards are going to be due (sic), what the changes are going to be due (sic). Let's say we go 90 days and we have this study parallel to activity at the site, and then something changes on the 93rd day after the study is going on. And this seems to me as if it's always a moving target, there's going to be dramatic changes as we go forward. I think no one's learned quicker than President Obama that things don't happen on his schedule. There's Congress and there's a lot of other factors at play here, but somebody has picked an arbitrary 90 day period, if I'm correct, to assess this, and I just don't know how you put a deadline on a $500 million project and say okay, at, in 90 days we're going to be able to tell you that here's some plausible, I think that's the term here, plausible situations that might evolve in the future. And I don't know how far out the future is? Is that one year, two years, twenty-five years? And I guess that's the question.

Senator Harold Janeway, D. 7: Yeah.

Senator Bob Odell, D. 8: How does this really fit in with the reality of a $450 million project?

Senator Harold Janeway, D. 7: Well, I agree nothing is certain in this life or in this world. But our concern is that there hasn't been any attempt at this point to look at those other potential things, and the EPA, for instance, has already made some, taken some action that points to, you know, stricter standards. There are, it's far less likely that, most of, a number of them relate to new coal plants rather than existing coal plants, but there are, the direction in which the EPA is moving is pretty clear. And 90 days just seemed like enough time to assess what we know now, as opposed to, and look at that, compared to what was known when your bill, which I fully supported from the outside back in '06, did. So it's an update, let's just look at this and be sure we've thought it through.

Senator Martha Fuller Clark, D. 24: Senator Lasky. Thank you.

Senator Bette R. Lasky, D. 13: Thank you, Madam Chair. Senator Janeway, as I see in the amendment and as I've seen all along in looking at this project, is one of the major questions I believe that's still out there, is the projected costs of supplying customers with purchases in the wholesale power market. And that is one of the things that you want to analyze. Do you have any projected figures as to what that might be now, as opposed to, you know, going ahead with the scrubber?

Senator Harold Janeway, D. 7: Thank you for the question. There are current costs in the purchase power market which others will be able to speak to. They've come down quite substantially with, in line with the surplus of capacity that has developed. ISO New England, which is the outfit that collects all the data on New England's power pool, has estimated that there are, there is the equivalent of perhaps seven Merrimack Stations surplus capacity right now. And even future, projected out, I think three years or so, so that has pushed down the price, but others who you will hear from later can provide more detail on that.

Senator Bette R. Lasky, D. 13: Thank you, I will ask them. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you. Other questions? Let us move forward. Representative Walz.

Representative Mary Beth Walz: Thank you, Madam Chair.

Senator Martha Fuller Clark, D. 24: INAUDIBLE

Representative Walz: I will not, although I do intend to answer some of the inaccurate information that my predecessor had stated. So to that end, I would like to thank the Committee. I am Representative Mary Beth Walz. I represent Merrimack County District 13, which includes the towns of Bow and Dunbarton, so the plant is in my district.

And with that, I might add that this is a plant I've been familiar with since well before I was elected to the Legislature. I probably had my first tour of the plant about 15 or 16 years ago, and over time I have followed that plant and come to understand a lot about it, including how the darn thing runs. And so I'm more than a little familiar with the plant and how it fits into PSNH's plan for power in New England. So I do not come at this as green as perhaps some of my fellow representatives.

Well, I'd like to start off and say that I am quite alarmed by the fact that we have this bill before us at all. I find this incredibly disingenuous of the environmentalists to be bringing this bill forward at this time. I, too, remember, as was testified before, that three years ago this bill was touted as a huge success, because we brought the environmentalists, we brought the company and we brought the Legislature to the table and we all came to an agreement. We all looked at all those factors and came to this agreement that allowed the company to move forward at what was going to be great expense to them, but it also cleaned up the air of mercury. This plant's going to take 85 percent of the mercury out of the air. It's twice as good as any carbon injection system, that has been referenced earlier. I know Representative Hamm suggested carbon injection. This reduces twice the mercury any carbon injection system can. The company worked with EPA on carbon injection systems and this is the best way to get mercury out of the air. So this was a great plan that moved this forward after carbon injection systems, and said this is the way that we can get the most mercury out of the air.

So, then I looked at this bill, and this bill, the original bill said what is in the best interests of the retail customers? So I looked at the bill initially in that respect, and we know that we need reliable, economical base load power in this state. And I heard testimony up here from Senator Janeway before, that we have an excess of power in this state. I sat there stunned! Stunned! Does he understand this winter how close we came to not meeting our load need? There are jet engines at the Merrimack power plant. I didn't know this until recently. There are jet engines that have been there since the 1960s, and when the plant itself, and when all the plants that are fired up in New England can't meet the base load, they turn those jet engines on, and somehow beyond my knowledge, they can generate electricity using those jet engines. This winter, they were running those jet engines! We didn't have enough power on some of those cold mornings to meet the power needs of New England. They had to turn the jet engines on! Where does (inaudible (1:01:20) we've got seven times the load of Merrimack excess in New England comes is well beyond me, because the experience of this very winter contradicts that.

One thing that the proponents of this bill keep talking about is that we need renewables, and they talk about wind and they talk about solar. What we need here is base load power. You need power that you can call up when you need it and have constantly running. Renewable power, like wind and solar, is intermittent power. You can't just call on it, you're the victim of the weather. Does the wind blow, does the sun shine? And what happens at night? When you replace the Merrimack Station, which we are going to have to do, you're going to have to replace it with some sort of long term viable

base load power, not intermittent power. And that difference seems to have been lost on the people talking about this bill. But it's an important distinction. You can't replace base load power with intermittent power.

They also talk about the economy here. We all have heard endlessly about, because of the increased cost here, about how this needs to be looked at. The reality is, as I stand here today, PSNH has the cheapest utility rates of any utility in all of New England, the cheapest rates, not just in New Hampshire – in all of New England. If you take and you put that scrubber on at $250 million, they're still the cheapest power. If you take it and you put it on at $450 million, maybe we're not the cheapest anymore, but we are still below market. And the power coming out of the Bow power plant is still below market. So if you shut down that plant and you try and replace that power at market rate, my understanding is it's going cost you, today, $30 million a year to replace it at market rates. That's more than it would cost just to pull that power out of the plant with the scrubbers.

Now, I can stand here and do that as a back of the envelope computation. You don't need a 90 day study from the PUC to run that simple calculation. So I would suggest that you need to be looking at that factor as well.

Now if, it's not clear me that this study calls for delay. But if there is a delay due to this study, if you take a three month delay, because of the work season here, because of our winters, a three month delay means a nine to twelve month delay in the construction on that plant. What does a nine to twelve month delay do? Well, for one thing, we get all that extra time of mercury spewing in the air. I am troubled and confused with how the environmentalists think it's a good thing to keep the mercury spewing in the air while we slow down doing this.

Secondly, it increases the cost even more. So they're coming at you and are screaming about the cost of this plant, but what they're proposing is going to increase the cost even more. Why would we want to take a course of action that's going to make the scrubber even more expensive than what the market costs have made it already?

Now, what will the study show? I know you asked Senator Harold Janeway that. That was a really mushy answer, from my point of view. What are they going to do with that information? Even if you have the study, what do you do with the information? You got two choices: either you go forward or you shut down the plant. Shutting down the plant doesn't seem like a viable alternative. We've got, I think, about $200 or $250 million already invested in the scrubber which PSNH, under current law, would be allowed to recover. And I think if you didn't allow them to recover, it would be unconstitutional.

So we're already into this for a couple hundred million dollars. So we're going to stop? We're not going to, we're going to let them recover the $200 million because you have to, and then do what? Then start all over with a new plant that's likely to cost in excess of $500 million? I mean, I don't understand where we're going to go with this information.

We hear things have been changed. I have not heard from any of the proponents any new technology here. What has changed? In a short period of time, what has changed? There is no major earth shattering thing going on. We don't hear changes going on around the country. We don't hear power plants across the country changing what they're doing and putting in some newfound technology. This is the state of the art technology. So the costs have gone up. That happens. It happens on all kinds of things, you know. We'll deal with it and that's what the prudence review is there for.

Businesses need business certainty. Who are we as the Legislature to come in there and say, well, two years ago we thought this was a great idea so we passed this bill and we told you, PSNH, you have to do this and now you've spent a couple hundred million dollars on it. But, now we've changed our mind. What businesses want to stay here, when we've got a legislature like this that two years later is coming back and changing the rules of the game? You can't come back and do that to businesses. That is hardly a business friendly approach to anything in this state.

So I also looked at the amendment on this, which I saw a few minutes ago sitting down here. I had not seen it until somebody referenced it. I didn't even know there was an amendment. I've only had a moment to review the amendment, but if I look at the amendment, what you're doing is putting in a pre-instruction (sic) prudence review. So basically you're telling the Commission ahead of time what they have to do in this prudence review and you're telling the company ahead of time what you have to do, kind of regardless of the realities and regardless of the cost. I don't know how you can do that, and I don't know that that's a good approach to policy, particularly when we have a prudence review in state. Representative Hamm referenced that the prudence review comes too late to do anything. That's malarkey! The prudence review is there to make sure that the company's been honest in what they do, and if they're not honest, then the prudence review, under the prudence review the PUC has an obligation to disallow inappropriate costs. It's not discretionary, it's an obligation, and if they don't disallow it, you can bet the Consumer Advocate's going to take them to court and fight them for not disallowing inappropriate costs. So the prudence review that's in place now is more than adequate to deal with the increased costs of this plant.

So let's look at the situation. I maintain it's in the best interests of New Hampshire to go forward with this scrubber in a timely fashion. It's the most environmentally friendly approach, okay. We stop the mercury. We are, it's the least harmful to the ratepayers. In the long run, it's going to get power at the cheapest rate and it's going to get the mercury out of the air at the cheapest rate. And consistent with the first bill, I pulled the state energy policy that it references, and I've got to tell you, it's a home run. It's consistent with the state energy policy. I looked at this and I was frankly confused why the proponents bothered putting it in the bill, because this scrubber's so clearly consistent with the state energy policy.

So I would suggest that we as a legislator (sic) have an obligation here to approve this scrubber, then to look at ways we're going to meet our renewable goals that we have to do. We're going to look at fixing the transmission system in the North Country and coming down from the North Country, so they can put plants in. We're going to look at ways to put renewables out there. We're going to develop other forms of generation. But we can't do that now and still meet the power needs of the state. So let's put the scrubber in place, meet the power needs of the state, and use that time that the scrubber buys us in extending the safe life of the plant, to do what we need to do to put reliable, safe, environmentally friendly power in state and the transmission to carry that power to our ratepayers. Thank you.

Senator Martha Fuller Clark, D. 24: Are there questions for the Representative? Seeing none, INAUDIBLE

Representative Walz: Thank you.

Senator Martha Fuller Clark, D. 24: INAUDIBLE Are there any other representatives who want INAUDIBLE

Representative Frank Kotowski: Thank you, Senator Clark, Chairman, esteemed members of this panel. I stand here for the first time on this floor as a Representative, scared to death. My name is Frank Kotowski, District 9 in Hooksett. I stand here scared to death only for having to stand before this mike for the first time in 19 years. I worked for Public Service Company for 33 years of my life. I've not been through the front doors of Public Service Company for the last 18 years to speak with anyone who works there. I want you to know that. I rise here because I saw during my career with Public Service Company exactly what happens when perhaps well meaning people try to impress upon all of us the minority view. I believe that this project is terribly important to the future of the folks who live in my town who work at the Bow power plant, and I believe that I would be wrong if I didn't stand here and tell you that.

We all know what happened several years ago, at a time when Renny Cushing and myself and others debated these very issues. We took a project then that would have given New Hampshire true energy independence. That was the Seabrook project, I'm not afraid to say it. The company at the time had projected, if you recall, the cost of that plant to be $998 million for two, 1150 megawatt power plants, base load plants, such as the previous speaker spoke about the need for. And they delayed through these very same kinds of tactics that are being used right now on this bill. They delayed that project to a point where it brought a very good utility to its knees, bankrupted that utility, caused it to cancel one half of the project. Which ultimately, by the way, Florida Light and Power eventually, after having acquired it from Northeast Utilities, who bailed this good company out. I submit to you that you're going to really look carefully at this clearly but thinly veiled attempt to delay this project so that the costs continue to rise, for whatever purposes they have in mind.

Thank you very much.

Please see Attachment #2, Representative Frank Kotowski's testimony.

Senator Martha Fuller Clark, D. 24: Thank you very much. Are there questions for the Representative? Seeing none, are there any other representatives who would like to speak? Seeing none, I would like to call Gary Long.

Mr. Gary Long: Thank you, Madam Chairman, for the opportunity to speak. Thank you, Senators, for the opportunity to speak with you today. I'm Gary Long, I'm the President of Public Service Company of New Hampshire. After I give my remarks, there is another gentleman here named Gary Fortier, who's the Chief Operating Officer of a company called Power Advocates, and he is an expert in scrubber costs and he can show you how these scrubber costs fit in with the rest of the industry, and I hope put your mind to rest on this matter of scrubber costs, and I think he can show you how reasonable they are. And I'll have more to say about that also.

Now, I've been in this business for 33 years. I have spent a considerable amount of time and thought on this, and all the issues that we face. My career started about the time of the Arab oil embargo. I don't know if any of you remember those days and the disruption that that created for our society. Since that time, I've seen fuel prices go up, I've seen fuel prices go down. I've seen oil and gas prices go up and down and they all have gone on a steady upward trend. I've seen the rise and fall of nuclear power in this area.

There still are nuclear power plants, but there's far less now than there was 10 or 15 years ago. I've seen the emergence of energy efficiency as a way of doing business. I've seen a multitude of policies come out of both state and federal government, radical and very different policies in all those times. And I've seen forecast after forecast of what the future yields, what those policies might be, what those fuel costs might be, what the future price of power might be. And I can tell you every one of them's wrong.

So when you're dealing in a situation like that, and certainly we've all experienced that just recently, I will tell you that people did not project, experts that you pay money to, did not project that oil prices would go up to $145 a barrel. But when it was there, experts were telling us that it will be $200 a barrel. Three months later, it was $40 a barrel. Now, I'm not blaming anybody for that because nobody can really forecast the future. If they did, we wouldn't be in a recession. If they did, our 401(k) and our investment, our retirement programs wouldn't have lost 30, 40, 50 percent. We would have taken different actions if we had that perfect picture of the future. Yet when I hear someone say let's do a study, let's spend a million dollars, let's spend two million dollars. And wherever you stand on the study, I can guarantee you, whatever version of the future that that study tells you, you're got to be really careful about believing it and acting on it.

So what do you do in a situation where the rules are changing? What do you do in a situation where the energy costs are changing and policies are changing? As I said, I've lived that for 33 years, and there are ways to deal with it and we're dealing with it very effectively. There's some principles that we follow that have worked and been time proven. One is, you own assets. When you own physical assets, then you control your own fate, and you're not subject to the ups and downs and vagaries of the market. And one of the greatest decisions that this Legislature did was to say, PSNH you should keep your existing assets and generation. That has been hundreds of millions of dollars of value to our customers.

Another thing that people like me do, to ensure that customers are protected, is you have fuel diversity. We're learned time and time again, you cannot depend on one fuel source. As I say, the recent history has certainly showed what would happen if you relied on one fuel source. So the way you address that is to have fuel diversity. In fact, it's a state policy. In fact, it's a regional policy that we should have fuel diversity. PSNH has the most fuel diverse power supply mix in all of New England. We have more renewable power, percentage wise, than any other company in New England. It's not enough. We have coal, we have oil, we have gas, we have hydroelectric power, we have wood power. We buy a small amount of power from Vermont Yankee, there's a little bit of nuclear power. And recently we added to our

portfolio wind power, from the Lempster, the first wind park, energy park in New Hampshire, and we were part of that and helped make that happen.

So when people talk about Merrimack Station, we currently get very interested in that, and I should have started out by telling you we're strongly opposed to Senate Bill 152, in case you didn't know. Strongly opposed and we're asking every senator to vote against it. It is not a simple, it is not a simple study bill. It is a bill that is designed and geared for closing down Merrimack Station.

Now Merrimack Station provides fuel security, fuel diversity to our mix, it is our most economic power plant, and we have embarked on a multi-year plan to make it one of the cleanest coal plants in the nation. Not only does it do that for us and for our customers from an energy perspective, it also provides huge economic benefit to our state and to our community. You'll hear today about what its impact is on rail service. We are the anchor of rail between Concord, Manchester and Nashua, for those of you who are interested in commuter rail. We're one of those. You need Merrimack Station to help provide the platform for that, and you'll hear more about that today.

So we are, we are obviously strongly opposed and I just want to get into some of the things that are affected. When we look at this bill, and it's been said by others, but you either have a scrubber or you don't. The bill uses the word alternative. The alternative to having the scrubber is not having the scrubber. I don't think there's anybody in this room today who would say, I advocate running that power plant in the future without a scrubber, including Public Service Company. We're way beyond that. We're committed to putting the scrubber in that power plant and that's what everybody wants and that's what we want.

So the alternative to putting the scrubber in is <u>not</u> putting the scrubber in. And if you don't have a scrubber, you don't have a power plant. And that's why we feel so strongly that is really a bill about closing the plant, and Senator Janeway admitted that, although he himself does not claim to want to shut the power plant. He admits that supporters of this bill want to shut the power plant. So I think you need to look at it in those contexts and that's why you should vote against it.

As I said, Merrimack Station provides an incredible economic benefit and a foundation for rail and other things in this state, but more importantly, it provides hundreds of jobs. It provides hundreds of jobs for our own employees. It provides hundreds of indirect jobs for services that are provided to the plant. And right now it's going to provide hundreds of new construction jobs. As one of the reports said, this is not a shovel ready

project, this is a shovel in the ground project. Employment can start immediately. We have the permits, we're ready to go.

You have a package in front of you, and I'm going to be referring to some of those pages. I won't talk long on each one of them, but just so you can look at later. .But one of the things I want to address in the course of talking to you today is some of the myths that have been spread recently in this regard. One of the thoughts that you hear up there is that, gee, if we don't spend money on the scrubber, we have money to spend somewhere else. That's a total myth. We can spend money on a scrubber and we can spend money on energy efficiency, and we can spend money on renewables - we the state, we PSNH. They're not mutually exclusive. It's not an either/or. So I'd really like to put to rest in your mind the idea that if you say no scrubber, that somehow that frees up money. It doesn't. We're capable as a company to do all those things. They're not mutually exclusive.

Transcriber's note: Due to the volume of materials submitted by Public Service of New Hampshire, those documents are not attached to this transcript, but are available in the original bill file.

Another myth that's out there, is this is an old plant. Now if this was a car, I would agree with you, it's an old plant. It's an old car. But it's not an old plant, it's much newer than you think and I'll show you. I'll show you today in areas that it is new, far newer. And when you talk about infrastructure, old has a different kind of meaning than if you talk about a consumable good. You hear people alleging that these costs, the costs are going up. That $457 million, the costs are going to go up. I'll explain to you today something about construction projects and construction management. Hopefully we'll put that to rest, too. The costs aren't going to go up. If anything, the costs will go down, and it's the way that we execute projects like this is to avoid the costs from going up. And we can talk about that some more, too. So you can think about the 457 as a very good number. If anything, we're already taken steps to make it lower, barring a delay or something else that would add to the costs.

You also hear people on the myth that, gee, for some reason, we're not, won't be able to comply with federal regulations. Well first of all, they don't know what those federal regulations are, and secondly, they can't predict them anymore than anybody else, because we don't decide what those are and no individual decides that. So at best it would be speculative. But the way I look at this is putting a scrubber in and all the other things that we've done over the last 15 years, puts us well ahead of the rest of the nation. As the President of the company, I am so confident that we can comply with any federal law on carbon or mercury and that this project is the right time and

the right place to do that. I am not concerned in the least about changes in federal law. In fact, I welcome them. I hope that there is federal law, because I think there needs to be national policy on things like carbon. There needs to be national policy on things like mercury emissions. It just happens that New Hampshire is well ahead, well ahead of all that, and I compliment the Legislature and environmental groups in the state, regulators, all who worked to make this happen. For me as the President of the company, that puts us in a very good position, that I don't have to worry about federal regulations like some other utilities were, because we're already well ahead of the curve. So I think that's a myth or scare tactic that you should dismiss.

The other one that I think people didn't realize it or understand it, say well, the project hasn't started yet. I can tell you this project is almost in its fourth year. The project started the day you passed the law that said it was in the public interest. The project started the day you said, you ordered this, you put in the law, put in the scrubber. It started then and like all major construction projects, this is about a six year project. We're about the third year, we're almost in the fourth year of this six year project. The project started a long time ago. What you haven't seen is major construction, and we're right on the edge of starting that. But the project has started, and as mentioned by others, you have to start it, and you have to do your contracting to make things very solid and predictable, and we've done all that. And as you may have seen, we already have contractual commitments where we've spent up to $230 million and there'll be more as the project moves forward.

On page three, I'll do this very quickly, but I think most people understand that Bow operates 24/7. As one of the representatives mentioned, it's a base load plant. It's very reliable. It's running better now than it did when it was first built.

On slide four, you'll see some of the history of the plant. And like I say, some people call it an old plant. Actually, it's a plant that's run better and set records, set its all time plant operating records in the last four years. If it's an old plant, I'd say it's running better than it's ever run, and it's producing more efficient and economic power than it ever has in its history. So to me, that's not a definition of old, that's a definition of well run. If you were in the control room of our power plant, you would see an array of computers and computer screens. And these are things that didn't exist in 1960. They are not old.

Page six here really gets to the policy that you have set out over the last ten years or so, and we're actually very proud of the collaborative efforts that have gone on with the State over this period of time. We've had a history of

environmental groups, the company, regulators, legislators, working together and we're very proud of being very progressive in that area, as the state and as the company, and that's why we're so bothered by this bill, which does just the opposite. Instead of collaborating, this is putting people apart.

But if you look at page five, you'll see what we've done, as the state and as the company. We've had major, major improvements in environmental qualities of that plant. It's all because, it started in 2002, others have mentioned this, something called the Clean Power Act. Now we embarked on a path to take care of poor emissions. There's nox, tox, mercury and CO^2. And no one else in the country has ever done this. But we were willing to do it with you, and you were willing to do it with us. And the last two that needed to be addressed were mercury and CO^2. In 2006, through a long collaborative process where we all came together, very substantial votes, majority, large majority, sometimes unanimous votes out of committee, for this mercury bill - supported by the Governor, supported by the Legislature, supported by environmental groups, supported by the business community, supported by PSNH. That's the bill we're talking about today, that's the thing that brought us up today. And so we accomplished what we set out to do.

Back then, you asked PSNH, "Are you willing to put in a scrubber?" And after having that collaboration, we said "Yes, we are." And we do what we say we will do. We keep our word. You looked at us and said yes, as a state we want you to do this. How do you make sure that you do this, PSNH? And we said, well, our word is good, we will do this. You said, no, we're going to write a law and we're going to tell you to do it. And we said, fine, because we're going to do it. So you wrote a law and told us to do it in law. Then the next question is, we really would like to spend sooner, not later. Yes, we'll do it sooner, we'll do it the best we can, we'll execute this as fast as we can and do this as soon as we can. Well, how do we make sure that you do that? Well, you can always put a provision in law, and you did that. You wrote a provision in law that said that PSNH, if you put the scrubber in sooner than the absolute deadline which has been 2012, then you will create a financial benefit to your customers. Not to your investors. You will create a financial benefit to your customers.

Well, we've been working very diligently to do this as soon as possible, to do what you've asked us to do, which is to do it as soon as possible. So we do what we say we're going to do, and we have done what we said we're going to do, and we have done what you asked us to do. And what I'm asking you is to keep your word. What I'm asking you is to abide by the law that you created.

One page six here, there's another depiction of the accomplishments that we've collected, that we've done together and you will see, this is another reason why it's not an old plant. Since the plant was first installed, we've reduced particulate matter by over 95 percent. We've reduced nitric oxide by 85 percent. And with the scrubber, we've going to reduce mercury by 80, 85 percent, and we're going to reduce sulfur oxides by 90 percent. I think that's something we should all be cheering about and being proud about, and we should all be working to get this project done as soon as possible. That's what we should be doing. That's what PSNH is doing.

What's the status of the project? And as I mentioned earlier, it's on slide 7, if you're following along. I have no concerns about federal regulations, in fact, I welcome them. And that's one of the points of this slide.

One page 8, is a picture, a diagram of Merrimack Station. It gives you an idea of the footprint of that plant and how much has been added to it, and for, have environmental improvement, and what the scrubber will do as far as the footprint. And of course you'll see it's a rather large and substantial physical structure. And of course to do that, you need people, which will create a lot of jobs, a lot of good work. A lot of quality good work, and we're very pleased with the relationships we have with the unions that will help bring that good work to bear on this. And it couldn't be at a better time, in my opinion, in history. Not that we planned this. Of course, nobody wants a recession, but if we're in a recession like this, what better way to get people employed than to have an environmental project that makes a plant cleaner. So we're very, very proud of that, and we'd certainly like your support in getting that done.

Page nine, and again you know, I could talk to you at length about how one manages construction projects, but I know as legislators you may not have experience in that. But this really gets to the point that this project is not just started, it's been going on since 2006, and this is a typical way that you manage major projects, and you can see we've started. We already have, we did the preliminary engineering, we got a project manager, a program manager, who helps bring it all about. We've done the detailed engineering and we've issued major contracts last year, and we're ready to go on the major construction. We've done site preparation already. If you had, as Representative Walz said, she's been to the site many times. If she'd been to it recently, she'd see it looks much different than it was a year ago, because we've done a lot a site preparation in preparation for the permitting and major construction.

This may be a good time to give you an example of how projects are run. We're very, very proud of our wood burning power plant over on the seacoast.

And that, like the scrubber, is a result of your action, as a result of a law that was created in New Hampshire. As soon as you get a finding of public interest, which you have already done, you've given a finding of public interests in this in 2006. We got a finding of public interest on our wood project, I think it was 2004. But until you've got that finding of public interests, you're doing estimates, you're doing rough estimates, and the world changes. And during that period of time, 2004, '05, '06, prices also were going up during that time, and we had the same interests then that we have now, which is to contract in a way that you minimize and you stop and you lock in the prices so that they won't go up. And so we did that. As soon as we got the finding from the Commissioner of public interests, we issued the same sort of contract that we had with the scrubber, which are fixed price contracts. That means they can't go up. And so that project was a $75 million project, and we never, ever exceeded that $75 million throughout the whole construction cycle. In fact, we came in a little bit lower.

That's the same way that we're managing this scrubber project. We issued contracts. We're looking at $457 million, and now, and we're not going to exceed that. And so now we're looking at ways to bring it down, because we have fixed price contracts for all of our major contracts. They've already been issued. And that's the way you run projects and we've been very successful in that, and that's the way we protect customers. That's the way we make sure that customers are protected against escalation. That's why I say it's a myth for people to say the costs are going to be a lot more than that. They're not. If anything, they'll be less.

One page 11, it's a very important one. As I said, nobody can predict the future, but we are, and that's why we define things. And we know what the costs of the scrubber are going to be. We know that. You don't need a study for that, you don't need anyone to project the future. We know that cost, at least we know the maximum. And we know what the impact on rates are, and that's on page 11. You've heard it before. It's about three-tenths of a cent per kilowatt hour. And of course, you have to pay more if you've installed equipment like that. And it's going to cost more to have a cleaner power plant. But we all accept that. We all accepted that in 2006. We all knew that it costs money to have a cleaner power plant, and we're all willing to do that. But it's very competitive, and the plant will continue to be very competitive. You can see on that chart, that I don't want to trivialize point three cents a kilowatt hour, but it's well, well within the variations that you get in fuel costs, and it's well within the market value, the market differential between our plant and the market. So we feel quite comfortable, even though it is a price increase, the plant will continue to be highly competitive in the marketplace. And it gives us certainty.

Page 12, for those of you who are interested in more detailed cost estimates or prices and what a project is all about, there's nine or ten or so different elements of this project that all are contracted for separately and all that add up. So, you know, it's far more than putting in a flue gas, you know, de-sulfurization, there's a whole lot of other supporting and other work that goes with it. So just to give you a little idea.

We have very detailed documents on this. I mean the Public Utilities Commission can and will see all of this stuff. They look at all these project things and they do prudence review and they do a very thorough job. So we're not at all concerned with that, because we think we're doing a great job and we know they will do a very thorough job in reviewing what we did. But we don't have any problem with that. That's done in the normal course of business. That's already provided for under current law.

Senator Martha Fuller Clark, D. 24: Mr. Long, I do have one question for you, as it's going to better be ....

Mr. Long: If it's really pressing. I'd prefer to go through and then answer questions.

Senator Martha Fuller Clark, D. 24: Thank you.

Mr. Long: On page 13, is what some of the rough estimates were in 2005, as compared to 2008. You know, lots of things have gone up, as others have. In fact, everything all around us, all around us, in all the infrastructure projects and construction projects, you see the same sort of thing going on. That's why, when we get into construction projects, we try to lock into the costs as soon as possible, so that we can avoid further increases.

Page 14 just tells you a little bit more about what drives those costs. I think the things that are really interesting, hopefully you will find it interesting, is if you go to page 15, and this is a chart. This is not prepared by Public Service Company, this is prepared by a very renowned firm called Cambridge Energy Research Associates. Okay, we took this directly from their research. And this is just, and this again is not speculation. This is not speculating about the future, this is what actually happened, okay. And so this is what actually happened to power capital costs between 2005 and today, and you can see, you can see that all projects throughout the country were experiencing the same sort of price escalation as we did. So that means that all of our competitors, others had their costs going up too, which means that relative, the whole market went up. So when you see scrubber costs go up, sure they did. But so did everything else and so relative to the market, we're still very good.

And the same sort of thing on page 16, you see iron and steel, cement, and they went up in great amounts from 2005. And of course anybody in the construction business knows that, anybody in the power business knows that. And the same sort of thing, if you go to page 17, copper, nickel, you know increased. They're still all up, very substantial increases. I give this to you only to point out that, you know, obviously a project of this type is very complicated and no one expects you to be experts in project management. Nobody expects you to be experts, but we are, and these are things that really, I think, would indicate to you what drives these costs up and it's not unique to Public Service Company. As I said, Gary Fortier will compare it against other scrubber costs around the nation. You'll see the same sort of thing, that we're very competitive and we're very much in line with what others are experiencing.

And page 18 is a little bit more than that. There's a little more information on the cost differentials that have occurred. And really, you don't need a bill, you don't need legislation to understand this data or to get it. I mean the PUC has access to this data without any law changed, and they certainly will look at it before, as Senator Gatsas says, anything goes in rate. I mean you really should take comfort in that. If they think we did anything wrong, or didn't do anything well, they will certainly let us know, and we will be hearing that one out too. So, I don't, you really don't, there's nothing to do in a future study that will help you understand the costs of the scrubber.

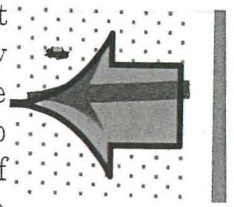
And our whole approach, on page 19 there, and it's been very, very successful and our award winning wood plant, it's gotten, five, six, seven awards, national, international, construction awards, engineering awards. We're using those same practices that we used in that award winning project on this, and that's not, page 19 just tells you a little bit more about what those are.

And page 20 is a really coming a little bit at it from the customer angle, which of course is really a progress INAUDIBLE we use on every decision that we make, but we agreed this a very good project for customers, also. It's going to provide them with energy security, provide them with economic power, and as was said, the Public Utilities Commission will look at this thoroughly as they always do.

And I think we need to remind people sometimes, so it will help you put their allegations in perspective, is New Hampshire has an open access system, and many of you were part of that. Many of you created that law and that policy, and certainly I was part of it. And what that means is that any customer, any customer can choose a power supplier. Now we know on a practical

level, residential customers don't get that choice because people aren't offering that. But we know on the business side, commercial customers, we know that they can and do choose power suppliers other than PSNH.

Our role, our role as set by state law, our role is to provide power to customers when they haven't chosen a supplier. Some people call that the supplier of last resort. It just so happens that most customers do not choose a supplier. But commercial customers can. So when a commercial customer says, I'm concerned about the cost, you know, I don't want to be flippant about this, but if they really are concerned about the cost and if we really aren't low cost, they can go somewhere else and they can completely avoid the costs of a scrubber. But that's not, you know, what we're trying to do is to have the lowest cost power that we can for the benefit of customers. But if people think that we're out of line, they have recourse. They have recourse through prudency review and they have recourse by, they can make a choice for a different power supplier. And that's just the point that sometimes is lost when people make allegations and ...



It's interesting to me that Senator Janeway says this isn't about cost. And I think he's right. I agree with him. This isn't about cost, this is about people who want to shut down Merrimack Station.

On page 22 is the project benefits and I've mentioned many of them. Of course, jobs right now is always very important to us, and I thank people for complimenting us for how we treat employees. I'm one of those employees, and we always try to treat our employees well, and we always try to treat our contractors well, and we always try to treat people who work on our sites well. And we're looking forward to having many of you on the site and working hard. We know you do good work. We've had lots of experience with contractors doing great work and we're going to do it again. But jobs is very important. The local economy.

I mentioned passenger rail. There will be more and railroad help, we talked about that. I talked about the energy values of this plant already. I mean the values to me are just so overwhelming, just as some people would say a no brainer, that you really want to maintain a plant like that, and you really want it to be as clean as possible.

Regarding Senate Bill 152, I tell you, it's very unusual for me to testify before you these days, so the reason I'm here is because I just think that it is so, it's such a dramatically negative impact and I really need to, really need your vote against this bill. It is not a simple study bill. It is far more serious than that and, you know, my point of view, not a point of view, it's really my experience. As I say, you can spend any amount of money you want on this

study and it won't tell you the future. I think Senator Gatsas had exactly the right question. What are you going to do with it when you get it? Because at best, it's going to be speculative, it's not going to tell you anything. And all it will do is feed the fire and all it will do is cause more fighting and disagreement and people following different agendas.

As I said, as an electric company what we do is we try to provide for certainty in an uncertain world. And one way to provide for certainty in a very uncertain world is to make the power plants as clean as possible and to install the scrubber. As I said, the scrubber is really our hedge against federal regulations. You know, I'd rather do it now when it's less expensive than to do it five years from now, when there's federal regulations, when every other power company in the country is putting in scrubbers. It's better to do it now, and I think it'll do us well.

Senator Martha Fuller Clark, D. 24: Mr. Long?

Mr. Long: Yes, ma'am?

Senator Martha Fuller Clark, D. 24: I wonder if it would be possible to wind this up.

Mr. Long: I'm just about finished, as you can tell. I'm on slide 25, with only a couple other ...

Senator Martha Fuller Clark, D. 24: You've provided a lot of very good information in there and it's not that we don't appreciate and that we don't take your testimony seriously, but you have spoken for 30 minutes.

Mr. Long: Oh, I'm sorry, yup, a little bit longer than I normally go. But if, Senator, you could just bear with me a couple more minutes, I think I can wrap this up.

Senator Martha Fuller Clark, D. 24: Certainly.

Mr. Long: Thank you. On page 25, I guess you can read it at your leisure, but I just want to point out to you, because some people think the study is going to provide answers, and it won't, and I want to tell you what it won't give you. It certainly won't tell you what the cost of the scrubber is or what Merrimack Station's fuel source is. We know that. And it won't tell you what the price of oil, gas or coal, and it won't tell you what future regulations you're going to have. So it really, you can spend money and you can have a study, but to what end? I think the only end is, I guess, give you a platform to say shut the plant down.

Page 26. I guess I'm done, Senator. With that I can just, I really do want to focus on just one more slide before I leave, and it's slide number 28, and many of you have heard me say this before. And it's just one slide, but I would tell you, Senators, in some ways this is the most important slide in the whole package. Because I really don't think we should be here today talking about Merrimack Station. I think that should simply be going forward in the way that we've all agreed.

What we should be talking about is how can we have more renewables. And what this page is saying is what PSNH is doing and what we think should be done. And you can see we think energy efficiency is a huge part of our future, and that's what we should be talking about. How do we get more of that? How do we do that well? How do we work together on that? You know, how do we keep looking for innovative ways in our power plants? You may have read, you may have heard, that we're going to test burn cocoa beans in our power plant. Those are the kind of things that we do and then invest in renewable energy projects. That is not going as fast as I would have liked, and I personally think that you can never have too much renewable energy power. And you all know my position, that PSNH would like to build an INAUDIBLE and employ some of these people on that front too, doing renewable energy projects. But you know that for three years now, the Senate has said no. But we're not here today to talk about that. But I think that's really the sorts of things that we should be talking about, instead of having to spend so much of our efforts doing something that has already been done, which is put a scrubber at Merrimack Station.

I guess finally I just ask you for your support, for the all these people in this room, for our customers, for our energy future, that you vote against Senate Bill 152. Thank you.

I would like, Senator, to bring Gary Fortier up for just a minute so he can give the scrubber perspective, too.

Senator Martha Fuller Clark, D. 24: Thank you very much. I would like to say that I look forward to working with you on making sure that we can provide the transmission to the North Country so that whatever projects are being, moving forward in the North Country are going to be able to come to fruition. Without transmission, nothing can move forward, so we know that you're a key player in that and we do look forward to working with you to solve that problem.

Mr. Long: And I, too, with you, Senator, am interested. And there are some even more substantial things we can do with transmission than the northern

route; but we certainly want to do that. And I will tell you, there's renewables that we can do now that don't require transmission. So, all those things I think we should pursue together.

Senator Martha Fuller Clark, D. 24: Absolutely. I wanted to ask you one question, which was some concern that I have that when you're looking at the cost of commodities, that your chart ends in 2008. It doesn't show what's happened to commodities since the market of last summer, which we know, the costs were very high. The costs now have come down. Do you have the stability in your contracts? I know that you said ...INAUDIBLE

Mr. Long: Yes, Senator, I would say we're in very good shape, and I really want to compliment the team, the PSNH engineering team and project team. I'm very, very comfortable and very pleased with their, you know, marvelous execution so far. And yes, we provided, we have room in the contract. We provided for escalation of materials and we provided for contingencies. If we don't have to use those escalations because the markets have changed and some prices of some things have gone down, or at least stayed flat, because sometimes we built in escalations in case they didn't stay flat. So, yeah, we are already seeing reductions in costs that we are capturing as we go forward. So, yes, we believe that that's why, as I mentioned earlier, this is like the highest it would ever be, 457, and you know, again, until you run the course you won't know what the final numbers are. But our team feels very confident that there's things that we can exercise along the way.

The bad news is we're in a recession. I mean, nobody wants that. But if you're in that circumstance, you might have some leverage to get some cost savings for materials, but there still is a world demand for scrubbers and there still is, it's still a very vibrant market.

Senator Martha Fuller Clark, D. 24: INAUDIBLE

Senator Jacalyn L. Cilley, D. 6: Thank you, Madam Chair, hold it down, okay. Thank you, Madam Chair. Mr. Long, I have been following this now for weeks, and I have heard evidence on both sides of the fence about, you know, whether that plant is actually an integral part of the, you know, the supply of electricity, and that we really could do without it and have adequate supply. I'm wondering if you could speak to that, and I'm also wondering why, doesn't ISO New England issue, I think it's FERCs, it's been a little while since I've visited those, that suggest a concern about supply in the future?

Mr. Long: Thank you, Senator. I tried to keep things from getting too complicated, because electricity is fairly complicated. But the short answer

to your question is that plant is absolutely critical to supplying our customers. Okay, now we have to distinguish our customers from the rest of New England. But that plant is clearly used to serve our customers, and we don't have enough power to serve our customers. We're buying power on the wholesale market. We buy 300 to 400 megawatts of power on the wholesale market. So, certainly from the perspective of the economics to our customers, it's critical.

When you look at New England generally, and we are operating as a single region, the recession has resulted in less electric load now than we had earlier. So, I mean, the recession is having a very large impact on everyone. So right now, and I think Senator Janeway, you know, said that prices are low. Prices have gone down, and as I said, I've seen many cycles of up and down. I mean, if you want to bet the farm on the prices today, I certainly wouldn't. But, you know, so prices are low now, which is good. It's kind of an offset to the recession. But no one expects that to hold. And so there's enough power in New England. There's enough power in New England. I should say it this way, on paper, there's enough generating capacity to serve the load. And there isn't any real load growth happening in New England right now.

But that doesn't mean, that doesn't mean that's economic for customers, it doesn't mean that at all. And it doesn't mean that that power is available all the time. We've had two times in the last, I think, three years where there's been a shortage of gas supply, and what happens when there's a shortage of gas supply, is several of the gas plants in New England can't run and I think the mention of our turbines, our combustion turbines running is kind of the result, sometimes the result of plants just not being able to start up. Sometimes it's just the result of plants just not being able to run. And that's what happened. You know, there's destruction in the gas supply and we were called on to run anything and everything we could so New England would have enough power, and that doesn't happen often, but it can happen. And so, in our business, that's why I say, it is so important to have fuel diversity, it's so important to have flexibility, and that's one of the things that Merrimack Station does for us.

Senator Martha Fuller Clark, D. 24: Thank you very much. Senator Carson.

Senator Sharon M. Carson, D. 14: Thank you, Madam Chair. And thank you for your testimony this morning, Mr. Long.

Mr. Long: Thank you, Senator.

Senator Sharon M. Carson, D. 14: I pulled some of the testimony from the original bill that established the scrubber project, and I discovered that not only are we looking to reduce mercury emissions, but we're also looking to reduce the sulfur dioxide emissions. And that is really substantiated in the program that you provided us with this morning. One of the things that I did not know was that we were paying for these sulfur dioxide credits. Are we still paying for those?

Mr. Long: Yes. We, as an emitter of sulfur dioxide, we have, there's a cap and trade system, you know, much like what people talk about for CO^2. Not the same design but the concept. And it's been in existence for a number of years and it's been proven to work very well, about reducing sulfur. And so, you know, it wasn't required by law to reduce sulfur, you know, that mercury law. It was really focused on mercury, as others have said. But at that time, we did a two-fer, those were the kind of words used back then. We get to have two major reductions with one piece of equipment, because these flu gases, desulfurization are mainly for the purpose of reducing sulfur. So we got a huge reduction in sulfur, which means we avoid having to buy sulfur credits on the market, on the cap and trade market. So that produces economic value, it's an offset to the cost. Not an entire offset, but it helps offset the cost and so, yeah, it's a very good thing for us. And it helps us look at different sources of coal, because if the coal has a little more sulfur in it than the coal we'd normally buy, but we now have a way of getting rid of the sulfur with this device, which means we're open up to more markets, and that affects rail in a positive way as well as cost.

Senator Martha Fuller Clark, D. 24: INAUDIBLE

Senator Sharon M. Carson, D. 14: Thank you, Madam Chair. So if you were to give us some sort of an estimate, what do you think would be the cost benefit to the ratepayer?

Mr. Long: I guess I'd like to do that as a follow-up, because I'm not an expert and I know that two years from now, someone will say, gee, Gary, you said sulfur credits were this, and the market changed and the facts. So, you know, again, it would be an estimate based on today's costs and I think one of our staff can certainly provide that for you, Senator.

Senator Martha Fuller Clark, D. 24: Senator Odell.

Senator Bob Odell, D. 8: Thank you, Madam Chair. A couple, Mr. Long, thank you for your testimony. A couple of times this morning you have mentioned that there's a cost for this study of a $1 million or $2 million. Who would be the payer of that?

Mr. Long: You know, Senator Odell, I didn't mean to imply that this would cost that much. We're not advocating any study, so it costs zero if you ask me. But I'm just saying, I have seen studies where you can pay consultants $1 million to do a study, and I personally would not use the results of that study because of speculation. And if you spent $100,000, $200,000, $1 million, my point being that money will not buy you an answer. That no matter how much you spend, you can look at what you think is the world's renowned expert, you know, but they can't tell you what an oil price is going to be three years from now, four years from now. There are some markets that you can buy and sell one or two years ahead. You can't buy five, six, ten years ahead. Nobody's foolish enough to believe that they can forecast.

Senator Martha Fuller Clark, D. 24: Follow-up.

Senator Bob Odell, D. 8: Mr. Long, my question was, if it costs a dollar or it costs a $1 million to do this study, who ultimately pays for the study?

Mr. Long: I don't know. I guess that would be for you to decide, but if you vote the bill down, you don't have to decide. But you know, it's, I would think that it would be a bad use of money from customers, so I certainly hope our customers don't have to pay for it.

Senator Martha Fuller Clark, D. 24: INAUDIBLE

Senator Bob Odell, D. 8: Thank you, Madam Chair. I understand correctly and some of the concern is that you've had 33 years of experience, you must have had projects like this in the past, and I know you mentioned the Shiller Boiler, where you are asked, you are legislatively told to go ahead with the project or you initiate a project. You spend the money and then the Public Utilities Commission looks at that and says, yes, this cost is in, that cost is out. In other words, the Legislature has ennobled (sic) the Public Utilities Commission to fulfill that role. Is that a normal standard, that lookback, in terms of what will go into the rate base?

Mr. Long: It is the normal standard for the Public Utilities Commission to review our actions and our decisions, and it's done in hindsight. So it certainly presents business risk, as you might have a difference of opinion. We might think we made a good decision, somebody else might think we made a bad decision. But I think the Commission has found over and over again that we're making good decisions. But yes, that's normal course. And that's okay, we're totally prepared for that and we're totally used to that.

What is difficult for us because, you know, we're really, whatever we do affects customers. You know, we're a regulated company, we don't get market prices. We don't get the profits that a nuclear plant gets when the market prices go up, you know, or any other plant if it's not regulated. So we have to be very careful. First of all, because we have that scrutiny. Second of all, you know, it affects customers. So we're basically very conservative. We think we're very innovative when it comes to things like wood burning or like cocoa bean shell burning or, you know, renewable power. But financially we have to be very, very conservative and we have to be very sure of what we're doing, because if we're reckless or if we're making bad decisions, it'll hurt, it'll come back on us.

Senator Martha Fuller Clark, D. 24: Thank you very much.

Unknown: My name's Lynn INAUDIBLE and INAUDIBLE for PSNH. And this question was asked of us awhile ago because I think INAUDIBLE question, whether or not INAUDIBLE.

Senator Martha Fuller Clark, D. 24: Could you just wait one minute. We'll be able to get your answer, but it won't INAUDIBLE.

Mr. Long: I must have said something that my staff disagrees with me, so no.

Senator Martha Fuller Clark, D. 24: INAUDIBLE. What I would like to do now . INAUDIBLE to come forward, will not be able to INAUDIBLE this afternoon. It is my intention to break the morning session at noon and reconvene at 12:30. At that time, I will ask the representative INAUDIBLE to come forward. Is that?

Mr. Long: Thank you very much, Senator. That's perfectly acceptable, just as long as you get the information, I think you'll find it useful.

Senator Martha Fuller Clark, D. 24: INAUDIBLE, so wait before the public can INAUDIBLE, we'll hear from Senator D'Allesandro. INAUDIBLE if you could line up, I will call on you.

Senator Lou D'Allesandro, D. 20: Thank you, Madam Chairman, and distinguished members of the Committee. For the record, my name is Senator Lou D'Allesandro, I represent District 20. That's Manchester, Wards 3, 4, 10, 11 and the Town of Goffstown.

I come before you in opposition to Senate Bill 152. I'll be extremely brief. We as the Legislature mandated that PSNH do this. We told them to do this

because we were all concerned about the health and welfare of our children. We were concerned about the health and welfare of the communities that we represent. We went through an exhausting situation in the Senate. We said do this! So we have given the mandate to do it. It seems to me we ought to follow through. When costs are accumulated, you can look at costs. The Public Utilities Commission has that responsibility, but to do anything in any way to mitigate this project, I think is against the public interest. I want to very brief, because we've got a lot of people to hear. But again, we championed this cause in the Senate in order to protect the public. I champion the cause of letting it go forward. We've got a lot of men and women who need employment. The employment is there. The job needs to be done. We can look at the costs as they come before PUC if there are any problems after it's done. But it's good public policy to carry through with items that we have mandated that people do. Thank you very much, Madam Chairman.

Senator Martha Fuller Clark, D. 24: Thank you, Senator D'Allesandro. Are there questions from the Senators? Seeing none, I'd like to call INAUDIBLE. If you could introduce yourself as you come forward.

Edward Foley: Good morning, Madam Chairman, and good morning honorable members of the Committee. My name is Ed Foley and I'm President of the New Hampshire State Building and Construction Trade Council. And I'm here today to speak on behalf of my members, who I would like to ask to stand up, who are here. And in the essence of saving time, they will not speak, but they have all signed in the sheet opposed to this bill and we are opposed to the amendment as well. Thank you, brothers and sisters.

Madam Chairman, good morning, and thank you for allowing me to speak. I am writing on behalf of the New Hampshire and Construction Trade Council in regard to the clean air scrubber project at Public Service Company of New Hampshire's coal fired Merrimack Station in Bow. While my comments pertain to an important, my comments may be lengthy but they pertain to an important public policy matter. I will read it in its entirety.

The New Hampshire Building Trades represents more than 5,000 highly skilled New Hampshire workers, from 19 union locals encompassing all skilled crafts. We also represent their family members, their wives, their children, their mothers, their fathers, their grandparents and all their relatives. As you may know, in 2006, the New Hampshire Legislature passed and the Governor signed into law House Bill 1673, which represents, which requires the complete installation, no later than July 1, 2013, of scrubber technology, wet flu gas desulfurization technology at the Merrimack Station power plant in order to achieve at least an 80 percent reduction in the

Station power plant in order to achieve at least an 80 percent reduction in the plant's mercury emissions. In so doing, the Legislature found that it is in the public interest to achieve significant reductions in mercury emissions at Merrimack Station as soon as possible. And that scrubber technology achieve significant emissions reduction benefits including, but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter and improved visibility, otherwise known as regional haze.

Currently, workers from New Hampshire building trades unions have already begun site preparation work for the scrubber installation, and skilled New Hampshire workers are slated to begin the major installation work by March 2009 in order to complete this environmentally essential project on time. Unfortunately, there is now a move legislatively and via litigation to delay this project, so its costs can be studied and to determine if New Hampshire would be better off replacing this coal fired electrical generation facility with non-coal sources. We certainly understand the concerns articulated by various parties about moving New Hampshire toward alternative sustainable and non-fossil fuel energy sources as rapidly as feasible. In fact, our affiliated unions are actively engaged in further enhancing our existing construction expertise related to solar and wind power, turbine retrofits, energy efficiency and other sustainable renewable energy sources. Therefore, we have both the interest in and capacity for being a key part of New Hampshire's transition to a greener energy mix.

However, we are deeply troubled that the current conversation about Merrimack Station clean air scrubber appears to be framed as an either/or proposition, when what we really need is to be focusing on is both/and. In other words, the Legislature must keep this two year old commitment to every New Hampshire citizen impacted by the emissions from the Bow coal fired plant that a clean air scrubber will be installed without delay. At the same time, all stakeholders concerned about our state's energy generation and utilization must come together to forge a common vision for a realistic transition plan and time frame for moving New Hampshire substantially forward in terms of planning, siting, permitting, financing and building alternative energy power sources.

Further, these sources must have a generation capacity of such a magnitude that they can truly meet New Hampshire's electrical energy needs. The New Hampshire Building Trades Council is ready and willing to be an active partner in this planning and building process. It is critical to keep in mind, though, that we are not talking about months in regard to such transition, planning and execution. We are talking about years. The nationally regarded, the nationally regarded University of Southern California Energy Institute, which is dedicated to helping communities transform to

environmentally sound energy choices, perhaps said it best when it noted that any significant shift to alternative fuels will take years or decades. And I can tell you from my 38 years experience in the building trades, it will no doubt be decades to accomplish. In the interim, it is essential that conventional fuels be used more efficiently and their environmental consequences mitigated. Sounds like the scrubber project.

Here are the facts that we hope you'll keep in mind as the policy discussion takes place regarding the installation of clean air scrubber technology at Merrimack Station. The estimated $250 million installation costs from 2006 was revised two years later to $457 million. The cost increase was attributed primarily to raw materials and materials transportation cost increases. As every home and commercial builder knows, costs for materials have increased exponentially in the past years. Now that we are seeing a downward shift in gasoline prices, we expect that materials transportation costs may level or moderate, for the short term only, and we certainly hope the scrubber project can take advantage of that price leveling by beginning quickly.

Currently, PSNH's Merrimack Station supplies New Hampshire businesses and households with 433 megawatts of power, base load, approximately 35 percent of PSNH's electricity generation portfolio. Some would have you believe that New Hampshire can shut the door on coal after a several month study period, and somehow construct alternative facilities to produce 433 megawatts of cheap, clean and reliable replacement power in a matter of months. If this were so, we'd be ready to build those alternative plants today.

But we urge you to keep this policy discussion in the realm of the realistic. The reality is that, even if New Hampshire policy makers and community partners were to start electrical generation capacity, further there is also the issue of transmission line capacity. We see great potential for developing exciting alternative energy facilities in New Hampshire's north country – from biomass to wind farms and more. But currently we lack the transmission capacity to get the resulting energy from New Hampshire's north to the bulk of the electrical users who are in New Hampshire's south. We should make enhanced transmission capacity a priority for any energy related federal economic stimulus funding received by New Hampshire, at the same time we are moving ahead and cleaning New Hampshire's air through construction of the Merrimack Station's scrubber.

Some have suggested that PSNH be directed to shutter or dismantle the current coal fired facilities in Bow, and immediately build on the same site a 400 megawatt combined cycle natural gas facility. Not only is this not realistic as a near term solution, but one has to ask why it makes any sense

whatsoever to tear down one transmission fossil fuel facility in order to build another transmission fossil fuel facility. Further, has any sound, impartial analysis been undertaken about the practicality or desirability of such a switch? Assuming it's even realistic in terms of energy planning and economics, the consumer interest in the optical energy mix for New Hampshire's long term future.

Some would like to shut the door on coal, some who would like to shut the door on coal have estimated that $457 million is not the real cost of the scrubber project, and that rather, it could actually cost more than $2 billion. These projections are completely speculative and full of what ifs. Also, this speculation about dramatic cost increases includes projections about regulatory changes that will impact the entire electrical generation landscape, not just Merrimack Station. Further, we believe this conjecture was done with no knowledge of existing project contractual agreements that, in fact, are structured with the goal of ensuring an on time, on budget project. However, if not allowed to begin on time, this project's costs will go up substantially. It is well known that construction delays increase construction costs. This is an economic reality for any current construction project, whether it is a house, a state office building, a highway bridge, a public school, a county jail or power plants.

Some are saying that they simply want to delay the beginning of the scrubber construction for a very short period so its cost benefit can be further studied. What might be the possible outcomes of just a few months of study? Let's say that in two months of study, the studiers say we shouldn't spend $457 million on scrubbers because coal is so yesterday and not tomorrow. What, and other New Hampshire citizens, what then? Do we not install the scrubbers? Then what do we tell all those who live in or near Bow and other New Hampshire citizens who are impacted by the existing mercury emissions? Do we tell them, never mind, we're breaching the commitment we made to you two and a half years ago? Do we tell them, just keep breathing the unscrubbed mercury emissions? Or do we padlock the doors to Merrimack Station? And if we do, where will the replacement electricity for southern New Hampshire users come from? How will it get to their homes and businesses? How much will it cost? And realistically, how long will it take to plan and build these new facilities that will replace Merrimack Station's 433 megawatts? And what do we tell the several hundred New Hampshire workers who are now trained and poised to begin installation of the scrubbers and to pump the resulting good wages into the New Hampshire economy?

This letter is not intended to take a position on the use of coal as a power source of tomorrow. Rather, it is meant to promote a realistic policy

discussion for today. Like it or not, we already generate a substantial portion of New Hampshire's electricity from coal. This is a reality. It is also a reality that the Legislature has already studied the need for clean air scrubbers at Merrimack Station, and has delivered an unambiguous mandate that it is in the public interest for the scrubbers to be installed. It is a further reality that hundreds of New Hampshire workers expect to begin this project in a matter of weeks, and as I mentioned earlier, we already have 70 workers on that site, which has already generated 12,500 hours up to today.

The men and women of New Hampshire Building Trades Council implore you to not get confused into thinking you have to choose between the Merrimack Station scrubber project and moving toward a non-coal future if that ultimately is an energy policy objective for New Hampshire. This is not an either/or conversation. Let's get started on scrubbing the Merrimack Station emissions today and let's also move aggressively today to plan for whatever is deemed to be the most desirable energy mix for New Hampshire for the decades to come.

The members of the New Hampshire Building Trades thank you for your attention to this matter, and I just wanted to give you some projected costs on replacing that power. We have estimates that to replace the power with wind will cost $3 billion, and to replace that power, 450 megawatts, with wood will be $1.5 billion.

Our members and their families are here today because they care about the health of their families and they care about the health of their children. This project is a great thing for New Hampshire. It's going to clean the air, it's going to clean the waters and streams. We'll be able to eat the fish more than once a week. This project also generates jobs for my members, good jobs, good paying jobs with wages and benefits. It also will train people for a skilled work force for New Hampshire's tomorrow. We here ask you today to please vote this bill ITL and support the scrubber project. Thank you.

Please see Attachment #3, Edward Foley's testimony.

Senator Martha Fuller Clark, D. 24: Thank you very much, Mr. Foley. No clapping please. We appreciate your enthusiasm but we do have decorum to maintain. Are there questions from the members of the Committee? Seeing none, I would like to call upon the next speaker.

Jameson French: Thank you. Thanks, Senator Clark. I'm Jameson French from Portsmouth, New Hampshire. Appreciate being able to speak early because I have to catch a flight. I'm President of Northern Forest Products

in Kingston, New Hampshire, and my family's been in the hardwood lumber industry and forest products industry in New England for the last 125 years.

We still employ 30 people in New Hampshire. I say still because we're part of a severely challenged industry. In fact, hearing these comments about prices going up or staying stable, in the wood business we're looking at 30, 40, 20, 30, 40 percent price decreases in most of the products. Most of the sawmills and the producers across the state are shut or laid off shifts. We are a severely challenged industry. We've also faced for many years in New England excessive, very uncompetitive power costs in relation to Quebec, our competitors across the border in Quebec, and also our competitors in West Virginia, Pennsylvania and other parts of the state.

I also should say I'm a member of the Governor's Climate Change Policy Task Force, and I'm also chairman of the Hardwood Federation in Washington, D.C., which represents about 14,000 hardwood related companies across the United States. Until probably, at least last year, we had over a million families represented in the hardwood industry. I also might add that I have remained a registered Republican, primarily because of my fiscal conservative roots.

I also want to add that I have huge personal respect for Gary Long and feel that PSNH has been a very good corporate citizen of our state. I would not be here today if this project was on budget. I strongly supported the $200 to $257 million scrubber to reduce mercury and SO^2 if it was crafted out. But as a representative of an industry that can't afford any cost increases, I'm deeply concerned on the impact of this open-ended project. I'm floored, quite honestly, that in this deep recession the price for this project has not gone done, instead of nearly doubling. All the raw material costs involved, from concrete to steel to lumber, copper, have dropped substantially, 20, 30 percent in many cases. I don't understand why PSNH isn't able to establish a fixed price and why the costs are so high. In these very, very troubled times, it seems only fair and appropriate that the ratepayers of the state should know what the costs will be and why it has gone up so much.

It's mind boggling that this Legislature can have huge battles over $3 and $4 million funding for LCHIP, or drug and alcohol prevention funds, and doesn't seem to be very worried about a potential 2 or 300 hundred million expenditure that we the ratepayers, the taxpayers, will be paying for. It seems very appropriate that the study that SB 152 calls for be done and done soon. We ratepayers need to know what the impact of this project will be on our future energy costs. We all know that Merrimack Station is there for the immediate future. But in the long term picture of energy generation in New Hampshire, is a $400 or $500 million, or more, investment the right thing for

the state and for our ratepayers? We all need more information to make the decision.

Thank you very much.

Senator Martha Fuller Clark, D. 24: Thank you very much, Mr. French. Are there questions from the Committee for Mr. French? Thank you.

Mr. French: Thanks.

Cameron Wake: Good morning, Madam Chairman, and thank you for the opportunity to speak today. My name's Cameron Wake, I'm a research associate professor at the University of New Hampshire. Also the Director of Carbon Solutions New England, and also a member of the Governor's Climate Change Policy Task Force. I'm here today to support, to speak in support of Senate Bill 152, in support of research and analysis that informs decision making.

I'd like to begin and focus most of my comments today on the issue of uncertainty. The focus of my research is the earth's climate system. While our understanding of the earth's climate has improved significantly over the past three decades, there remains considerable uncertainty in our understanding of the earth's response to recent rises in greenhouse gases in the atmosphere. Over the last five years, the scientific community has been surprised and dare I say, in some cases, shocked at how our climate system is changing far more rapidly than we predicted even five years ago. This is especially true for the precipitous reduction in the extent of our sea ice during the summer of 2007, over a 25 percent reduction compared to previous year. Why is this important? Because as more sea ice disappears, more of the solar radiation that used to be reflected back into space by the white sea ice is instead absorbed by the dark surface of the ocean, resulting in more warming of the surface and more sea ice lost, a vicious circle which we call a positive feedback loop.

In addition to the disappearance of artic sea ice, scientists have tracked a dramatic increase in the melting of the Greenland ice sheet and subsequent doubling in the velocity of large ice streams draining the ice sheet. Our recent paper in Science magazine provides a sobering analysis. The good news? If melting of Greenland ice sheet continues to increase at rates we've measured over the past decade, it is unlikely that sea level will rise by more than seven feet by the end of the century. The bad news? Sea level might rise by seven feet over the course of the next century.

While scientists can provide society with broad outlines, we are unable to pinpoint exactly how our client system will change over the next century, for a whole variety of reasons. The largest uncertainty in our future climate is that the climate that our children and grandchildren will inherit is the amount of heat trapping gases that are emitted from human activities. Despite these uncertainties, we know for certain that we can reduce the magnitude of future climate change by reducing our emissions of heat trapping gases. We also know that the only way to avoid catastrophic climate change is to begin right away to reduce these gases. Any margin of error we had for leeway of acting has disappeared in the last 20 years of inaction.

Alright, so why the science and why the uncertainty? I firmly believe that informed policy decisions require the best possible information. Detailed research and analysis can and should serve to reduce the level of uncertainty regarding the impact of any policy decision. I believe that the analysis that we did at the University of New Hampshire for the New Hampshire Climate Change Policy Task Force on both carbon emissions and the economic impact of a broad range of actions in transportation and land use, residential and commercial and industrial buildings, energy generation and use, and agriculture, forest, ??? (2:20:45) waste, provided decision relevant information to the Task Force to make informed decisions. The results are striking. Investment in energy efficiency and renewable technologies has a significant positive economic impact for the state. You'll be hearing more about that when the Governor releases the report on March 25th.

I believe the same issue is true for the question raised in Senate Bill 152. Is the estimated cost of $457 million to install the mercury scrubber at Merrimack Station in the best interests of the State of New Hampshire and in the ratepayers? Much has in fact changed since 2006. Not only the estimated cost of the project or the reduction in our fixed sea ice. It is also clear that the Obama Administration and Democratically controlled Congress, we are headed for a nation constrained by carbon, likely through the passage of some form of cap and trade bill, in the not too distant future.

It makes perfect sense to me that we'd take this opportunity, given changes that have occurred and that are likely to occur in the near future, combined with the relatively long payback period of the scrubber project, to investigate the costs of future electricity generated by Merrimack Station in a carbon constrained world and the cost of developing alternative sources of energy and the costs of carbon capture and sequestration. Informed policy requires the best possible analysis and while this analysis certainly won't remove all of the uncertainty, it will provide important decision relevant information upon which informed policy is based.

Thank you.

Senator Martha Fuller Clark, D. 24: Thank you very much, Mr. Wake. Are there questions for Mr. Wake? Thank you.

Sarah McGraw: Hi, my name is Sarah McGraw and I'm a freshman at the University of New Hampshire. I've been lucky to grow up living in a clean environment, as a kid playing in the woods and streams, and hiking in the beautiful mountains of New Hampshire. Some are not so lucky, though, because the mountains and valleys of Appalachia have been ravaged by mountain top removal in the search for more coal, while mountains are destroyed because of the coal we burn here in New Hampshire. Just because I don't live where coal is mined, doesn't mean we're not affected. As you know, a large percent of New Hampshire's emissions, along with the endless amounts of pollutants into our woods and streams, come from the power plant.

The economy is not going to drastically change any time soon. So think about jobs for the future. Let's train our workers to be skilled in long term jobs. We can save our mountains, our air and our environment if we start to invest now. I'm an environmental conservation major and I hope to have a job coming out of college to pay for my increasing debt. If we continue to only look at short term solutions of the energy crisis, specifically coal plants, then there will not be good paying jobs for millions, which is not that far into the future. I am very hopeful that the U.S. and New Hampshire can be a leader in renewable energy. But the only way to move ahead is if we do not hesitate to spend our money on renewable energy. The sun, the wind and water is a constant renewable, re-useable resource. Haven't we waited long enough? How much longer can you afford to rely on a dying energy resource? How many thousands of jobs will be lost in the future and what kind of future will my children have if we don't look at real energy solutions now? And that is why I support House Bill 152. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you very much. It's come to my attention that Representative Pepino is here. If you could come forward at this time in order to speak, we'd appreciate that.

Representative Leo Pepino: Thank you, Madam Chairman.

Senator Martha Fuller Clark, D. 24: You're most welcome.

Representative Pepino: I'll make it very short. I worked at Unit 1 in Bow, I worked at Unit 2 in Bow. Unit 3, well the scrubber's, I'll call it Unit 3 for

now. You've been talking about it for two years. Since then, the price has doubled. When we had Seabrook, you talked about that for I don't know how many years. The price of that tripled. So let's pass this, get these guys back to work. If I was one of them, I'd be working. Get these guys back to work and that's all I have to say. Let's get things moving. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you very much. Are there any questions?

Claire Sebilla: Hi, my name's Claire Sebilla and I'm a sophomore at the University of New Hampshire. I thank you for the opportunity to speak here today.

I'm here because I'm deeply concerned about our energy future of our world and our nation, but really, most importantly, the future of New Hampshire. I will, hopefully, be on this planet for many more years. And we cannot afford to only see the short term effects of this bill. I've always had a hard time adjusting to change. Most of us do. But because of the urgency of our current situation with regards to the economy and the predicted effects of climate change, we must put convenience on the back burner.

On my way to Concord this morning, I heard on the radio that New Hampshire will receive tens of millions of dollars from the federal government for weatherization and energy efficiency programs. This is great that the new administration recognizes the need to address our energy needs and how we use energy. One of the concerns raised this morning was that renewables like solar and wind are intermittent or unreliable. But that's simply not true. The problem lies with coal and other fossil fuels, because they're not renewables. These are the energy sources that are unreliable, because they come from finite resources. Eventually, we'll be forced to adjust our energy usage, so why not look ahead and act now? By passing this bill, New Hampshire can take a step in the difficult but necessary journey towards a clean economy, one that employs New Hampshire workers creating renewable energy. My future depends on it and our future depends on it. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you so very much. Are there any questions for Claire?

Abby Gromberg: Hi, my name is Abby Gromberg. I'm a freshman at the University of New Hampshire and I'm outnumbered today, saying that I hope that the bill passes and ultimately closes down the power plant. I feel that the scrubber is a short term solution and I'm here today as a voice and as a

face of future generations, looking for steps such as closing down the power plant, that will be that long term solution. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you very much. Any questions?

Zo Tobey: Hello, thank you for the chance to speak. My name is Zo, Zo Tobey. I grew up in Nashua. I moved to Lyndeborough with my folks. Now I'm living in Keene, so I've gotten to see quite a few parts of our state. And I have the distinct privilege of working as the northeast organizer for the Sierra Student Coalition. And from my job, this is really cool, my job is to coach and mentor young people throughout the northeast who are organizing to save our climate, save our economy and to save our future. So I have a great job.

And I am in support of this bill. To me, the choice that we face is actually an either/or, and I'm a pretty nuanced guy. I see the world in grays, not in blacks and whites. But there is a choice ahead of us with this bill, and that is to spend more on a dying fossil fuel economy or to invest in a growing green economy that can lift the middle class back up into prosperity, and lift those in poverty out of it. I just want to say to everybody here wearing a green shirt: I respect you and I honor you so much for all of your contributions to my future and my now. And I respect and honor you so much for being a part of this public process. And to Senator Odell, for your commitment to our health, the health of women of child bearing age and the children, I want to really respect and honor that. And we are in very uncertain times here together and it seems sometimes like we're on separate sides. And I don't think that is the case.

First off, I just want to say, I understand there's nothing more fundamental than a job. My dad, he grew up poor, in Israel. When he came to the country, the United States, he didn't even speak English. He found out that he and my mother, who had just gotten married, were pregnant, and so without any options really available, he started painting houses. And that's what he's done for my entire life, growing up. And I remember him coming home at 6, 7, 8, 9 and the smell of sweat and paint. And during the recession in the early '90s, I remember he had to work three jobs, driving a taxi, painting houses and delivering pizza. I thought it was cool that he delivered pizza, because he came home and brought the green pepper and onion for us that was left over. But I saw how hard he worked, because he believed fundamentally that every generation owes a debt to the ones coming next. And that every generation coming next has the right to a better world than the one that came before. My generation, we're a special bunch. We're the most tolerant, diverse, thoughtful, informed, connected generation in history.

We're also the biggest and most politically powerful generation in modern history. And we voted in record numbers in 2008. Through the Power Vote campaign to get young people to pledge to vote and to vote for clean and just energy sources, and not just for a party or a candidate. We got 350,000 people across the country, young people, to pledge to vote for clean energy. And we voted in record numbers, and that's because we know that our future is slipping away right now.

Every year, there's less and less that we have to rely on. My friends are struggling to pay the rent, my friends who went to school are struggling to pay for their tuition bills

Senator Martha Fuller Clark, D. 24: Excuse me, but ...

Mr. Tobey: Yes?

Senator Martha Fuller Clark, D. 24: ... it would help if you could move along.

Mr. Tobey: Yes, sorry. And in the back of our minds, we are thinking about the climate crisis. We saw what happened on TV with Hurricane Katrina. We know that that can happen more and more if we don't take drastic steps right now and we're here because we know we can do better. We can create good paying jobs in biomass and solar and wind, and energy efficiency in insulating homes. We know we can do it and it's going to take a lot of hard work and it's good work that needs to be done. But we're going to need every penny to make it happen. So every penny, every dime, every dollar, every million dollars that goes towards perpetuating the dirty energy economy of the past, that's one penny less, one dollar less, one million dollars less that we can move forward, and we don't have that time to afford.

Senator Martha Fuller Clark, D. 24: Thank you very much.

Mr. Tobey: Thank you for having me. And I just also want to say, I didn't think that there was hope at one point, when I was in high school. And it was the General Court of New Hampshire that changed my mind, because Representative Hal Melker talked to me and for those of you who know him, he was 80 years old and a real Renaissance man, and he asked me if I would go to the woods like Thoreau did, and I said, yeah, definitely. And he said no way, you're going to have to look at your grand kids in the eye every day.

Senator Martha Fuller Clark, D. 24: We very much appreciate this discussion, we appreciate the recognition of Representative Melker, but we do need to move on. Thank you.

Senator Martha Fuller Clark, D. 24: We have about 10 minutes left before recessing for lunch, so I've done my best, but I would hope that you will do your best to be quick too. Thank you.

Donald Kisharski: Madam Chair, New Hampshire Senators. I appreciate the opportunity to speak here today. My name is Donald Kisharski, I'm an instrumentation control technician at PSNH's Merrimack generating station. I live in Hooksett, New Hampshire, and my wife Alice and I have six children.

I'm here today because I'm very concerned about Senate Bill 152 and the effect it may have on my livelihood. I believe this bill threatens my job and the support that it provides for my family. The cost of raising a family in New Hampshire from food to college education is increasing at a dramatic rate. Working families like mine find it harder and harder to make ends meet. We try to scrimp and save all we can, but without a good paying job, it would be nearly impossible. It has already been determined that this clean air project at Merrimack Station is in the best interests of retail customers and the citizens of New Hampshire. The clean air benefits will be significant and the costs will be minimal to our customers, one to two dollars per month.

If you postpone this project, it will lead to higher costs, or worse, closure of our most economical and reliable source of power. Many working families such as mine will suffer if this project does not go forward. Our economy is in its worst recession in decades and it will be even more difficult for workers to find a good job if this project is halted. Our fragile economy and the wellbeing of many New Hampshire working families depends on this clean air project. Our future is at stake, so please vote on SB 152. And thank you for your consideration for the working families of New Hampshire.

Senator Martha Fuller Clark, D. 24: Thank you very much. Any questions from the Committee?

Daniel O'Neil: Good morning, Madam Chair.

Senator Martha Fuller Clark, D. 24: Good morning. Very nice to see you.

Mr. O'Neil: For the record, my name is Daniel O'Neil, I serve as an Alderman in the City of Manchester. I'm a ratepayer of PSNH and had the honor of serving in the New Hampshire State Senate, representing District 18. I'm here in opposition to Senate Bill 152.

Energy costs remain a major concern for most municipalities throughout the state, and any changes in policy that result in increased energy costs has a

Energy costs remain a major concern for most municipalities throughout the state, and any changes in policy that result in increased energy costs has a direct impact on taxpayers and municipalities' ability to provide critical services to residents. Taxpayers, taxpayer money paying for electricity is not going to go to healthcare or other social services. As you may know, Merrimack Station produces electricity at costs below open market prices. This means that this facility puts downward pressure on PSNH's customers' electric bills. Enacting public policy that establishes a path that would lead Merrimack Station out of compliance with state emission laws and could result in a shutdown of the plant would mean higher electric costs for all PSNH customers. The City of Manchester, our residents and businesses together pay approximately $122 million for electricity. If PSNH was forced to replace power produced by Merrimack Station on the open market, it could cost the City and all Manchester ratepayers an additional $5.5 million per year. While I don't have numbers for other municipalities, this same concern applies for any municipalities in the PSNH service territory. Those include Nashua, Rochester, Portsmouth, Keene and others.

Also, while it hasn't received much attention, initiating policies that could lead to the shutdown of Merrimack Station could negatively impact the future of Manchester by eliminating the possibility of bringing passenger rail service to the City. A lot of people have worked for years to move forward with this issue, but the fact is that all plans for passenger rail service depend, and I've heard Commissioner George Campbell talk about this many times, depend on active freight rail operations. Without freight trains carrying coal, lime and other materials to and from the Bow power plant, passenger rail service will not happen.

Given our current economy, we also need to give consideration to the impact of this bill on jobs. Manchester, like the state, is seeing a downturn in revenues as a result of the reduction of economic activity and employment. Considering there are current workers on site and more planning to start in the coming weeks, Merrimack Station's clean air project is truly shovel ready and your support of a bill that delays this project is the same as supporting the elimination of jobs. Truly the timing of this bill could not be worse.

It's also important to understand PSNH is a fabric of my city, as a great corporate citizen, and any efforts to undermine them hurts us. PSNH owns 85 properties in Manchester with an assessed value of $105 million, and pays the City of Manchester almost $1.6 million in property taxes. Additionally, New Hampshire DRA bills PSNH directly for the state education tax. Most importantly, the company has 322 employees who live and pay taxes in the City of Manchester, that's about, I think, a quarter of their workforce. The

scrubber project will also employ Manchester many, many Manchester residents, both in the construction trades and many of the indirect services needed to support the project.

As previously stated, I represented District 18 in the state Senate a few years ago. During my time in the Senate we made a lot of progress in the effort to reduce air emissions from power plants. People like then Governor Jeanne Shaheen, Jeb Bradley, Carl Johnson, Terie Norelli and Sylvia Larsen all provided bi-partisan leadership to ensure that we not only made progress to reduce emissions, but that we did it in a way that ensured stability and did not increase the costs of electricity for residents of the state. It would be unfortunate to see these important environmental gains delayed in a manner that could create greater risks for residents, businesses and municipalities in New Hampshire.

Just a couple quick points. Senator Letourneau mentioned construction costs. The State of New Hampshire is not immune to that. I chaired a committee here at one time when the costs of I-93 was $370 million. It's now $700 million and there's many that believe it's going to be a billion dollar project by the time it's done.

And finally, Madam Chair, you have on record a letter from Dave Preece, who's the Executive Director of the Southern New Hampshire Planning Commission, and his opposition to the bill, and Mr. Preece just asked me if I could just make sure the Committee did have that information.

Please see Attachment #4, Daniel Foley's testimony.

Senator Martha Fuller Clark, D. 24: We'll check to make sure that we have it, and we'll read it.

Mr. O'Neil: I have copies of my comments. If the Committee wishes, I can give them to you.

Senator Martha Fuller Clark, D. 24: We appreciate that so much.

Mr. O'Neil: Thank you.

Senator Martha Fuller Clark, D. 24: Are there questions for Mr. O'Neil? Thank you very much.

Mr. O'Neil: Thank you, Madam Chair.

Harold Judd: Thank you, Madam Chair, Senators. My name is Harold Judd, and I'm here to speak in opposition to this bill. I believe the bill is unnecessary and I think it's ill conceived.

By way of background. I am a Selectman in the Town of Bow, I have been for seven years, I've lived in the town for 20 years. I'm well acquainted with PSNH. I began my career as the State of New Hampshire's Consumer Advocate after serving in Washington, the Department of Energy. I returned as a Senior Assistant Attorney General and lead counsel in the PSNH bankruptcy and the Coop bankruptcy. Presently, I am a principal in a consulting firm advising regulatory entities across the nation and utilities on a number of issues, including the siting of new generation. In the past year, strike that, in the past five years, my firm has evaluated over 60,000 megawatts of new generation across this country. That's equivalent to 100 Merrimack Stations and about over 50 Seabrook stations. Units we've evaluated have ranged from nuclear power to biomass, solar, wind, coal and gas fired plants. We do no work for PSNH. The only work we do in the State of New Hampshire right now is for the State of New Hampshire regarding planning for the decommissioning of the Seabrook unit.

I urge this Committee to find this bill inexpedient to legislate for the following reasons. First, the legislation is unnecessary. The PUC will conduct a full audit and prudence review after construction is completed. This is standard procedure. I've been involved in a number of prudence reviews in the last 30 years. I've seen significant cost disallowances for waste, fraud, abuse. I have no doubt the PUC will be aggressive and do a thorough job before this expense is included in rates.

Second, if this plant project is delayed, it'll have significant impact. PSNH is mandated to have the scrubbers in place by a date certain. If they miss that date, they will be out of compliance, they will have to shut down.

Third, I firmly believe regulatory entities are entitled to regulatory certainty. The relevant provisions of RSA 125 were enacted after a process that was vetted by all parties of interest. I believe the State, if the State reneges on the regulatory compact established by that statute, it would face serious consequences. In the near term, PSNH would likely face much higher financing costs. As everyone in this room knows, access to credit is a major problem for businesses today. We should be doing nothing to make it harder for one of our major corporations. In the long term, I think that rolling back what was done in that statute will have an adverse affect on other industries and certainly on regulated companies in the state.

Fourth, if a delay results in a closing of the plant, a reliable supply of energy will be jeopardized. It is essential for utilities to have a diversified portfolio of generation. It helps in cost containment and it certainly helps for cost projections. By way of example, there's been talk here about there's cheap alternative power available in New England today. Well, if you look at the cost of gas, which is now at $4 a million BTU, in September alone it was $13. There's great volatility. These base load units bring us great certainty, they bring certainty for all businesses that rely on having that electricity, as well as for residential consumers.

Fifth, the Merrimack Station is a base load unit. It's reliable, it's dispatchable. The evolving technologies that we all expect to see in the years ahead, such as wind and solar, are not dispatchable. You can't call them up when you need them. They are part of the solution, but they are no replacement for base load units.

And sixth, PSNH is a good corporate citizen. They've been a good citizen in Bow, they're a good citizen in this state. The current management has demonstrated a recognition of the need to be responsible and accountable to the customers in the area and to the state. I believe the company entered into an agreement when they reached agreement with this body and with other interested parties in RSA 125. And I think as a matter of public policy, we should encourage that type of behavior and that we should all work together to reach our collective needs, we should respect what they did.

I urge you to find the bill inexpedient to legislate, to honor the commitment that this state made with PSNH and other stakeholders, and then to permit the PUC to complete the regulatory review and the prudence review that they will do, that they are equipped to do and that's their standard charge under the statutes.

Thank you. I have copies of my remarks that I will leave with the Committee.

Please see Attachment #5, Harold Judd's testimony.

Senator Martha Fuller Clark, D. 24: Thank you so very much. Any questions from the Committee? Mr. Lee, we have two minutes left. Can you speak in that time or would you prefer to speak after lunch?

Alexander Lee: Yeah, I can speak during that time. I have my testimony, I can just hand that to you.

Senator Martha Fuller Clark, D. 24: Thank you.

Madam Chairwoman and members of the Committee, I'm Alex Lee, I'm the Executive Director of Project Laundry List. And we take the position that it's, we have 4,000 members around the country and 400 right here in New Hampshire. Project Laundry List takes the position that it's always good to ask questions and study all options, so we support the Janeway bill.

PSNH and the building trades unions are wondering where the boots on the ground, shovels in the ground jobs would be if the plant was determined by a study not to be the best option for New Hampshire. These are good questions.

The conservation community has done this Committee and the larger business community has done this Committee, I think, a disservice so far by not providing a more comprehensive list of the "you can start tomorrow" projects that are out there. Most of the projects that do not have a big lead time are demand side management projects. There are plenty of such projects, but it's important to recognize that making the hard choices that we should have made years ago is not going to be a painless transition. There will be some jobs lost if the Bow plant closes. And there will be people who cannot help repower or upgrade the plant. There were will be some shareholders of PSNH or NU that lose money, and there will be some job retraining.

It may sound heartless, but Project Laundry List has discussed this at our board meeting and we just don't think that's the end of the world. The end of the world as we know it would be hastened. So if New Hampshire does not make the hard choices about ending our dependence on fossil fuel, how many jobs and lives will be lost if we contribute to the flooding of Bangladesh by seven feet, by running our microwaves and close dryers here in New Hampshire? The science is almost unequivocal that we need to lower the parts per million of carbon dioxide equivalents to 350 if we're to avoid a massive refugee problem from major coastal cities and populated island nations. The way to do that is to switch to wind, solar and megawatts. This is not an intellectual argument. Boots on the ground and shovels are ready. They may not be union jobs, but they are good jobs, they're good jobs.

And they're there, and you can boo. I didn't boo when you stood up, so I'd appreciate some respect. Thank you.

But Project Laundry List is prepared to offer its laundry related ideas about the way that New Hampshire businesses and residents could save millions, millions of dollars on energy costs, but this may not be the right place or time. Project Laundry List has provided these ideas to the employees of

PSNH and even issued a press release that detailed some of these laundry ideas. Nothing happened. Last week, the Concord Prison facilities manager won an award from the Governor for putting in place a cold water washing technology that's made by a New Hampshire company. Next month, I'll hopefully be presenting these ideas to the Mayor of Boston. The question is, why has PSNH done nothing to adopt these ideas? And I don't actually lay the blame with them.

I worked for the PUC in 2002 and 2003 for the Commissioners. And part of the answer is that the Commission is not able to approve new creative ideas in a streamlined fashion. Before they can approve any new ideas, they have to go through a rigorous process that involves figuring out free ridership, peak savings, measure costs, etc., etc. and so forth, a process that I assume you're all familiar with, and the kinds of things that could make even the most brilliant heads spin. Unfortunately, that is what's holding us up here from moving forward with the next generation of megawatts and green power, is that we do not have a system that allows us to approve things in a fluid way. And so I agree with Ted Gatsas on that.

Project Laundry List is wary of other energy choices this Committee or certain parties may proffer as alternatives to continued dependence on coal. Specifically, we're concerned that methane is produced by flooding new reservoirs. Hydro Quebec electricity is not a panacea. Methane released by rotting vegetation over a 20 year period has about 90 times the global warming potential of carbon dioxide over the same 20 year period. The Bush era EPA said methane was 32 times worse, but that figure was for what happens over a 100 year period. We do not have a 100 years to solve the climate program. Our comments to the Governor's Climate Commission on this topic have been ignored. The people that I spoke with at PSNH claimed to not even know that this might be a problem, if Gary Long was presented with this information as part of the Commission.

Tropical dams have been studied a little bit more with regard to this methane problem by researchers in Brazil and India, by researchers there, but the data is very thin. We need to understand this. Project Laundry List asks you not to do anything that would fast track building a high voltage wire highway from Quebec to New England unless you have answers to these concerns. Furthermore, many are beginning to wonder whether the devastating earthquakes in China are a result of the large dams there. These big issues ...

Senator Martha Fuller Clark, D. 24: Excuse me, if you could focus your remarks on the bill before us, it would be helpful. We appreciate your position.

Mr. Lee: Yeah, I'm sorry. I'll return to that and I didn't mean to get off. I think that that larger vision is really critical and you're making a decision for the next generation, here. And I'm not going to be intellectually dishonest and say that maybe the plant will have to close. Maybe it will, maybe it won't. I think it should be studied and you don't the figures that you had that some environmental groups agreed to in 2006. You don't have those figures. Things have changed, the science Cam Wake talked about has changed since 2006. The money, the economy has changed since 2006. That is a critical message. So, I'd be happy to take questions and I'm not a wilting violet, though my voice is changing.

Please see Attachment #6, Alexander Lee's testimony.

Senator Martha Fuller Clark, D. 24: Thank you, thank you so very, very much, and I will hand in your testimony. And are there any questions from the Committee? Thank you. For the others that are standing, we do need to break for lunch and we will return at 12:30 sharp. Thank you.

Hearing recessed at 12:05 p.m.

Respectfully submitted,

Catherine Mullen

Recorded by Danielle Barker,
Senate Secretary
Transcribed by Catherine Mullen,
Senate Secretary
3/20/09

6 Attachments

In This Issue:

Welcome, from your PSNH Account Executive
Time for customers to fight to maintain power rates and real customer choice!

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A Northeast Utilities Company

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FEBRUARY 12, 2009

Welcome, from your PSNH Account Executive
Time for customers to fight to maintain power rates and real customer choice!

I. Background:

An initiative is underway to stop the PSNH "Clean Air Project", and if successful, New Hampshire customers will be paying more for their energy. You can help by letting your legislator know where you stand. Read on for details."

PSNH's "Clean Air Project" is the installation of a $457 million dollar wet scrubber on the Merrimack Station coal fired power plant. **The installation is required by current State law and will significantly reduce emissions at the plant.**

Merrimack Station serves about 30% of PSNH's customer energy needs for about five (5) cents per kilowatt hour or up to one half of the volatile market price for energy in New England.The Clean Air Project will make Merrimack Station one of the cleanest coal plants in the nation, while impacting PSNH's energy service rate by an average of (0.33) cents per kilowatt hour, or about 3%.

II. At Issue

Senate bill 152 is considered by some as a way to cancel the Clean Air Project. If the project is canceled, then Merrimack Station will close.

III. Consequences of Senate Bill 152

1. If Merrimack Station closes, power currently produced by the plant will be replaced by power purchased from the New England energy market. The cost of replacement power will be higher than Merrimack Station power. Further, this replacement power, could very well come from sources less environmentally friendly than the enhanced Merrimack Station.

2. PSNH will probably sell off all of it power plants removing the choice for customers to purchase power regulated by the New Hampshire Public Utilities Commission.

3. Hundreds of jobs will be lost in New Hampshire including PSNH utility jobs, power plant maintenance contractors, construction jobs, and others.

4. Higher electric rates will have a negative impact on New Hampshire businesses and families.

5. The rail system used to transport coal will lose revenue - this could impact plans for expanded rail service in New Hampshire and New England.

III. Opposition:
An initiative is underway, by folks including Stonyfield Farms' Gary Hirshberg, the Sierra Club, Conservation Law foundation, and others to either stop or delay the Clean Air Project. Project construction is underway, any delays will add costs.

IV. Why The Opposition?

1. Cost
Certain parties question the cost of the project.

2. Possible future environmental costs and Carbon Dioxide Emissions and Global Warming
The environmental opposition is concerned universally with Carbon Dioxide (CO2) emissions from coal power plants and other sources, - and CO2's impact on "Global Warming" and "Climate Change". Further, opponents claim that new Federal environmental requirements may result in additional costs at Merrimack

Station and the project should be halted until those costs are understood.

Points taken, but lets us look at reality.

V. Reality

1. Costs

The cost of the Clean Air project will be recovered through PSNH's Energy Service charge. However, customers are not required to purchase energy from PSNH. Utility customers are encouraged to source third party suppler offerings to get the price best available!

PSNH's Energy Service Rate tends to be very competitive, and provides "real choice" for customers. Merrimack Station is key to maintaining this advantage for New Hampshire. Also, third party suppliers do not seem interested in selling energy to New Hampshire families and small businesses. PSNH is the sole provider of energy to almost one half million residential customers, and small businesses.

Speculation on future Federal environmental costs for CO2 is just that - speculation. A Federal Program will impact every fossil fuel plant in the Nation - not just Merrimack Station. Also, here regionally we have the Regional Green House Gas Initiative, (RGGI), so environmental "cap and trade" programs are nothing new.

2. Customer Needs

Customer demand for power is predictable and must be met consistently and economically to maintain our economy and way of life. We all know what life was like during the recent ice storm.

Reality is that the electric needs of all our New Hampshire factories, businesses, and homes require service by base loaded, reliable, environmentally friendly power generation. Wind, solar, biomass and other alternatives are great sources of renewable energy, but power output from these sources is small, and can be sporadic and unpredictable.

Plants like Merrimack Station are key to providing fuel diversity of our base loaded power plants. Also, plants like Merrimack Station serve as a key bridge until the day we as a society can design and build a smarter power system.

Unfortunately it will take years even decades to transform the Nation's and New England's power system to a more sustainable, and environmentally "Smart" system. Until that time we need affordable reliable clean power so New Hampshire can compete nationally and internationally.

Now is not the time to cause economic damage to New Hampshire businesses and families.

Now is not the time to cancel or delay the Clean Air Project that will make Merrimack Station one of the cleanest coal plant in the United States.

Now IS the time to contact your legislator, business group, and others to encourage the Clean Air Project to go forward.

Now IS the time for substantive rational discussions on how to best transform our power system to a "smart" system, that maintains our way of life.

If the Merrimack Station Clean Air project is canceled, New Hampshire electric rates will increase, and jobs will be lost - which is the last thing we need right now. And frankly, closing the Merrimack Station will not make a dent in the huge and complex global warming / climate change issue.

Respectfully submitted.

Craig M. Trottier.

Please Contact Your Legislators

Governor / Senate Member	Mailing Address	District	Phone	Email Address
Governor John Lynch	Office of the Governor State House, Room 208 Concord, NH 03301	State-wide	603-271-2121	
The Honorable John S. Barnes	P.O. Box 362 Raymond, NH 03077-3062	17	603-895-9352	jack.barnes@leg.state.nh.us
The Honorable Peter E. Bragdon	P.O. Box 488 Milford, NH 03055	11	603-271-2675	peter.bragdon@leg.state.nh.us
The Honorable Sharon Carson	19 Tokanel Road Londonderry, NH 03053	14	603-271-2674	sharon.carson@leg.state.nh.us
The Honorable Jacalyn Cilley	2 Oak Hil Road Barrington, NH 03825	6	603-664-5597	jacalyn.cilley@leg.state.nh.us
The Honorable Martha Fuller Clark	107 North Main Street, Room 302 Concord, NH 03301	24	603-271-4152	martha.fullerclark@leg.state.nh.us
The Honorable Lou D'Allesandro	322 St. James Avenue Manchester, NH 03102-4950	20	603-669-3494	dalas@leg.state.nh.us
The Honorable William Denley	2305 Wakefield Road Sanbornville, NH 03872	3	603-522-3802	william.denley@leg.state.nh.us
The Honorable Betsi DeVries	107 North Main Street, Room 106 Concord, NH 03301	18	603-271-6933	betsi.devries@leg.state.nh.us
The Honorable Michael Downing	7 Darryl Lane Salem, NH 03079	22	603-271-8630	michael.downing@leg.state.nh.us
The Honorable John T. Gallus	292 Prospect Street Berlin, NH 03570-2137	1	603-752-1066	john.gallus@leg.state.nh.us
The Honorable Theodore L. Gatsas	P.O. Box 6655 Manchester, NH 03104-6052	16	603-668-1233	ted.gatsas@leg.state.nh.us
The Honorable Peggy Gilmour	126 Depot Road Hollis, NH 03049	12	603-465-2336	peggy.gilmour@leg.state.nh.us
The Honorable Margaret W. Hassan	107 North Main Street, Room 302 Concord, NH 03301	23	603-772-4187	maggie.hassan@leg.state.nh.us
The Honorable Matthew Houde	P.O. Box 66 Meriden, NH 03770	5	603-504-2744	matthew.houde@leg.state.nh.us
The Honorable	225 Tyler Road			

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

April 4, 2012 - 10:07 a.m. **DAY 1**
Concord, New Hampshire ***MORNING SESSION ONLY***

NHPUC APR18'12 PM 3:40

RE: **DE 10-261**
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE:
Least Cost Integrated Resource Plan.

PRESENT: Chairman Amy L. Ignatius, Presiding
Commissioner Robert R. Scott
Commissioner Michael D. Harrington

Sandy Deno, Clerk

APPEARANCES: **Reptg. Public Service Co. of New Hampshire:**
Gerald M. Eaton, Esq.
Sarah B. Knowlton, Esq.

Reptg. TransCanada:
Douglas L. Patch, Esq. (Orr & Reno)

Reptg. Granite Ridge Energy:
Howard M. Moffett, Esq. (Orr & Reno)

Reptg. N.H. Sierra Club:
Arthur B. Cunningham, Esq.

Reptg. Conservation Law Foundation:
N. Jonathan Peress, Esq.

Court Reporter: Steven E. Patnaude, LCR No. 52

ORIGINAL

analysis in your plan?
A. (Large) I don't believe that it's accurate to say that we have not. "The Company has not produced a base case migration scenario", that is a true statement. The Company's filing includes a range of potential migration scenarios, that range from 0 percent to 40 percent. We have factored in the possibility of residential customer migration. And, those numbers are factored into that overall computation of the 40 percent migration scenario.
Q. Was migration an issue in 2010?
A. (Large) Yes.
Q. When did it first become an issue for PSNH?
A. (Large) It's been an issue in a variety of different ways since, I would say, approximately 2008. Maybe Mr. Errichetti would have a different view.
A. (Errichetti) Late 2008.
Q. Pardon?
A. (Errichetti) Late 2008.
Q. Okay. I'm going to show you a copy of a few pages from the Northeast Utilities Form 10-K for the fiscal year ended December 31st, 2010.
MR. PATCH: And, I'd like to ask that this be marked as an exhibit.

THE STATE OF NEW HAMPSHIRE

BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

PREPARED TESTIMONY OF ROBERT A. BAUMANN

INVESTIGATION INTO CUSTOMER MIGRATION AND POWER PROCUREMENT

Docket No. DE 10-160

Q. Please state your name, business address and position.

A. My name is Robert A. Baumann. My business address is 107 Selden Street, Berlin, Connecticut. I am Director, Revenue Regulation & Load Resources for Northeast Utilities Service Company (NUSCO). NUSCO provides centralized services to the Northeast Utilities (NU) operating subsidiaries, including Public Service Company of New Hampshire (PSNH), The Connecticut Light and Power Company, Yankee Gas Services Company and Western Massachusetts Electric Company.

Q. Have you previously testified before the Commission?

A. Yes. I have testified on numerous occasions before the Commission.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to address a fairness question for PSNH's customers resulting from recent rising Energy Service (ES) rates associated with increased levels of customer migration to third party supply. This testimony will describe this ES migration issue ("ES issue") and present some possible solution alternatives as to how the Commission may deal with this ES issue in future ES rate proceedings.

Q. What are you asking the Commission to address in this testimony?

A. There are two general issues that we will address in this testimony that PSNH believes should be the focus of this ES issue.

Q. What are the two general issues noted above?

A. The first issue for the Commission to address is to make a formal determination that due to increased migration, remaining customers (primarily smaller customers) taking service under the ES rate are being unfairly charged for certain ES costs. While migration is happening, customers who have switched from the ES rate to third party supply (primarily larger customers) pay nothing towards these costs until they choose to switch back to service under the ES rate. This is fundamentally unfair as it creates benefits to those customers who have migrated at the expense of customers who have not.

The second issue only arises if the Commission formally determines that due to increased migration, remaining customers under the ES rate are being unfairly charged for certain ES costs. If this is the case then the Commission would need to explore potential cost recovery options to alleviate these inequities in the ES rate. In this proceeding PSNH will offer some potential solution alternatives, but we believe it is the obligation of all interested parties to work towards reasonable solutions to this imbalance in recent ES cost recovery. The docket schedule offers ample opportunities to submit ideas on the topic and PSNH looks forward to comments and ideas from all interested parties.

Fairness Issue

Q. Please elaborate on the first issue related to the general issue of fairness where smaller customers being unfairly charged for certain ES costs.

A. To address this ES issue we need to discuss what has transpired in the past. In prior years when there was little to no customer migration, the role of the ES rate was to charge all customers an ES rate that was stable and reasonably priced. These historic ES rates offered economic stability to all customers and were supported by PSNH's generation facilities. Over the years these facilities have produced millions of dollars of benefits to customers as well as providing a stable base of generation supply that the customers could rely on. It was, and still is, PSNH's obligation and commitment to all of its customers to meet its Supplier of Last Resort obligation at all times for every hour of every day, with reliable and cost effective supply. To that end, PSNH maintains a portfolio of power sources to meet current and future load obligations. These significant power sources are PSNH's own generation and unit entitlements, IPP generation from contracts and rate orders, contracted blocks of fixed purchase power sources, and anticipated market power purchases, mostly through the daily ISO-NE interchange process. Over the past, PSNH has planned and/or procured ahead of time a large portion of the load obligation with its own generation, purchased power and IPP supplies to minimize future market exposure risk from unsecured load obligations.

Moving to the present, PSNH's ES load obligation over the past 24 months has declined significantly, due primarily to the migration of some customers (mostly larger customers) to third party supply, leaving the remaining customers (mostly residential and small

commercial) with a higher ES rate. Mathematically, as PSNH's ES load drops, the denominator in the ES rate calculation drops (sales in kWh), thus increasing the ES rate. As a partial offset, the numerator of the ES rate calculation (costs) drops due to the lower power supply requirements including avoidance of variable fuel costs, capacity purchases, etc., but not in the same proportion as the decline in the denominator. The result is that certain costs remain in both the pre and post migration ES calculations, thus resulting in upward pressure on the ES rates for the remaining customers.

Q. Please expand on the types of remaining costs that are referred to in the last answer.

A. There are certain costs that are incurred in direct support of PSNH's generation or obligated purchased power arrangements that remain fixed regardless of the level of the ES load obligation. The generation costs that are readily identifiable would be depreciation and property tax expenses as well as the debt service component of the capital structure which supports PSNH's generation. Purchased power arrangements that were entered into to minimize future market exposure risk would also have to be honored, and therefore could also be classified as fixed in nature. Arguably, the fixed portion of such purchased power arrangements could be the above market portion only.

Q. How would any identified fixed costs be handled in the context of this ES issue that PSNH has put forth in this testimony?

A. PSNH believes that at the heart of this ES issue is the fairness associated with what customers pay for these fixed costs. We believe that fixed costs that have been incurred for **all** customers should be supported by **all** customers in their rates. Therefore any identified fixed costs should not be bypassable which they now are in the current rate

Public Service Company of New Hampshire
Docket No. DE 11-250

Date Request Received: 09/16/2013 **Date of Response: 11/14/2013**
Request No. DEPOSITION-006 **Page 1 of 14**
Request from: TransCanada

Witness: Gary A. Long

Request:
Requests for reports to Gary Long on fuel markets, and/or fuel markets and their effect on generation on Merrimack Station, beginning in the summer of 2008 through the fall of 2008.

Response:
The following responsive documents from the specified time period were located.

[pls review] draft request for Gary Long purchase approval

From: Richard C. Labrecque < SUPL ENRGY SRCS > < 634-2931 > 07/31/2008 04:24 PM

To: James R. Shuckerow Jr., David A. Errichetti, Patrick P. Smith

History: This message has been replied to.

Jim & Dave - I would like to send this email to Gary asap. Please let me know if you have any concerns or comments. Pat is on-board.

Gary - at a 2009 power supply planning meeting (Apr 1st) you and Terry expressed an interest in buying a portion of our 2010 & 2011 supplemental power needs prior to the initial RGGI auction. Pat and I have spoken and both feel this is a good time to buy.

Our departmental policy requires your written authorization. We request approval to purchase 50 MWs per hour of On-Peak power for 2010 (a total of 206 GWH). Current market price is approx. $100/MWH. Total purchase expense is approx. $21M.

The attached chart details the recent history of the market for 2009, 2010 and 2010 on-peak power. For 2010, the price traded in the $85 - $95 range for most of June 2007 thru March 2008. The market peaked at $113 on July 14th and has since decreased to about $100. At least one investment bank (Goldman) has stated a belief that the natural gas market is over-sold and that certain risk factors point to a potential price increase in the coming months.

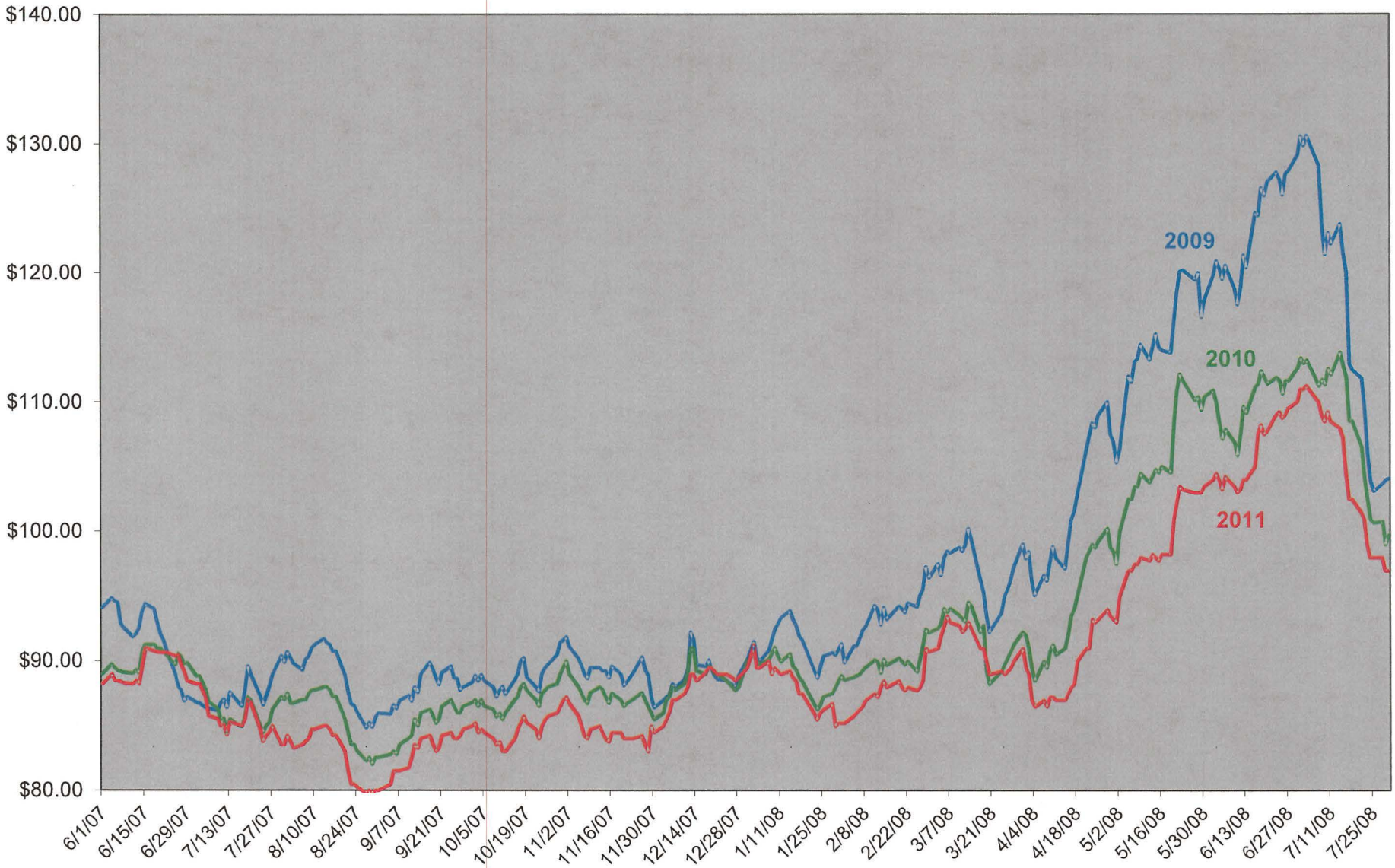
The table below is an estimate of supply resources in 2010. The requested purchase of 206 GWH would represent 2.3% of the total energy requirement.
As shown below, we anticipate a supplemental purchase need of 2928 GWH. However, over 600 GWH relates to replacement power during unplanned baseload unit outages (which we do not seek to hedge with forward purchases). Therefore, the 206 GWH represents approx. 9% of our anticipated forward power purchases for 2010.

Let us know if you have questions or would like to discuss this.

2009 2010 2011 chart.xls

	GWH	
Energy Requirement	**8867**	
Owned Assets & IPPs		
Hydro	335	4%
Coal (MK & SR)	3733	42%
NWPP	314	4%
Newington	0	0%
IPP	469	5%
	4851	55%
Existing Contracts		
VTY	168	2%
HQ Call Options	490	6%
BioEnergy Buyout	76	1%
Lempster	63	1%
Pinetree	291	3%
	1088	12%
Supplemental Purchases		
Mkt Purchases (On-Peak)	1948	22%
Mkt Purchases (Off-Peak)	980	11%
	2928	33%

Forward Price of On-Peak Power - 2009, 2010 & 2011
Jun 1, 2007 - Jul 30, 2008



date	cal09	cal10	cal11
06/01/2007	94.1	89	88.25
06/04/2007	94.85	89.75	89.00
06/05/2007	94.6	89.5	88.50
06/06/2007	94.5	89.25	88.45
06/07/2007	92.85	89.2	88.40
06/08/2007	92.55	89.1	88.30
06/11/2007	91.85	89.05	88.25
06/12/2007	92.1	89.3	88.50
06/13/2007	92.5	89.05	88.25
06/14/2007	93.8	90.55	89.50
06/15/2007	94.4	91.25	91.00
06/18/2007	94	91.25	90.75
06/19/2007	93	91	90.70
06/20/2007	92.05	90.95	90.65
06/21/2007	91.6	90.7	90.65
06/22/2007	90.85	90.45	90.65
06/25/2007	89	89.7	90.40
06/26/2007	88	90.55	90.45
06/27/2007	87.75	90.3	89.70
06/28/2007	86.9	89.8	89.20
06/29/2007	87.25	89.85	88.45
07/02/2007	86.8	88.85	88.25
07/03/2007	86.75	88.85	88.25
07/05/2007	86.4	87.85	87.25
07/06/2007	86.35	86.85	85.75
07/09/2007	86.15	86.3	85.55
07/10/2007	86.75	85.5	85.00
07/11/2007	87.05	85.55	85.05
07/12/2007	86.4	84.5	84.30
07/13/2007	87.6	85.5	85.30
07/16/2007	86.75	85	85.05
07/17/2007	86.5	84.95	85.00
07/18/2007	87.8	85.7	85.50
07/19/2007	89.6	87.2	87.00
07/20/2007	88.95	86.95	86.75
07/23/2007	87.3	85	84.75
07/24/2007	86.6	84.5	83.75
07/25/2007	87.3	85	84.25
07/26/2007	88	85.25	84.50
07/27/2007	88.95	86.25	85.00
07/30/2007	90.4	87.25	83.50
07/31/2007	89.9	87	83.50
08/01/2007	90.7	87.5	84.25
08/02/2007	90.25	86.75	83.75
08/03/2007	89.8	86.75	83.25
08/06/2007	89.3	87	83.50
08/07/2007	90.15	87	83.75
08/08/2007	90.35	87.5	84.00

08/09/2007	91	87.75	84.75
08/10/2007	91.25	87.75	84.75
08/13/2007	91.7	88	85.00
08/14/2007	91.4	88	85.00
08/15/2007	91.25	87.75	84.75
08/16/2007	90.75	87.25	84.25
08/17/2007	90.75	87.25	84.25
08/20/2007	88.95	85.5	83.00
08/21/2007	87.65	84.5	81.50
08/22/2007	86.7	83.5	80.50
08/23/2007	86.55	83.5	80.50
08/24/2007	86.05	83	80.25
08/27/2007	84.85	82.25	79.75
08/28/2007	85.25	82.5	80.00
08/29/2007	84.9	82	79.75
08/30/2007	85.65	82.5	80.00
08/31/2007	85.95	82.5	80.00
09/04/2007	85.9	82.75	80.50
09/05/2007	86.6	83	81.50
09/06/2007	86.3	82.75	81.50
09/07/2007	86.95	83.5	81.50
09/10/2007	87.35	84	81.75
09/11/2007	86.9	84.25	82.50
09/12/2007	88	85.5	83.50
09/13/2007	87.6	85	83.25
09/14/2007	89	86	84.00
09/17/2007	89.9	86.25	84.25
09/18/2007	89.35	85.75	83.50
09/19/2007	88.7	85.2	83.00
09/20/2007	88.2	85.5	83.25
09/21/2007	89.1	86.5	84.25
09/24/2007	89.6	87	84.50
09/25/2007	88.7	86.5	84.00
09/26/2007	88.65	86	84.00
09/27/2007	87.75	86	84.25
09/28/2007	88	86.5	84.75
10/01/2007	88.35	86.8	85.00
10/02/2007	88.9	87	85.25
10/03/2007	88.45	86.5	84.50
10/04/2007	88.95	87	84.75
10/05/2007	88.45	86.5	84.50
10/08/2007	88	86.25	84.00
10/09/2007	87.25	85.7	83.50
10/10/2007	87.75	85.95	83.75
10/11/2007	88.05	85.5	83.00
10/12/2007	87.45	86	83.00
10/15/2007	88.55	87	84.00
10/16/2007	89	87.25	84.75
10/17/2007	90	88	85.25
10/18/2007	90.25	88.25	85.75
10/19/2007	88.75	87.75	85.25
10/22/2007	88	87	84.75

10/23/2007	87.65	86.5	84.00
10/24/2007	89.05	87.5	85.00
10/25/2007	89.5	87.75	85.50
10/26/2007	89.75	88	85.75
10/29/2007	90.5	88.25	86.00
10/30/2007	91.45	89	86.50
10/31/2007	91.6	89.5	87.00
11/01/2007	91.85	90	87.25
11/02/2007	91.1	89	86.75
11/05/2007	90.2	88	85.75
11/06/2007	89.65	87.5	85.00
11/07/2007	89	87	84.25
11/08/2007	88.65	86.75	84.00
11/09/2007	89.5	87.55	84.75
11/12/2007	89.5	88	85.00
11/13/2007	89.25	87.8	84.50
11/14/2007	89.25	87.25	84.00
11/15/2007	88.7	86.75	83.75
11/16/2007	89.6	87.5	84.50
11/19/2007	89	87	84.50
11/20/2007	88.1	86.5	84.00
11/21/2007	88.4	86.75	84.00
11/23/2007	89.1	87.05	84.00
11/26/2007	90.3	87.55	84.25
11/27/2007	89.35	87	83.50
11/28/2007	88.9	86.45	83.00
11/29/2007	87.25	86	85.00
11/30/2007	86.4	85.5	84.50
12/03/2007	87	86	85.00
12/04/2007	87.25	87	85.50
12/05/2007	87.4	87.25	86.00
12/06/2007	88.25	88	87.00
12/07/2007	88	87.75	87.00
12/10/2007	88.6	88.25	87.50
12/11/2007	89.35	89	88.00
12/12/2007	92.25	91	89.00
12/13/2007	91.75	91	89.00
12/14/2007	89.7	89.25	88.50
12/17/2007	89.6	89	89.15
12/18/2007	90.1	89.55	89.50
12/19/2007	89.4	89.5	89.50
12/20/2007	88.9	89	89.25
12/21/2007	88.6	89	89.00
12/24/2007	88.5	88.5	89.00
12/26/2007	88.15	88	88.75
12/27/2007	88	87.75	88.50
12/28/2007	88.9	88	88.75
12/31/2007	90.2	90	89.50
01/02/2008	91.5	90.55	91.25
01/03/2008	90.25	90	89.50
01/04/2008	90	89.75	89.50
01/07/2008	90.85	90.15	90.00

01/08/2008	91.7	90.6	89.00
01/09/2008	92.45	91.05	89.50
01/10/2008	92.85	90.45	89.25
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02/20/2008	94.05	90	88.00
02/21/2008	93.75	89.75	87.75
02/22/2008	94.5	90	88.00
02/25/2008	94.2	89.2	87.75
02/26/2008	95.1	90.2	88.00
02/27/2008	95.55	91.2	88.50
02/28/2008	97.3	92.45	91.00
02/29/2008	96.45	92.2	90.75
03/03/2008	97.55	92.55	91.00
03/04/2008	96.65	92.9	92.00
03/05/2008	98.05	94.05	92.75
03/06/2008	98.5	93.8	93.50
03/07/2008	98.35	94.05	93.00
03/10/2008	98.8	93.55	92.75
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03/19/2008	93.55	89.25	90.00
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03/24/2008	93.75	89.25	89.25

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03/26/2008	95.55	90.25	89.25
03/27/2008	96.3	90.75	89.50
03/28/2008	97.25	91.25	90.00
03/31/2008	99.05	92.25	91.00
04/01/2008	97.95	92	89.50
04/02/2008	98.45	91	89.00
04/03/2008	96.25	89.5	87.00
04/04/2008	95.1	88.5	86.50
04/07/2008	96.65	90	87.00
04/08/2008	96.2	89.5	86.50
04/09/2008	97.65	90.75	87.25
04/10/2008	98.85	91.25	87.25
04/11/2008	97.95	90.5	87.00
04/14/2008	97.15	91	87.00
04/15/2008	99	92	87.50
04/16/2008	100.9	93.5	88.00
04/17/2008	101.5	94	88.25
04/18/2008	102.8	95	90.00
04/21/2008	106.3	98	91.00
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04/24/2008	108.05	98.75	93.00
04/25/2008	109	99.25	93.25
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04/29/2008	107.5	98.75	93.50
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05/01/2008	105.35	97.5	93.00
05/02/2008	106.35	100	95.00
05/05/2008	112	102.5	97.00
05/06/2008	111.55	102.5	97.00
05/07/2008	113.15	103.5	97.50
05/08/2008	113.35	103.5	97.50
05/09/2008	114.45	104.5	98.00
05/12/2008	113.25	103.8	97.75
05/13/2008	114.25	104.3	98.25
05/14/2008	115.25	104.8	98.00
05/15/2008	114.25	104.55	97.75
05/16/2008	114	105.05	98.25
05/19/2008	113.8	104.55	98.25
05/20/2008	116.3	108.35	101.00
05/21/2008	118.4	110.85	102.25
05/22/2008	120.1	112.15	103.50
05/23/2008	120.2	111.65	103.25
05/27/2008	119.45	110.15	103.00
05/28/2008	120	110.4	103.00
05/29/2008	116.55	109.4	103.00
05/30/2008	117.85	110.4	103.50
06/02/2008	119.75	110.9	104.00
06/03/2008	120.9	109.9	104.50
06/04/2008	120.35	108.4	104.00
06/05/2008	119.5	107.15	103.25

06/06/2008	120.55	107.9	104.25
06/09/2008	118.8	106.9	103.50
06/10/2008	117.55	105.9	103.00
06/11/2008	118.75	107.65	103.25
06/12/2008	121.35	109.65	104.00
06/13/2008	120.4	109.15	104.00
06/16/2008	124.65	111.15	105.00
06/17/2008	124.45	111.4	107.50
06/18/2008	126.6	112.4	108.25
06/19/2008	126	111.9	107.50
06/20/2008	127.05	111.4	107.75
06/23/2008	127.8	111.9	109.00
06/24/2008	127.25	111.65	109.25
06/25/2008	126.05	110.65	108.75
06/26/2008	127.65	111.65	109
06/27/2008	127.9	111.65	109.5
06/30/2008	129.15	112.65	110
07/01/2008	130.55	113.4	111
07/02/2008	129.85	113	111
07/03/2008	130.6	113.25	111.25
07/07/2008	128.3	111.25	110
07/08/2008	123.65	111.75	109
07/09/2008	121.4	111.35	108.5
07/10/2008	123.1	112.6	109.25
07/11/2008	122.25	112.1	108.5
07/14/2008	123.8	113.85	108
07/15/2008	121.55	112.8	107.25
07/16/2008	120	111.9	104.5
07/17/2008	112.95	108.55	102.5
07/18/2008	112.5	108.55	102.5
07/21/2008	111.85	106.6	101.5
07/22/2008	109.55	104.15	101
07/23/2008	106.1	102.5	99
07/24/2008	103.95	100.95	98
07/25/2008	103.15	100.7	98
07/28/2008	103.73	100.8	98
07/29/2008	104	99	97
07/30/2008	104.13	99.75	97

Clean Air Project
Merrimack Station

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News Release

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For Immediate Release:

PSNH Files Update on Clean Air Project

'Scrubber' Technology will Reduce Mercury and Sulfur – Maintain Source of Low-Cost Energy

Manchester, NH. September 2, 2008*****Public Service of New Hampshire (PSNH) today provided to the New Hampshire Public Utilities Commission (NHPUC) an update on the **Clean Air Project** - the installation of a significant mercury and sulfur emissions reduction system (known as "scrubber" technology) at Merrimack Station, the company's coal-fired power plant located in Bow.

"This filing demonstrates that following the installation of the scrubber, Merrimack Station will continue to be a vital base-load source for reliable and affordable power for our customers, and will have the added benefit of being among the cleanest coal-burning plants in the nation," said Gary Long, PSNH president and chief operating officer, in a cover letter which accompanied the information filed with the NHPUC.

The installation of the scrubber technology is required to comply with a new state law (RSA 125-O:11) passed in 2006, that requires PSNH capture, at a minimum, 80 percent of the mercury entering its coal-fired power boilers by July 1, 2013. Additionally, the scrubber will remove more than 30 thousand tons of sulfur dioxide emissions annually from Merrimack Station. The "Scrubber Law" is a key component of New Hampshire's first-in-the-nation four-pollutant Clean Power Act, which was passed in 2002 and governs emissions of nitrogen oxide, sulfur dioxide, mercury and carbon dioxide.

In order to expedite the process, PSNH filed the requested information in advance of the NHPUC's September 12 deadline. "It is critical that the project move forward now, in order to keep project costs down on behalf of our customers and to achieve the Legislature's requirement to reduce mercury emissions and improve air quality as soon as possible," said Long. "The Legislature and the NH Department of Environmental Services have found that the scrubber is the right technology and that its installation is in the public interest. It is vital that the project go forward without delay."

In its NHPUC filing, the company provided a project status report, response to specific economic inquiries regarding project costs and their impact on customers, and addressed a legal question regarding the NHPUC's authority relative to the project. Highlights of the information given to the NHPUC are provided below.

- more -

Jobs and Timeline – In addition to the environmental and economic benefits, the scrubber project will peak at more than 300 jobs during an approximately four-year construction period, and will complement PSNH's 100 permanent employees at Merrimack Station. Because the Clean Air Project is a vast and complex engineering and craft labor challenge, PSNH has reached a written agreement with the building trades leadership to only use union labor on this project to ensure the availability of highly productive and skilled craft workers and to prioritize safety, above all, on the job.

Project Cost and Customer Impact – PSNH's current Energy Charge of 9.57 cents per kilowatt hour (kWh) is the lowest of any utility in New England. The Clean Air Project cost of $457 million will add an average of 0.31 cents/kWh (three tenths of one cent) to that charge. The PSNH Energy Charge is set by the NHPUC, based on the actual cost of PSNH producing or purchasing the energy it needs to meet customer demand. Other utilities base their respective energy charges on the 'market price' because they do not own their own power generation facilities.

"The cost of coal is economic and relatively stable, compared to oil and natural gas, the commodities which set the New England market price," noted Long. "The Clean Air Project will ensure that we maintain a reliable and economic source of energy at Merrimack Station, which will continue to provide fuel diversity for New England."

The project budget has been based on a schedule aimed at beginning operations one year earlier than required, by mid-2012. Current work includes: detailed engineering, under the direction of the project program manager, Washington Division, URS Corp.; preliminary site preparation; and permitting. Major construction is scheduled to begin in 2009.

Legislative Mandate and NHPUC Authority – The NH Legislature in 2006 mandated the scrubber project, finding that "The installation of such technology is in the public interest of the citizens of New Hampshire…" and that it "…represent(s) a careful, thoughtful balancing of cost, benefits, and technological feasibility…" (RSA 125-O:11).

PSNH included a Memorandum of Law in its filing, at the request of the NHPUC, as the commission considers what authority it has relative to the project. The company provided a detailed breakdown of the law's intent and requirements and concluded that the commission's authority regarding the project is limited to determining the recovery of prudent costs once the project is completed.

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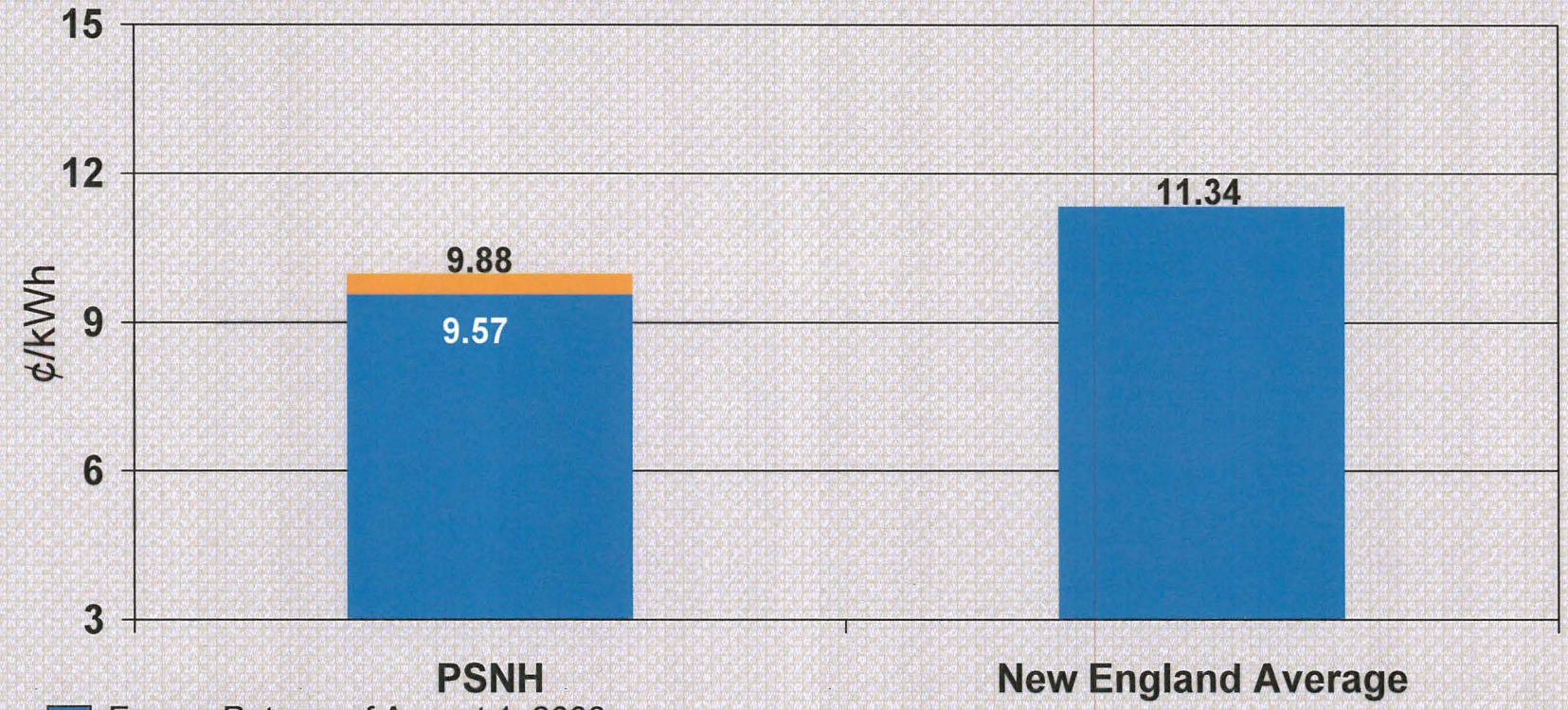
PSNH is New Hampshire's largest electric utility, serving more than 490,000 homes and businesses.

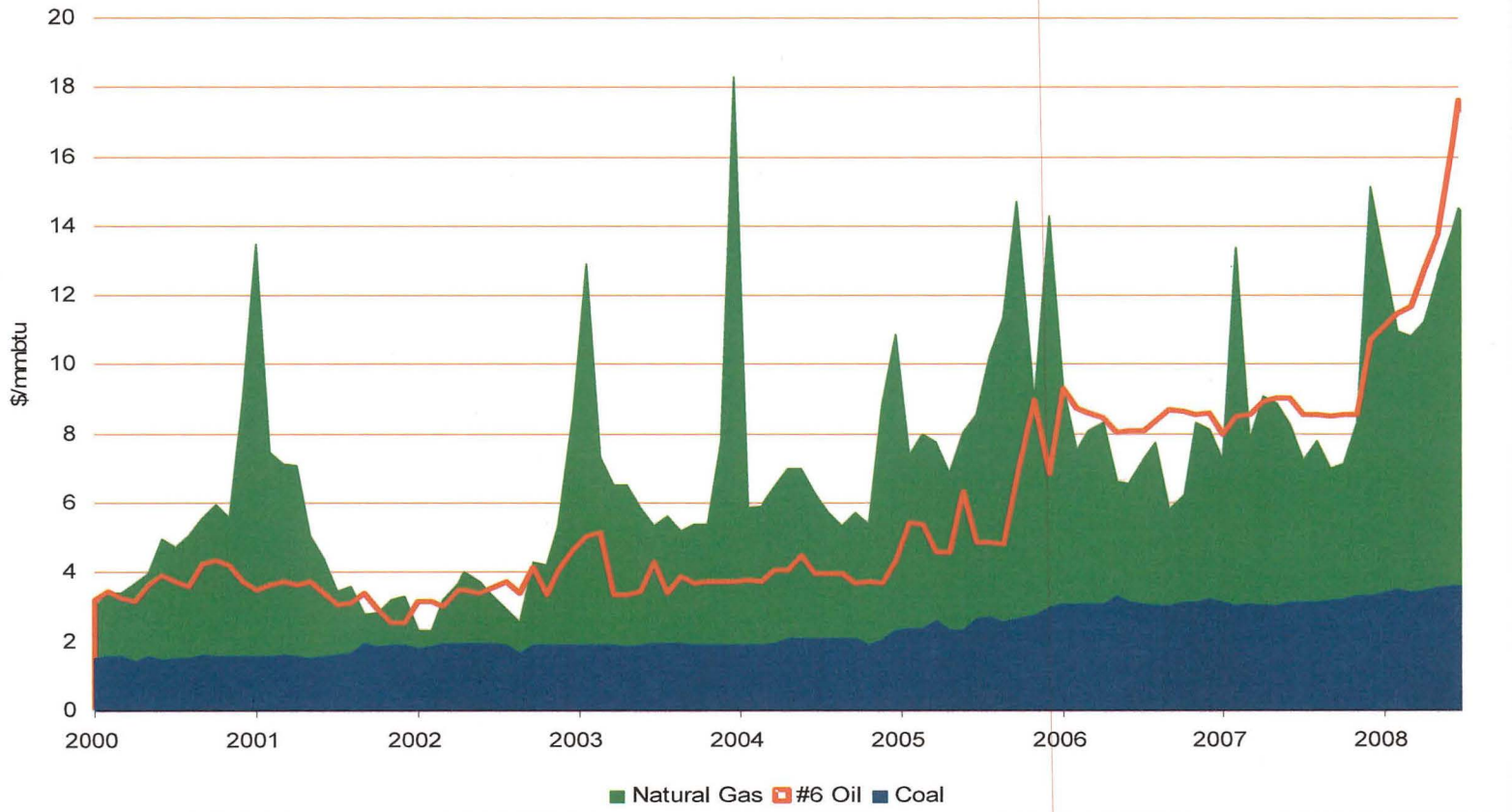
PSNH Expects Its Energy Rate to Remain Lower Than the New England Average Even After the Clean Air Project is Completed

Upon completion, the Clean Air Project will add on average about 3/10's of one cent to PSNH's Energy Charge.



9/2/08

Coal has Proven to be Among the Most Stable and Cost Efficient of All Fuels



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