STAFF - EX. ~~7~~ 6

Economic Assessment of NSTAR's Third 345 kV Transmission Line from Carver to Cape Cod

Prepared for

NSTAR Electric Company

Westwood, MA

June 1, 2010

LEVITAN & ASSOCIATES, INC.
100 Summer Street, Suite 3200
Boston, Massachusetts 02110
Tel 617-531-2818
Fax 617-531-2826

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GLOSSARY

AFRR	Annual Fixed Revenue Requirements
AFUDC	Allocation of Funds Used During Construction
APR	Alternative Price Rule
BART	Best Available Retrofit Technology
BEII	Bridgeport Energy II
BTA	Best Technology Available
Btu	British Thermal Unit
CAIR	Clean Air Interstate Rule
CC	Capacity Cost
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CWA	Clean Water Act
DAM	Day-Ahead Market
DBD	Design Basis Document
DPUC	Department of Public Utility Control
DR	Demand Response
DRR	Demand Response Reserves
EDC	Electric Distribution Company
EE	Energy Efficiency
EG	Emergency Generation
EPA	Environmental Protection Agency
EUA	Eastern Utilities
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FCMWG	Forward CM Working Group
FERC	Federal Energy Regulatory Commission
GT	Gas turbine
GWh	Gigawatt Hour
Hg	Mercury
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
IESO	Independent Electricity System Operator
IMMU	Internal Market Monitoring Unit
IRP	Integrated resource plan
ISO-NE	Independent System Operator-New England
kV	Kilovolt
LAI	Levitan & Associates, Inc.
LFRM	Locational Forward Reserve Market
LSR	Local Sourcing Requirement
MMBtu	Million British Thermal Units
MTM	Mark-to-Market
MW	Megawatt
NCPC	Net Commitment Period Compensation
NEPOOL	New England Power Pool
NML	Normal Minimum Load
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NSTAR	NSTAR Electric Company
O&M	Operation and Maintenance
OOM	Out-of-Market
PILOT	Payment In Lieu Of Taxes
PM	Particulate Matter
PSEG	Public Service Electric and Gas
PTF	Pool Transmission Facilities
PV	Present Value
RFO	Residual Fuel Oil
RMR	Reliability-Must-Run

RMRe	Reliability-Must-Run equivalent
ROI	Return on Investment
ROS	Rest of System
RPS	Renewable Portfolio Standard
RSP	Regional System Plan
RT	Real Time
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SEMA	Southeastern Massachusetts
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
TMOR	Thirty Minute Operating Reserves
TWh	1000 GWh
VAR	Volt-Ampere Reactive

1 INTRODUCTION

NSTAR Electric (NSTAR) is proposing to construct a 345 kV transmission line in the Southeast Massachusetts (SEMA) Load Zone between the Town of Carver and Cape Cod (the Project). The Project's commercialization would substantially increase the transmission import capability to the portion of the Lower Southeastern Massachusetts (LSM) load center that NSTAR generally refers to as "Tremont East." Tremont East consists of Cape Cod and the Islands, as well as the mainland area as far north as the Tremont substation located in Wareham.

Existing transmission into Tremont East consists of two 115 kV lines and two 345 kV lines. The largest generator in the affected area is Mirant's Canal generating plant (Canal). Canal is a dual-unit 1,095 MW (combined summer capacity) steam turbine generating (STG) plant located in Sandwich, MA. According to ISO-NE, one Canal unit is committed out of economic merit order for approximately 42-58 days per year to maintain reserve requirements.[1] The Project's additional transmission capacity will eliminate the need to operate Canal to meet bulk power security objectives in LSM.

Levitan & Associates, Inc. (LAI) was engaged by NSTAR to evaluate the economic and environmental benefits ascribable to the Project. Part of LAI's scope of work has therefore included an objective and independent assessment of Canal's financial position over the relevant planning horizon. For purposes of this study, we have defined the planning horizon to be ten years, *i.e.*, 2013 through 2022. LAI has assessed the economics of meeting Tremont East's reliability requirements (a) without the Project and with Canal's continued operation over the planning horizon, and (b) with the Project but with Canal retired. In addition to comparing the Project to ISO-NE's continued reliance on Canal, LAI also compared the Project to the most practical alternative solutions: first, quick start peaking generation; and second, expanded demand response (DR).

[1] ISO-NE SEMA Long-Term Report Executive Summary at 4, dated January 20, 2009. See http://www.iso-ne.com/pubs/spcl_rpts/2009/executive_summary_sema_long_term_report.pdf

2 EXECUTIVE SUMMARY

Reliability in the Tremont East load subzone has historically been furnished by the dual-unit, 1,095 MW Canal Station. Both units are very old STGs, with vintage dates of 1968 and 1976. The units take a long time to start up, ramp poorly, and cannot be committed in real time. Unit 1 was originally designed for baseload, while Unit 2 was originally designed as a load-following intermediate unit. While Unit 1 burns only RFO, Unit 2 can burn RFO and/or natural gas.

Canal's capacity factor averaged about 50% from 1999 through 2005. Since then, it has plummeted to below 20% in 2006 through 2008. During this period, the majority of Canal's generation was out-of-merit-order, at significant ratepayer cost. In 2008, Canal collected either all or the lion's share of ISO-NE's second contingency uplift payments of $143.4 million in SEMA. These costs have diminished since NSTAR completed its short-term transmission improvements in 2009. Canal was dispatched sparingly in the Day-Ahead Market (DAM), and its capacity factor in 2009 was below 6%.[2] Going forward, LAI forecasts that Canal Unit 2 will continue to operate at a low capacity factor, averaging about 3% in the summer for 2013 through 2022. The capacity factor for Unit 1 is and will continue to be virtually nil. We do not expect either unit to operate at all during the winter. Despite Canal's extremely low capacity factor over the planning horizon, *absent the Project* Canal will be required by ISO-NE to provide second contingency coverage for Tremont East.

For financial support, Canal depends on the Forward Capacity Market (FCM) administered by ISO-NE. Since the first Forward Capacity Auction (FCA), the FCM has cleared at the floor price, and these revenues are further reduced by pro rationing to reflect the surplus of cleared resources. The generation surplus in New England, the entry of renewables and DR, and the recessionary effects on load portend a continuation of the FCM clearing prices at the floor value through 2016. Over the next several years, Canal's financial challenges will be exacerbated by more stringent environmental restrictions, increasing its costs and requiring significant new capital investment. Specifically, we expect that Canal will need to either retrofit its cooling water intake structures with new screens or similar modifications, or it will be required to convert its once-through cooling water system with a capital-intensive, closed loop system and cooling towers.

Using a conservative estimation of Canal's fixed operation and maintenance (O&M) expenses to maintain plant availability, LAI expects that Canal will operate at a significant financial loss over the planning horizon. If we assume the need for minimal environmental upgrades, the present value of the cash operating loss is estimated to be $68 million. If we assume the need for more extensive upgrades, the present value of the cash operating loss is estimated to be $184 million.

[2] Based upon NSTAR meter data.

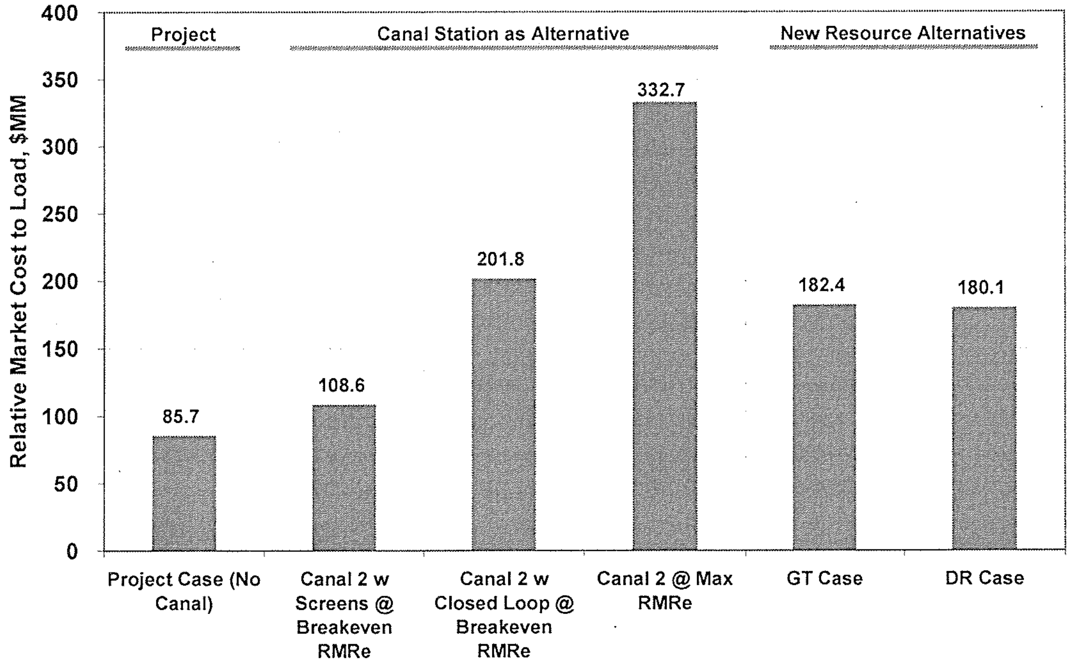
Recognizing the units' poor financial performance, Canal could decide to submit a de-list bid. In our opinion, ISO-NE would accept the de-list bid for one unit (and thereby allow one unit to retire), but reject the de-list bid for the second unit needed for reliability, thereby providing Canal with much higher capacity prices than would otherwise be realized as a price taker in the FCM. A rejected de-list bid is equivalent to the formerly negotiated Reliability-Must-Run (RMR) agreements. Hence, throughout this report we refer to above-market compensation achieved through the de-list bid process as equivalent to RMR contracts, or "RMRe" for short.

Under the de-list bid protocol approved by the Federal Energy Regulatory Commission (FERC), a Canal de-list bid would cover Canal's out-of-pocket cash costs and could also include opportunity costs, including both the return of and on capital for any incremental investment to ensure environmental compliance. We estimate that a rejected de-list bid for Canal would result in RMRe payments of between \$43 million and \$99 million in 2016, depending on environmental requirements and Mirant's de-list bid strategy. Under RMRe, Canal would be entitled to enjoy above-market payments until such time that ISO-NE determines that Canal is no longer needed for reliability.

To meet the reliability criterion for Tremont East, the Project, Canal, or a new, alternative resource is required. We have added up the costs and benefits for a variety of options, summarized in present value form in Figure 1. LAI believes the key comparison here is between the first bar (the Project) and the second bar, with Canal receiving RMRe payments at a breakeven level, assuming retrofit of water intake screens to meet environmental requirements. This alternative would result in present value costs to load \$22.9 million higher than those of the Project. Note that, if Mirant were forced to convert to closed-loop cooling, the incremental cost would escalate to \$116.1 million, and if Mirant is able to maximize RMRe revenues over the study period, the cost to load could be as much as \$247 million above that of the Project.

In reviewing the financial results, three caveats bear brief mention. First, by Project economics we mean net cost to load, that is, the net change in the total cost to serve load when we compare a case with the Project in service against either a reference case without the Project or against an alternative to the Project. Second, Project economics herein are on a region-wide basis. Third, Canal's decision to retire or submit a de-list bid for one or both units may be affected by other commercial and practical considerations associated with the cost of decommissioning the plant, salvage value, employment, and community relations.

Figure 1. Present Value Cost – Project v. Alternatives



LAI also evaluated the emission displacement potential offered by the Project in comparison to continued reliance on the Canal units. Over the ten-year study period, we estimate that avoided particulate matter (PM) on a local basis would reach up to 5 tons per year. Avoided nitrogen oxides (NOx) and avoided sulfur dioxide (SO_2) would each reach up to about 100 tons per year early in the study period. Avoided carbon dioxide (CO_2) emissions are not relevant on a local basis, since CO_2 has global impacts, but Canal operating on RFO currently emits approximately 0.92 tons per MWh. Note that for this study, we have assumed Canal Unit 2 is burning natural gas to comply with environmental regulations. This analysis is covered in more detail in Section 4.2.2.

LAI also compared the Project's economics to other resource options that have the potential to satisfy the reliability requirement for Tremont East. Two alternative options were tested: first, new quick-start gas turbine (GT) generation located at or near the Canal site; and second, an enhanced DR program in Tremont East. The GT option consists of two GE Frame 7FA units amounting to 314 MW – enough incremental capacity to meet the reliability requirement over the study period. With respect to an enhanced DR program in Tremont East, only 30-minute real time DR and real time emergency generation (EG) are technically capable of providing operating reserves for second contingency. Both the quick start GT and the sub-category of DR considered by LAI would qualify for second contingency coverage so long as the technology of choice can be activated within 30 minutes. Relative to the Project, as shown in Figure 1, both quick start generation and new DR demonstrate comparatively poor economics over the study period. Relative to the Project, the GT option is deep-in-the-red, $96.7 million more expensive to load than the Project. The enhanced DR option is also deep-in-the-red, $94.4 million more expensive to load than the Project.

In gauging the potential (de)merit of alternative resources, we note the following: first, a new quick start unit designed to provide reliability benefits in Tremont East would require a power purchase agreement (PPA) with NSTAR to ensure orderly pass through of all fixed and variable costs; second, while several classes of DR can participate in the FCM, for environmental reasons ISO-NE limits the total system-wide quantity of EG, thus requiring enhanced DR in Tremont East to be interruptible load, *i.e.*, subject to 30-minute interruption; and, third, the underlying penetration rate of interruptible load DR in Tremont East that would be needed to provide the requisite capacity for the second contingency event is not realistic and not likely to be attainable.

There is an explicit need for a solution in the Tremont East area. The historical answer, operation of Canal, has been a cost problem for ratepayers, and we believe Canal is in a financially unsustainable position. This position will continue to deteriorate as additional capital investments are required to comply with environmental regulations. Among the alternatives available, the Project as proposed by NSTAR offers the most effective, least-cost solution for ratepayers.

3 METHOD AND APPROACH

3.1 Energy Market Model

LAI evaluated the expected dispatch of resources in Tremont East and across New England over a ten-year planning horizon, 2013 through 2022. Each 12-month period corresponds to the ISO-NE capacity year, *i.e.*, capacity year 2013 is June 1, 2013 through May 31, 2014. Capacity year 2013 was selected as the first year in the planning horizon because it corresponds to the Project's anticipated in-service date. In order to evaluate the economics of the Project, LAI conducted production simulation analysis of the wholesale power market throughout New England, including transmission interchange between New England and neighboring market areas. Emphasis was placed on the resource and planning criteria of relevance in SEMA and Tremont East. To conduct this analysis we used the MarketSym/ProSym Chronological Production Simulation System (MarketSym), a production cost modeling system licensed by Ventyx, an Atlanta-based software company.

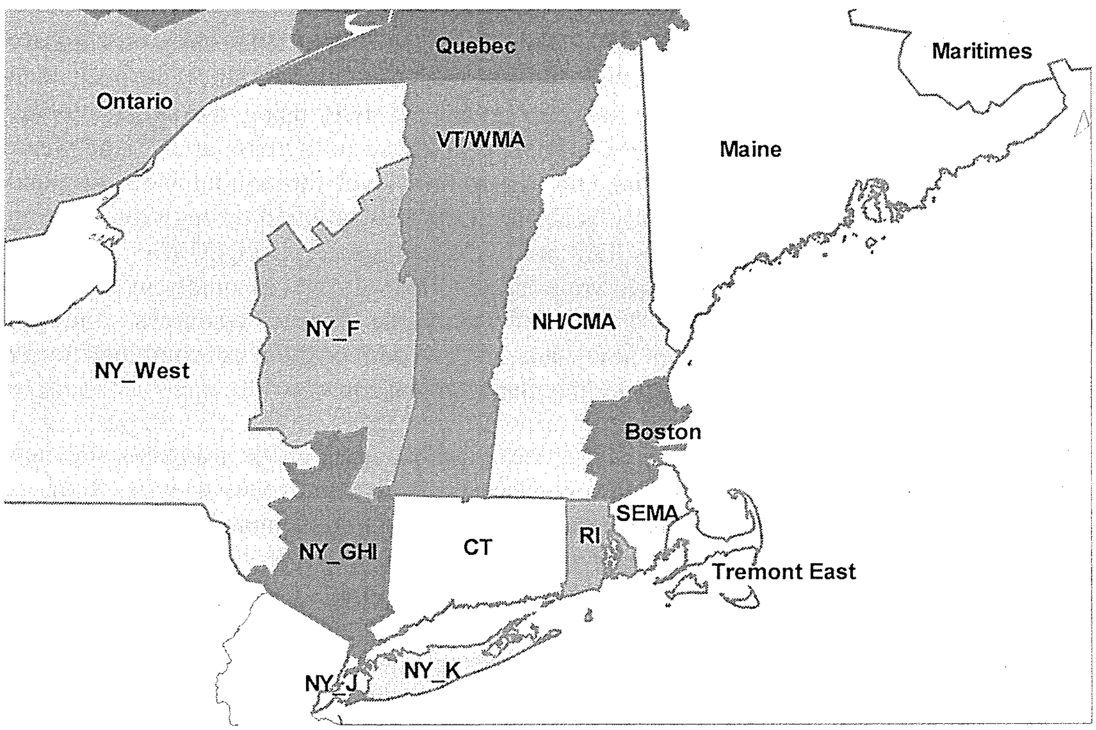
MarketSym is an industry-leading software platform that simulates electricity production by individual generating units and power flows across transmission zones and sub-areas. Transmission interface limits are accounted for in all model solutions. Using hourly conventions, MarketSym has the capability to forecast the dispatch of individual generating units, locational energy prices, variable production costs, and plant emissions. While the initial database is licensed from Ventyx, LAI has incorporated a number of adjustments in order to more finely calibrate model solutions to the actual or reasonably expected market, operating, and regulatory conditions affecting the scheduling of New England's power plants over the planning horizon.

The market simulation database contains generator, fuel, load, emissions, and transmission data. This database, coupled with MarketSym's plant scheduling logic that optimizes wholesale power costs on a regional basis, are the foundation of the wholesale energy price forecast performed in this study. The impact of energy efficiency (EE) and DR is incorporated in the forecast. The database stores detailed generator information at the station level that includes start-up and shut-down costs, total and marginal fuel costs, heat rates, ramp rates, non-fuel variable operating expenses, emission rates and allowance costs. Detailed load and transmission interface data for each of the control areas of interest is also incorporated in the database.

To ensure model validity, LAI regularly updates the database with information obtained from documents published by ISO-NE as well as other independent system operators in the region, including Canada. Published data of primary relevance include ISO-NE's 2009 Regional System Plan (RSP09), the results of ISO-NE's FCAs, transmission expansion plans, resource adequacy studies, and other regulatory filings. NOx emission rates are based on the Environmental Protection Agency (EPA) Clean Air Markets database; SO_2 and CO_2 emissions are based on fuel type and plant characteristics. LAI also relies on other reports published by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

For this study, LAI modeled the transmission interfaces among the relevant load zones across ISO-NE using the values for the transmission limits from RSP09. In order to evaluate the Project, Tremont East has been treated as a separate load zone within SEMA. Absent the Project, the interface limit between Tremont East and the remainder of SEMA has been estimated to be greater than 1,500 MW. To simplify the analysis by avoiding unnecessary computation time, certain zones within ISO-NE have been combined where transmission constraints are not likely to impact the Tremont East results. To account for exports and imports and transmission flows with neighboring control areas, LAI also modeled the New York, Ontario, the Maritimes, and Hydro Quebec control areas, as shown in Figure 2.

Figure 2. MarketSym Topology



Load data in MarketSym are derived from the publications listed in Table 1. We utilize the 50/50 forecast from each publication. To maintain consistency over the planning horizon we have extrapolated the data as necessary through 2022. In addition, we assume that enhanced EE measures through states' initiatives and incentives (not participating in the FCM) will reduce load across New England by an additional 4%.[3] Similar programs and load reductions are assumed in NYISO.

[3] The 4% enhanced EE does not apply to the Tremont East base line load forecast, which already incorporates NSTAR's EE initiatives.

Table 1. Sources of ISO Load Data

ISO-NE	2009 Capacity, Energy, Load, and Transmission Forecast[4]	2009-18
NYISO	2009 Load and Capacity Data Report	2009-19
Quebec	Forecast of requirements and sales in Québec, July 2009	2009-18
Maritimes	2008 Maritimes Area Interim Review Of Resource Adequacy	2009-12
Ontario	IESO 2009 Comprehensive Review of Resource Adequacy	2010-14

Generation resources across ISO-NE in the simulation model are based on the generation and DR capacity obligations arising from the first three ISO-NE FCAs, *i.e.*, FCA#1-3. LAI developed a capacity expansion plan by contemplating the addition of new renewables and then DR as needed to meet the installed capacity requirement (ICR) for each control area over the study horizon. Between capacity year 2014 through capacity year 2018, the ICR in RSP09 grows from 10.6% to 11.3% above the 50/50 peak load forecast. After capacity year 2018, we extrapolate the ICR using the same average growth rate as the 50/50 peak load forecast. DR is assumed to increase at 2.7% per year, reflecting a small real increase in the DR penetration level throughout New England relative to load growth. Over the study horizon, the ICR is satisfied through the existing generation resources, new renewables, DR and EE. Due to the existing MW overhang in New England, the reduction in load growth relative to load growth assumptions that were prevalent several years ago, the growth of renewable energy resources, and the availability of incremental DR, no new generic gas-fired peakers or combined cycle plants are added to the resource mix over the planning horizon.

The entry of renewable resources reflects the aggregate renewable portfolio standard (RPS) requirements of the individual Northeast states, the relative proportion of renewable technologies in each ISO's interconnection queue, estimated capacity factors by technology type, and wind resources by zone. By 2020, we project a total of 2,615 MW of wind resources and 759 MW of biomass and landfill gas resources in New England. These nameplates are stated on an installed capacity (ICAP) basis. The new wind capacity postulated to meet the RPS includes an off-shore wind project in Tremont East. Off-shore wind entry in Tremont East is assumed to step-up from 50 MW in 2013 to 450 MW by 2017. No effort has been made in this study to reconcile the step-up of off-shore wind in Tremont East with Cape Wind's proposed development schedule.

The 2010 Integrated Resource Plan (IRP) published in early January, 2010, by Connecticut's electric distribution companies (EDCs) includes an attrition analysis and a capacity price forecast. We considered Connecticut's IRP in evaluating generator entry / exit effects over the study horizon. Connecticut's IRP identified the RFO-fired STGs as the plants most vulnerable in New England to retire. The reason the RFO units are most likely to retire is because they typically have very low energy revenues, virtually no profit margin from energy sales when operating in-merit, and, most importantly, exposure

[4] http://www.iso-ne.com/trans/celt/fsct_detail/2009/isone_09_forecast_data_rv5.xls

to costly new environmental requirements in the near term when Clean Interstate Air Rules (CAIR) are promulgated by EPA. The IRP concluded that 825 MW of STGs across New England would retire in 2013, and another 1,621 MW in 2016. We agree that these are the type units in New England that are the most prominent candidates for retirement or mothballing; however, LAI believes that some of these plants are likely to remain in commercial operation by adopting different environmental compliance strategies than those assumed by the Connecticut EDCs in the 2010 IRP. Furthermore, the Connecticut IRP was performed before additional information regarding de-list bids became available through the FCA#4 filings.

In conducting this analysis, LAI has assumed the following retirements:

- Somerset Unit 6 (100 MW), a coal unit in SEMA, is retired at the start of the modeling period. Somerset's static de-list bids for FCA#1-3 have been accepted. Somerset has no capacity obligation from June 1, 2010 through May 31, 2013.[5]
- Norwalk Harbor 1 and 2, Yarmouth 1 and 2, and Bridgeport Harbor 2 in capacity year 2014, about 563 MW.
- Yarmouth 3 and 4, Cleary 8, West Springfield, Middletown 3 and 4, and Montville 6 in capacity year 2016, about 1,882 MW.

Because the analysis is centered in Tremont East, the modeling results are not overly sensitive to the location of the retirements in New England. Instead, the financial results are sensitive to overall quantity of capacity that is retired. The greater the amount of retirements, the higher the resultant capacity prices, and *vice versa*. In order to test Canal's economics more conservatively, the decision was made to potentially overstate the amount and timing of generator plant retirements. The actual amount of generator retirement may be materially different, *i.e.*, lower, further diminishing Canal's financial outlook.

3.2 Capacity Market Model

LAI developed a capacity price model which simulates the functionality of ISO-NE's FCM. LAI's capacity price model calculates FCM clearing prices based on forecasted load, ICR, the capacity expansion plan and retirements described in Section 3.1, and other relevant factors. The FCM model also reflects the market rule changes proposed by the FCM Working Group (FCMWG), adopted by the NEPOOL Participants Committee on November 6, 2009, and jointly filed with the FERC by ISO-NE and NEPOOL on February 22, 2010. Those recommendations were outlined in the FCMWG Design Basis Document (DBD) dated November 5, 2009, including a rule change filed at FERC by ISO-NE in February 2010.

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[5] Although NRG has proposed to convert the plant to a plasma gasification technology, the project has encountered permitting obstacles and we know of no EDC or state regulatory initiative to provide credit support to anchor the conversion.

LAI has assumed that the rule changes filed at FERC will be approved by FERC without revision. Highlights of the proposed rule changes include the following:

- Redesign of the Alternative Price Rule (APR), which is designed to protect the market from exercise of monopsony power in the form of the entry of new "uneconomic" or Out-of-Market (OOM) resources.
- The extension of the price floor and the price ceiling through capacity year 2015.
- Change in the method used to calculate Cost of New Entry (CONE).
- Extension of the price guarantee period for new entrants that clear the market.
- Modeling of capacity zones to generally match energy zones.
- Change in the method used to determine local capacity requirements.
- Treatment of DR.

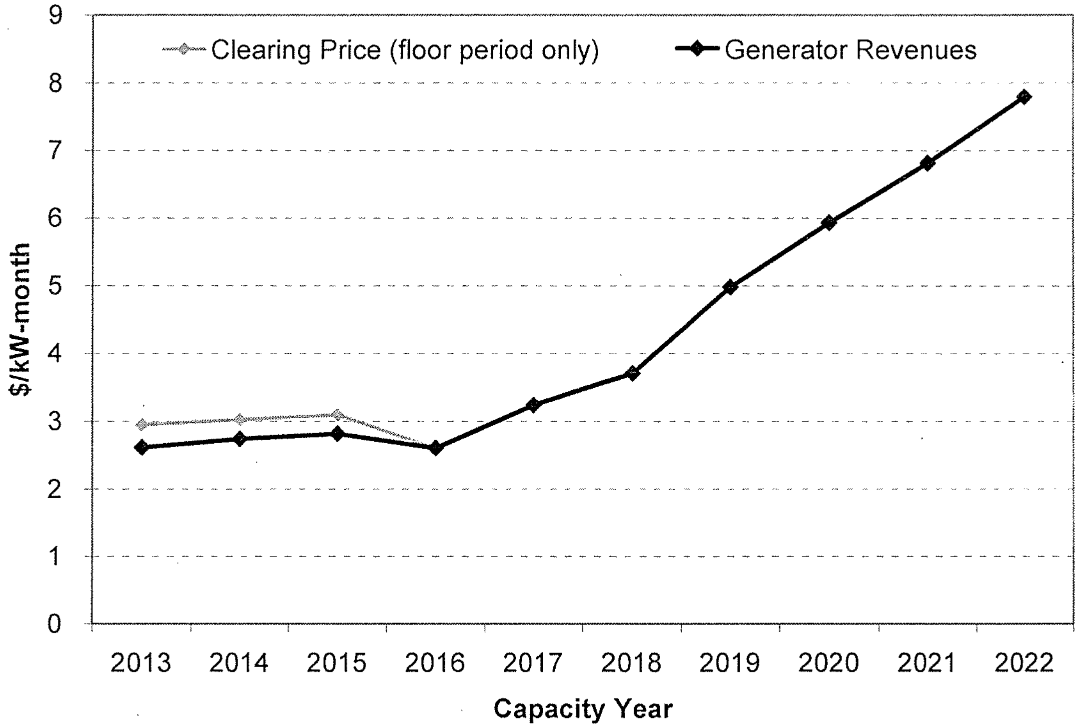
LAI's model forecasts the clearing prices under the FCA and the actual payments to qualified resources throughout the region to account for pro-rationing effects. When the FCM clears at the floor, payments to generators are reduced to account for the surplus in eligible resources.[6]

The modified APR has a number of mechanisms that can impact market outcomes. One pertains to the entry of OOM resources. The other pertains to the filing of de-list bids from existing resources that are needed for reliability. Over the planning horizon we have assumed no OOM entry and therefore no triggering of the APR. In addressing Canal's financial results, we have assessed Canal's ability to realize above-market capacity revenues under ISO-NE's de-list bid procedures since – absent the Project -- Canal is needed for reliability in Tremont East. In Section 5.2.2, LAI discusses the existing ISO-NE rules regarding de-list bids.

The FCM model utilizes a supply curve developed from the bid data from FCA#3, the most recent auction. ISO-NE's FERC filing regarding the FCA contains a round-by-round summary of the amount of capacity still willing to participate in the market at each "tick" of the auction clock. These price-quantity pairs form an upward sloping supply curve that is used to forecast clearing prices. Prices increase over time as the market tightens due to load growth and the retirements discussed in the previous section. Our forecast of FCM clearing prices and generator payments is shown in Figure 3. As noted above, generators receive payments that are pro-rated and therefore less than the floor price for the first three years of the forecast, after which the floor is removed.

[6] The payment is prorated based on the magnitude of the capacity excess. If, say, the FCA clears at the floor price and there is 5% excess capacity beyond the target, then generators would receive a payment equal to 95.2% of the floor price, or 100%/105%.

Figure 3. Capacity Price Forecast



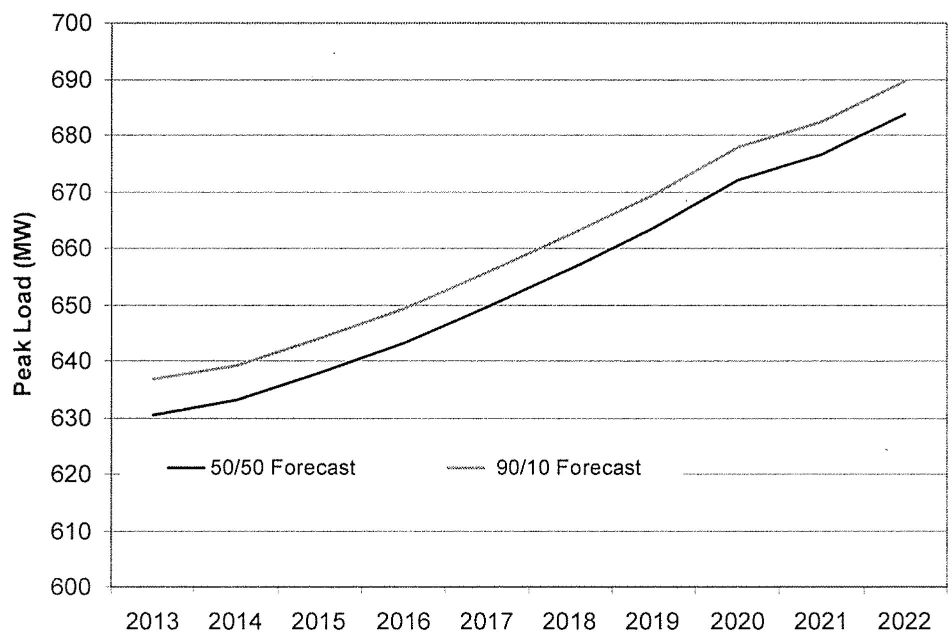
4 SUMMARY OF CURRENT CONDITIONS

4.1 Tremont East Load and Resources

NSTAR's peak load forecast for Tremont East is shown in Figure 4. The load growth reflects NSTAR's continued investments in additional EE. The uncertainty in the long-term peak load forecast is reflected by the different probability levels shown in this chart. The expected values are represented by the 50/50 forecast; that is, in any given year there is a 50% probability that the actual load will be higher or lower. Over the long term, the 50/50 forecast provides the best estimate of the peak load and costs associated with serving that load over the forecast horizon. LAI used the 50/50 forecast in our MarketSym model to evaluate unit commitments, production costs, and energy prices.

The 90/10 forecast represents a higher probability forecast; that is, in any given year there is a 90% probability that the actual peak load will be less than the forecast and only a 10% chance that the actual peak load will be higher than the forecast. The 90/10 load is commonly used by grid operators such as ISO-NE, and is appropriate for resource planning purposes. LAI used the 90/10 forecast to assess the installed capacity requirement for Tremont East, as discussed in Section 7.1.1.

Figure 4. Tremont East Peak Load Forecast



In addition to the 1,095 MW Canal Station, other resources in Tremont East are very small, *e.g.*, 13.7 MW on Martha's Vineyard and 6 MW on Nantucket.[7] Information provided by NSTAR identified 7.4 MW of active real-time DR in Tremont East capable of being activated within 30 minutes. Over the forecast period, we assume that the DR in Tremont East grows at the same rate as the rest of the system, 2.7% annually. Across all cases we have incorporated off-shore wind in Tremont East. By 2017, the total off-shore wind nameplate amounts to 450 MW.[8]

4.2 Canal Station Operations

4.2.1 Current Operating Conditions

Canal Station consists of two STGs. Unit 1 was placed in service in 1968 and has a summer rated capacity of 550 MW. Unit 2 entered service in 1976 and has a summer rated capacity of 545 MW. Unit 1 operates only on RFO. Unit 2 was converted to natural gas in the early 1990s and is dual-fuel capable. While Unit 2 is capable of burning natural gas and/or RFO, Unit 2 has typically operated on RFO only. Unit 1 was designed to operate as a baseload plant. Unit 2 was designed with more operational flexibility for load-following. As baseload and intermediate units, the Canal units have start-up times of 20 and 24 hours. Additional time is then required for the units to ramp to the necessary output level once synchronized with system load.[9]

In carrying out its reliability responsibilities for each operating day, ISO-NE analyzes the results of the DAM, in which energy supply offers and demand bids are cleared using a Security Constrained Unit Commitment algorithm. After the DAM closes, ISO-NE performs a Reserve Adequacy Analysis that considers whether out-of-merit commitment of additional generating units is required in order to ensure reliability during the upcoming operating day. Units so committed are "flagged" in ISO software based on the reason(s) for which they are committed. These flags permit the ISO's settlement staff to undertake Net Commitment Period Compensation (NCPC) calculations for each unit. More colloquially, these NCPC payments to individual units needed to meet local reliability requirements are referred to as "uplift." Among other reasons, NCPC is paid to a unit that is committed out-of-merit to provide coverage for a second contingency event. A second contingency event occurs when two resources are lost. In 2008, $143.4 million in NCPC was paid for the second contingency coverage in SEMA. Most, if not all, of the total NCPC payments in SEMA were to Canal.

In 2009, NSTAR made a number of short-term transmission upgrades to bolster transmission infrastructure in LSM and address the significant NCPC costs. NSTAR's short-term transmission improvements have greatly reduced the NCPC costs in the area,

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[7] Two small wind projects on Cape Cod totaling less than 2 MW ICAP were not included in the model.

[8] Cape Wind's total ICAP is insignificantly higher than LAI's generic treatment, but its development schedule is accelerated relative to the step-up incorporated in MarketSym.

[9] See Mirant's presentation to the ISO-NE Planning Advisory Committee, March 31, 2009.

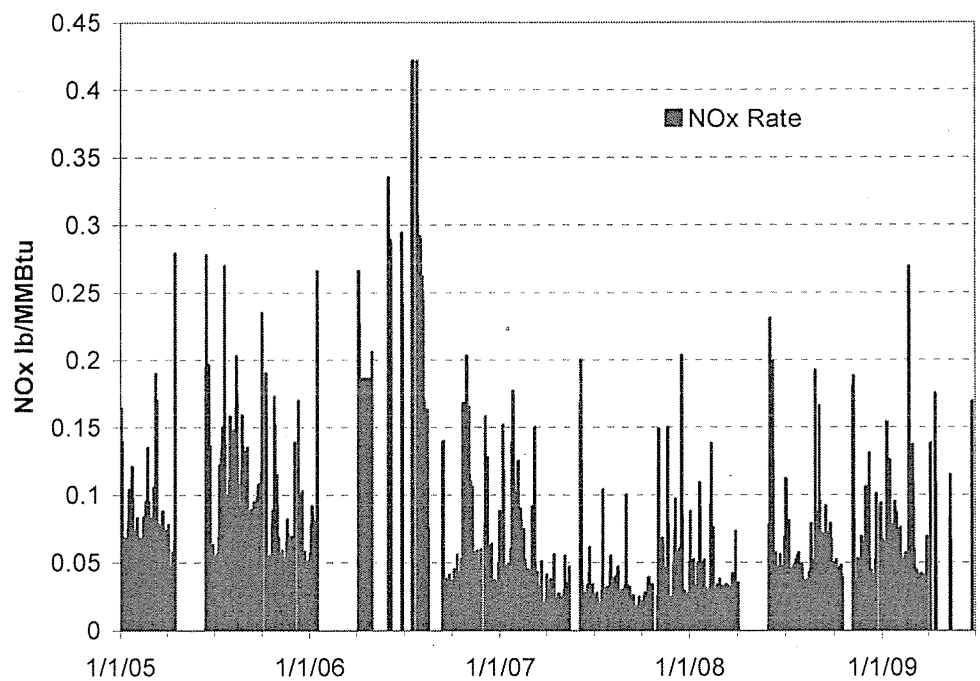
by reducing reliance on Canal. Following that success, further upgrade are necessary. According to ISO-NE's Long-Term SEMA Report published January 20, 2009 (at p. 5), "While load shedding can be relied upon for a few years, as load continues to grow the operational headroom afforded by the short term upgrades will be reduced and additional reinforcements in the area, either transmission or generation, will be necessary in order to operate the area reliably without reliance on Canal generation."

4.2.2 Environmental Compliance

<u>*Air Permit*</u>

Canal Station currently operates under an Air Operating Permit (AOP), finalized on January 9, 2009, which expires on January 9, 2013. Canal Unit 1 is equipped with selective catalytic reduction (SCR) for NOx control. Unit 2 uses selective non-catalytic reduction (SNCR). SNCR has lower capital and operating costs, but the NOx removal is less efficient, as evidenced by Figure 5 and Figure 6. Both units have electrostatic precipitators to control PM emissions, but neither unit has a scrubber for SO_2 removal.

Figure 5. Canal Unit 1 Historic NOx Emissions[10]



[10] Data from EPA Clean Air Markets database.

Figure 6. Canal Unit 2 Historic NOx Emissions

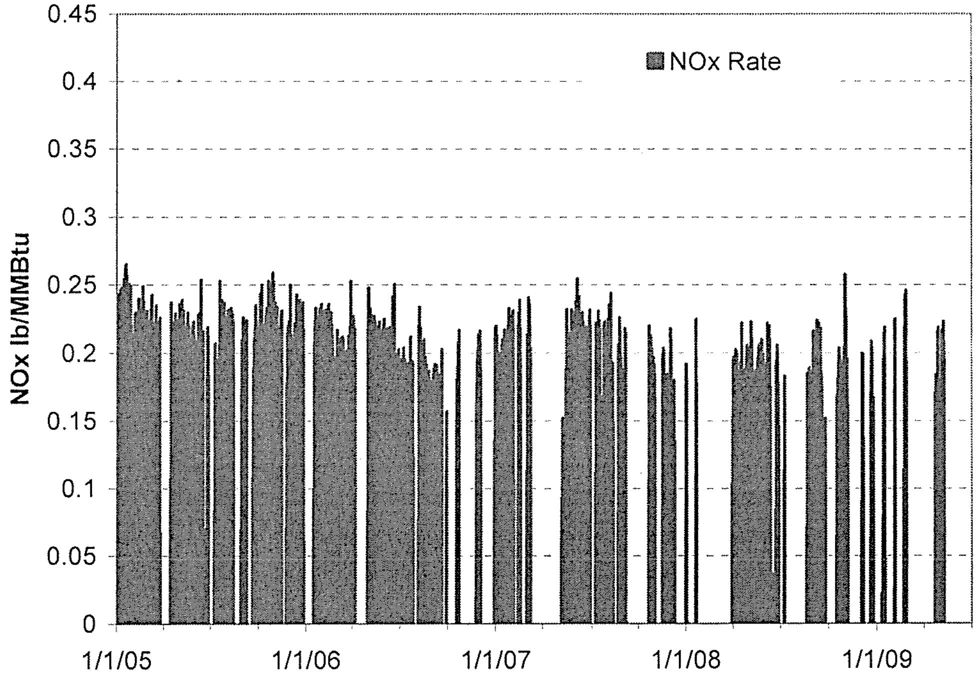


Figure 7. Canal Unit 1 Historic SO_2 Emissions

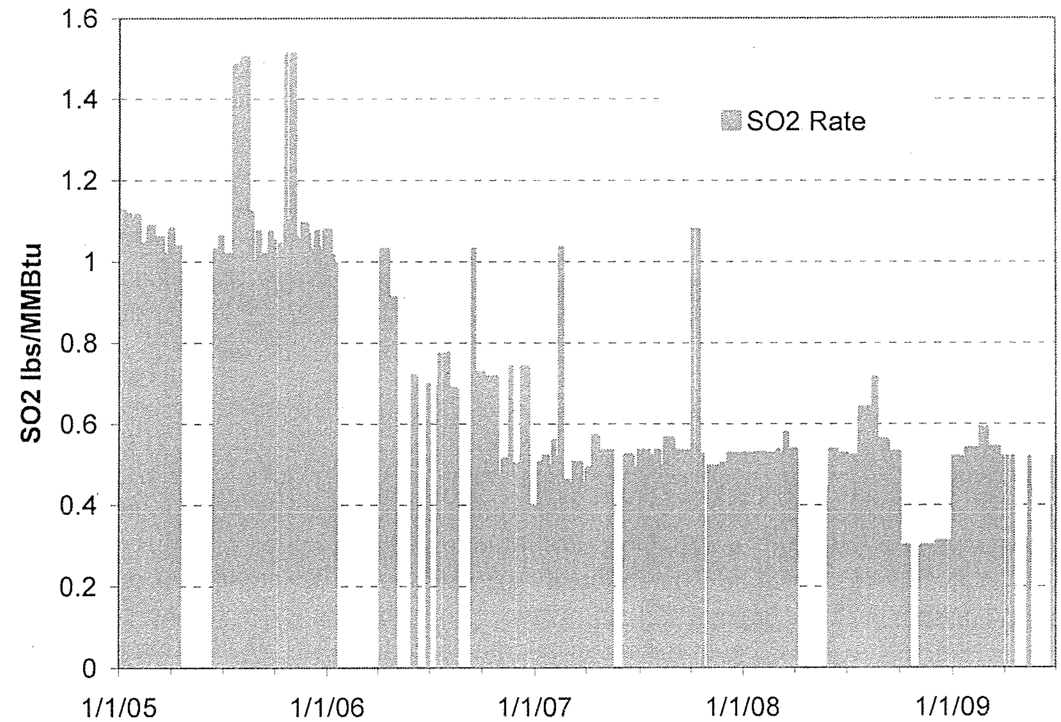
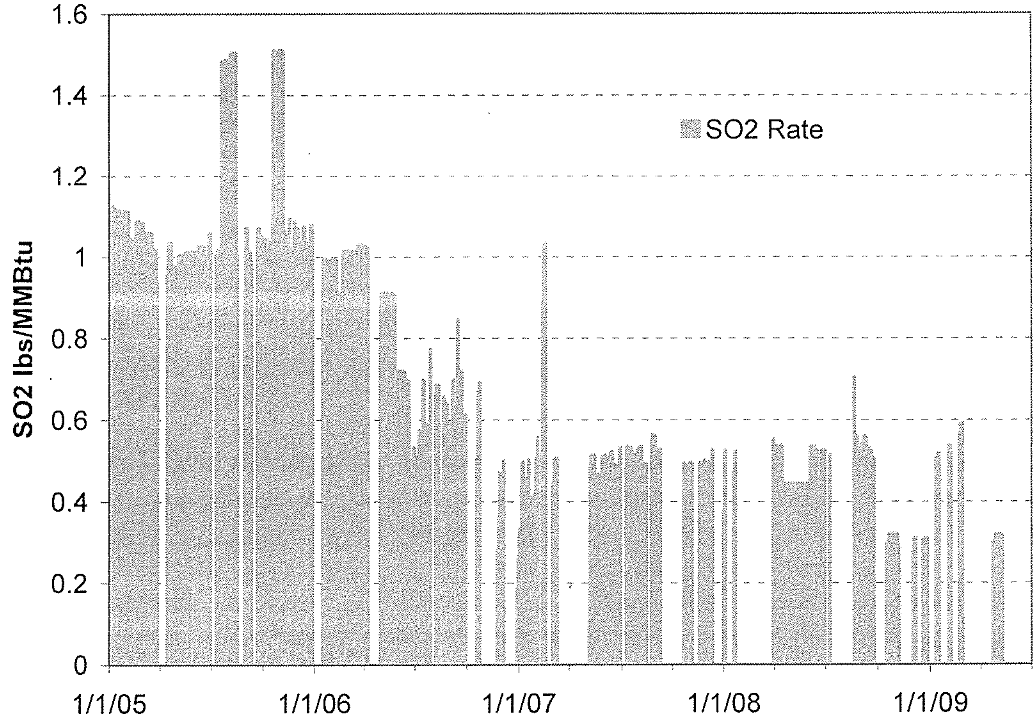


Figure 8. Canal Unit 2 Historic SO_2 Emissions



The AOP allows Canal some flexibility in complying with its emissions limits. The plant can average its emission rates on a 12-month rolling basis for NOx and SO_2. Over the study horizon, Canal is likely to face new emissions restrictions that may require additional operating costs and/or operating restrictions. While the EPA is currently developing new federal regulations to implement the CAIR that was remanded in December 2008, Phase I of the CAIR has been effective in Massachusetts since January 1, 2009.[11] Phase II is effective January 1, 2015. CAIR does not impose limits on plant emission rates or mandate retrofit of control technologies, but instead is implemented as a cap-and-trade system. We account for the impact of CAIR Phase II on Canal (and all other fossil-fired plants across the region) by including the cost of NOx allowances in its variable operating costs.

Canal is subject to the Regional Greenhouse Gas Initiative cap-and-trade program, and the station's operating costs include the cost of acquiring CO_2 allowances. If greenhouse gas legislation is implemented on a national basis, CO_2 allowance costs are likely to increase. Both Waxman-Markey (HR 2454) which passed the House in June 2009 and Kerry-Lieberman envision a cap-and-trade system with an initial compliance date of 2013. Although this timeline is undoubtedly aggressive, for the purpose of our analysis we have assumed that a federal CO_2 allowance program is in place by the start of our study period, 2013. We account for the additional operating costs by adopting the Energy

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[11] Massachusetts Clean Air Interstate Rule, 310 CMR 7.32

Information Administration's "Zero Bank" forecast of CO_2 allowance prices under HR 2454, which is very similar to the Congressional Budget Office forecast. The CO_2 allowance price forecast ranges from $12.69 per ton in 2013 to $30.14/ton in 2022 (in nominal dollars).

Over the period 2011-2013, Canal will also be required to comply with EPA's Regional Haze Rule, which requires emission sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas to install Best Available Retrofit Technology (BART).[12] Canal may have prepared a plan to achieve BART, but it is not publicly available at this time. For the purpose of our analysis, we assume that Canal will meet BART by firing only 0.3% sulfur RFO in Unit 1. Unit 2, which is dual-fueled, will burn gas during the non-heating season, and 0.3% sulfur RFO during the heating season when gas deliverability along Algonquin's G lateral from Mendon, MA to Bourne, MA is normally constrained.

Over the study horizon, the Canal Station is likely to face new environmental compliance requirements that may trigger substantial CapEx, additional operating costs and/or operating restrictions. Because such additional costs are not included in our analysis, the results are conservative in relation to Canal Station's long-term economics.

NPDES Permit

Canal Station currently withdraws cooling water from and discharges to the Cape Cod Canal. Steam turbine condenser waste heat is rejected to the Cape Cod Canal by means of a once-through cooling water system. Water for the cooling system is withdrawn at a rate of approximately 518 million gallons per day through two cooling water intake structures, and heated water is discharged through two outfalls.[13] Canal has been operating under a 1989 National Pollutant Discharge Elimination (NPDES) permit that has been administratively extended, pending finalization of a new permit. In August 2008, the U.S. EPA issued a final NPDES permit for Canal, which incorporated new requirements for existing facilities under the Clean Water Act (CWA) Section 316(b). The permit required the plant to replace its once-through cooling water system with a closed-cycle cooling system to minimize impingement and entrainment of fish, eggs, and larvae. The permit also required improvements to the fish return system and additional requirements with respect to thermal discharge limits. Mirant filed an appeal and the EPA subsequently withdrew certain provisions of the final permit and re-noticed those provisions in the form a draft permit for public review and comment. The draft permit does allow Mirant the flexibility to utilize any technical or operational approach that can achieve reductions in fish mortality comparable to what would be achieved with closed cycle cooling.

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[12] On January 7, 2010, the EPA proposed stricter standards for ground-level ozone, to be phased in over the next two decades. We have not analyzed the implications of these new rules.

[13] U.S. EPA, Mirant Canal Re-Notice December 2008 Fact Sheet

In comments on the draft permit, Mirant estimated that the cost of retrofitting the facility with closed cycle cooling would be $122 million (2008$). This CapEx is generally consistent with published studies for facilities with similar water intake rates.[14] Government agency studies also cite typical additional costs consisting of:

- Additional power requirements and lost output due to higher condensing temperature for the cooling system in the range of 1.0 to 1.5% of plant capacity;
- Additional maintenance costs in the range of 1 to 3% of system capital costs annually; and
- Reduction in plant efficiency in the range of 1% on an annual average basis (consistent with a reduction in net output with no change in fuel input).

In preparing documentation for its NPDES permit renewal in 2003, Canal evaluated six technologies to retrofit or replace its cooling water intake system.[15] The EPA ultimately determined that Alternative 6, installation of closed-cycle cooling, was the best technology available (BTA) for minimizing adverse environmental impact. However, the agency acknowledged that one other alternative, involving retrofit of the intakes with submerged, cylindrical wedge wire screens, "might be able to satisfy CWA Section 316(b)'s BTA requirements and...should continue to be considered in future analyses as a potential means of compliance."[16] The study identified a number of engineering limitations that would need to be addressed for effective installation and operation of the screens and associated facilities. These included disposal of dredged spoil, proximity to the navigation channel, vulnerability to icing conditions, and increased noise due to the air backwash system air compressors. Due to these engineering issues, Canal's construction cost estimate for this alternative, $11.25 million (2003$), is very likely on the low side, but is used in the present context solely to place Canal's going forward economics in its most favorable light. The Canal report did not identify any capacity or efficiency penalties associated with this alternative.

Under Canal's current operating conditions, it is possible that retrofitting the cooling water intake structures with screens to reduce entrainment of aquatic organisms, combined with the reduction in operating hours due to the short-term transmission upgrades, may satisfy the requirements under Section 316(b). LAI estimated the cost for retrofit of the cooling water intake structures with screens by escalating Canal's 2003 estimate and adjusting the cost based on data compiled by the EPA as part of the

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[14] Maulbetsch, John, "Costs Associated with Flow Reduction," in EPA, Department of Energy, National Energy Technology Laboratory, *Proceedings Report on Cooling Water Intake Technologies to Protect Aquatic Organisms*, p. 112, May 6-7, 2003.

[15] Alden Research Laboratory, Inc., "Evaluation of Fish Protection Alternatives for the Canal Generating Station," October 2003, p. 4-3, referenced in EPA 2005 Fact Sheet,

http://www.epa.gov/region1/npdes/mirantcanal/

[16] EPA 2005 Mirant Canal Fact Sheet p 43.

agency's economic impact analysis of the Section 316(b) Phase II final rule.[17] Based on the cost for installing similar retrofitted equipment on comparable plants in similar environmental settings, and assuming that additional site-specific costs will be required to address the engineering challenges at Canal, LAI conservatively estimated that the CapEx for retrofitting the cooling water intake structures at Canal would be $17 million.

We further assumed that interconnection for either a closed-cycle cooling tower or the retrofit technology would require a downtime of two months, which would be scheduled during the shoulder months when any foregone energy revenues would be negligible. According to the FCM rules, Manual 20, and OP5, Canal's regular capacity payments would not be reduced due to a 2-month planned outage for the environmental upgrades, provided that the outage is not scheduled for the peak demand part of the year and ISO-NE approves the schedule in advance.

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[17] EPA, *Economic and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule*, February 2004, EPA-821-R-04-005, and *Technical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule*, February 12, 2004 EPA 821-R-04-007.

5 CANAL STATION FINANCIAL ANALYSIS

In order to evaluate Canal's future participation in the ISO-NE's capacity and energy markets, and the cost to load compared to the Project, LAI developed a ten-year outlook of Canal's going concern value, 2013 through 2022. Mirant is not required to disclose Canal's fixed and variable operating expenses on a plant-specific basis, so we have therefore researched historical data for similar generation and exercised professional judgment to forecast Canal's operating expenses over the forecast period. These operating expenses include fixed and variable costs, but do not include capital recovery.

Canal's going concern value is driven by its ability to recoup its total out-of-pocket cash costs through the sale of capacity, energy and ancillary services. Canal's total operating expenses reflect the incurrence of fixed and variable operating costs. Total fixed operating expenses are invariant to the level of generation output. They include cash operating expenses such as labor, O&M costs, insurance, general and administrative costs allocable to the facility, security, and property taxes or payment in lieu of taxes (PILOT). Canal's variable operating expenses vary in direct proportion to the level of generation output. Such costs are primarily fuel related, but also include miscellaneous non-fuel variable O&M costs.

Our starting point in evaluating fixed costs was the level of fixed costs disclosed by Canal's prior utility owners more than fifteen years ago when Canal was part of the rate base of Commonwealth Energy System and Eastern Utilities (EUA).[18] Additional due diligence was performed in order to validate the reasonableness of these numbers relative to more recent cost and performance data from like units in New England. To project Canal's variable costs, we have simulated the average weekly / seasonal dispatch of the facility in order to quantify how much fuel and variable O&M costs are necessarily incurred to produce market based energy. As Mirant's investment in Canal is sunk, we have ignored Mirant's ability to recoup its original investment as well as earn a return on investment (ROI) over time. Depreciation expense is therefore ignored, but to the extent Canal generates financial losses, we have recognized the consolidated income tax effect realized at the parent level. Regarding capital outlays, Canal faces significant environmental upgrade costs in the near term in order to operate without violating anticipated permit conditions. While the structure of the financial analysis ignores sunk costs, the decision to outlay environmental CapEx must be rationalized based on Mirant's ability to realize a reasonable return on that investment going forward.

The determination of Canal's financial condition reflects the *status quo*, that is, the existing transmission topology of LSM. Therefore, to determine Canal's financial condition on a going forward basis, we have quantified Canal's cash operating margin without the Project in the transmission topology of the region.

[18] Commonwealth Energy System owned 100% of Unit 1 and 50% of Unit 2. EUA owned 50% of Unit 2.

5.1 Fixed O&M

To quantify Canal's fixed O&M expenses, LAI first reviewed Canal's FERC Form 1 production expense data over the four year period 1995-1998. Prior to divestiture, Commonwealth Energy reported production expense data for its ownership share of the Canal plant, *i.e.*, 100% of Unit 1 and 50% of Unit 2. Hence, LAI doubled the Unit 2 data to account for EUA's prior ownership of 50%. The Form 1 data indicate that generation from both units increased steadily from a total of 2.6 TWh in 1995 to 6.1 TWh in 1998.[19] The Unit 1 supercritical design had an average heat rate of 9,505 Btu/kWh over the four year period. Unit 2 had an average heat rate of approximately 10,500 Btu/kWh.[20] We ignored historical fuel data.

Canal's non-fuel production expenses varied insignificantly from 1995 to 1998, as shown in Table 2. During the historic period energy production more than doubled. The comparative insensitivity of these line item expenses during a period when Canal's generation output varied substantially confirms our treatment of such non-fuel production expenses as fixed not variable. Prior to divestiture, non-fuel production expenses averaged $27.36 million (1998 dollars) and the plant operated at an average 45% capacity factor over the four year period.

Table 2. Canal Non-Fuel Production Expenses ($ millions)

	1995	1996	1997	1998
Generation (GWh)	*2,604.2*	*3,014.2*	*5,416.5*	*6,107.9*
Maintenance Expenses	$13.46	$14.38	$10.86	$13.27
Prod'n Oper, Supv & Engr	$ 2.97	$ 2.64	$ 3.05	$ 2.82
Other Expenses	$ 9.57	$10.74	$11.39	$11.21
Total Non-Fuel Expenses	$26.00	$27.75	$25.30	$27.30

Table 3. Canal Average Non-Fuel Production Expenses Adjusted for Inflation ($ millions)

	Canal (1998 $)	Canal (2010 $)
Maintenance Expenses	$13.39	$18.13
Prod'n Oper, Supv & Engr	$ 2.95	$ 4.00
Other Expenses	$11.02	$14.93
Total Non-Fuel Expenses	$27.36	$37.07

[19] 1 TWh = 1000 GWh or 1 million MWh.

[20] Unit 2 1996 outlier heat rate data of 13,058 Btu/kWh was ignored.

The adjusted non-fuel production expense derived from Form 1 reports represents an average 2010 cost of about $37 / kW-yr. To further confirm our analysis, the inflation-adjusted cost based on the FERC Form 1 reports was compared to recent cost of service filings made by owners of like STG plants in New England. Such filings were made by generation companies seeking RMR contracts at FERC. LAI found that the respective RMR filings at FERC provided useful and contemporaneous cost data for substantially similar technology using RFO and/or natural gas in New England. The annualized cost of running like RFO or dual fuel STG units in New England is expressed on a $/kW-yr basis in Table 4.[21]

Table 4. RMR Contract Costs for New England STGs

Station	Sithe New Boston Units 1 & 2	NRG Norwalk Harbor Units 1 & 2	PSEG Bridgeport Harbor 2	PSEG New Haven Harbor	NRG Middletown Units 2, 3 & 4	NRG Montville Units 5 & 6	Mystic Unit 7
Total Capacity, MW	700	330	131	448	753	488	565
Filing Year	2000	2008	2008	2008	2005	2005	2005
Annual Fixed O&M							
$ Million (2010 $)	$11.25	$31.05	$6.32	$17.86	$45.19	$28.26	$30.66
$/kW-yr (2010 $)	$16.07	$94.08	$48.28	$39.86	$60.02	$57.92	$54.26

The capacity-weighted average of the costs above for all stations is $49.95 / kW-yr in 2010 dollars. For various reasons, we consider New Boston and Norwalk Harbor to be outliers. When the outliers shaded on the left are excluded, the average is $53.79 / kW-yr. Given Canal's technology type and age, the more recent costs reported by the post-divestiture owners support LAI's use of $50 / kW-year as a proxy for Canal's total non-fuel, fixed O&M costs.

A review of pre-divestiture Form 1 filings for the same stations shows that there is no unassailable benchmark that can be used to relate pre-divestiture and post-divestiture costs. In Table 5, we nevertheless present the historic Form 1 non-fuel production cost data for the New England STGs of relevance in performing this analysis.

[21] We note that Canal is significantly larger than other RMR units in New England. Canal's scale economy was therefore considered in deriving annual fixed O&M expenses.

Table 5. FERC Form 1 Production Cost Data

Station	UI New Haven Harbor	UI Bridgeport Harbor 1 & 2[22]	CL&P Norwalk Harbor 1 & 2	BECO New Boston 1 & 2
Total Capacity, MW	431	661	330	718
Form 1 Years	1995-98	1995-98	1997-99	1995-97
Non-Fuel Production				
$ Million (2010 $)	$11.1	$24.4	$16.7	$30.1
$/kW-year (2010 $)	$26	$37	$51	$42

In addition to the review of Canal's FERC Form 1 data many years ago, and the underlying cost data for those STG units whose owners more recently submitted cost of service data at FERC, LAI reviewed information from Mirant. We limited our review to Mirant's 10-K reports. Mirant is not required to submit FERC Form 1 data, but the company is required to provide financial information to the Securities and Exchange Commission (SEC). A portion of the information it files on a regular basis at the SEC relates to the financial performance of Mirant's business units in the Northeast. In Mirant's SEC 10-K Reports, Mirant aggregates its fixed O&M costs for the business segment in the Northeast. This business segment includes Canal, but also includes the Kendall Station in Cambridge, diesels on Martha's Vineyard, and the Bowline Station in New York.[23] There have been other changes over the years as well, rendering use of Mirant's prior 10-K reports prior to 2005 more challenging.

The O&M costs for 2006-08 were then adjusted for inflation. Based on information from Mirant, the all-in annual cost for the Northeast business segment was $166.1 million (2008 dollars). The total capacity of the current fleet is 2,535 MW, yielding an average O&M cost of $66 / kW-yr. If costs are allocated based on the ratio of pre-divestiture costs as reported in Form 1 for the same generating units, a greater portion of the total would be allocated to Canal. Under this method, the resultant fixed O&M cost is $96 / kW-year, about $108 million per year.

Upon comparing the two approaches for estimating the non-fuel fixed O&M costs, we elected to utilize the more conservative, (*i.e.* lower) value of $50 / kW-year based on cost data from like generation plants seeking beneficial RMR contracts at FERC, as summarized in Table 4.

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[22] It should be noted that UI reported Bridgeport Harbor Units 1 and 2 together, even though Unit 1 (since retired) was coal fired, while Unit 2 is oil fired.

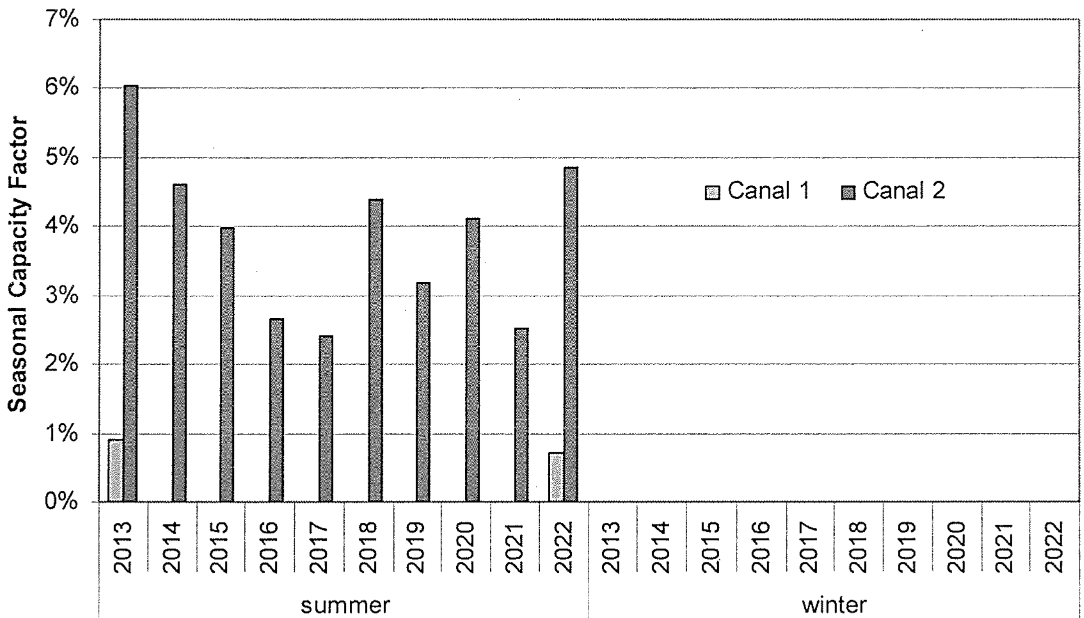
[23] Mirant retired the 540 MW Lovett Station in New York in 2005. Prior to 2005 the Lovett Station was included in this generation group.

5.2 Operating Revenues

5.2.1 Energy Revenues and Uplift

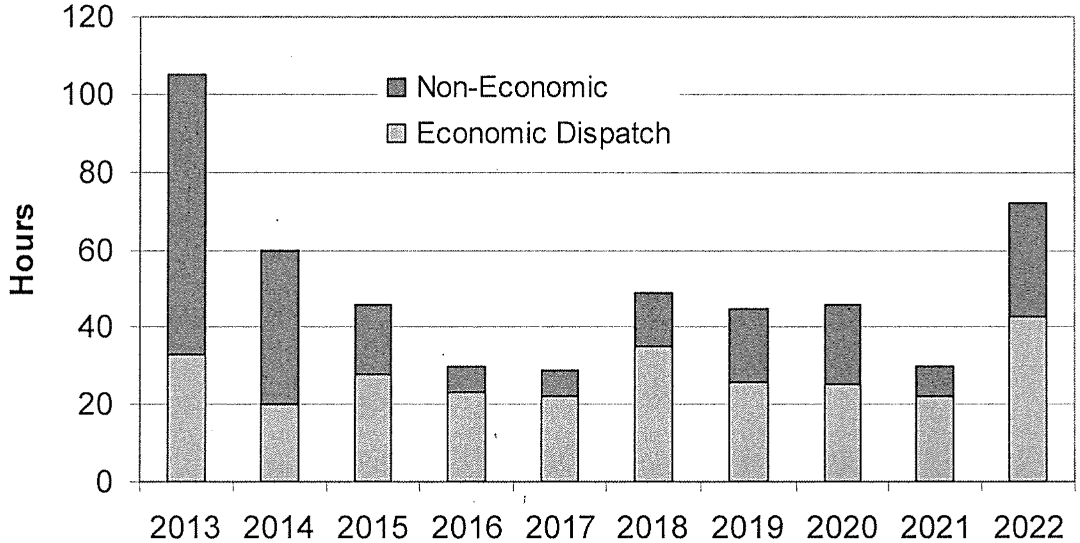
The results of the production simulation analysis show that Canal will operate sparingly over the forecast period. Canal is forecast to operate exclusively in the summer months, May through September. Because Unit 2 has a much lower normal minimum load (NML), ramps more quickly than Unit 1, and is capable of burning less costly natural gas, nearly all generation from Canal is produced by Unit 2. We project that energy production from Canal will be very low, in line with 2009 actual data.

Figure 9. Canal Station Seasonal Capacity Factors (No Project)



If no new transmission is built, Canal will continue to be dispatched both economically and out-of-merit-order to provide second contingency coverage. Canal's out-of-merit-order dispatch also reflects Canal's operating restrictions, *e.g.*, min-run time and NML. As shown in Figure 10, the out-of-merit dispatch decreases, but is never zero over the forecast period.

Figure 10. Canal's Annual Dispatch In- and Out-of-Merit-Order



Forecasted revenue from Canal's sale of energy is shown in Figure 11.[24] Absent the Project, we have quantified uplift revenues payable to Canal.[25] We have also assumed here that the station is not required to install cooling towers and therefore there is no capacity penalty or parasitic load.

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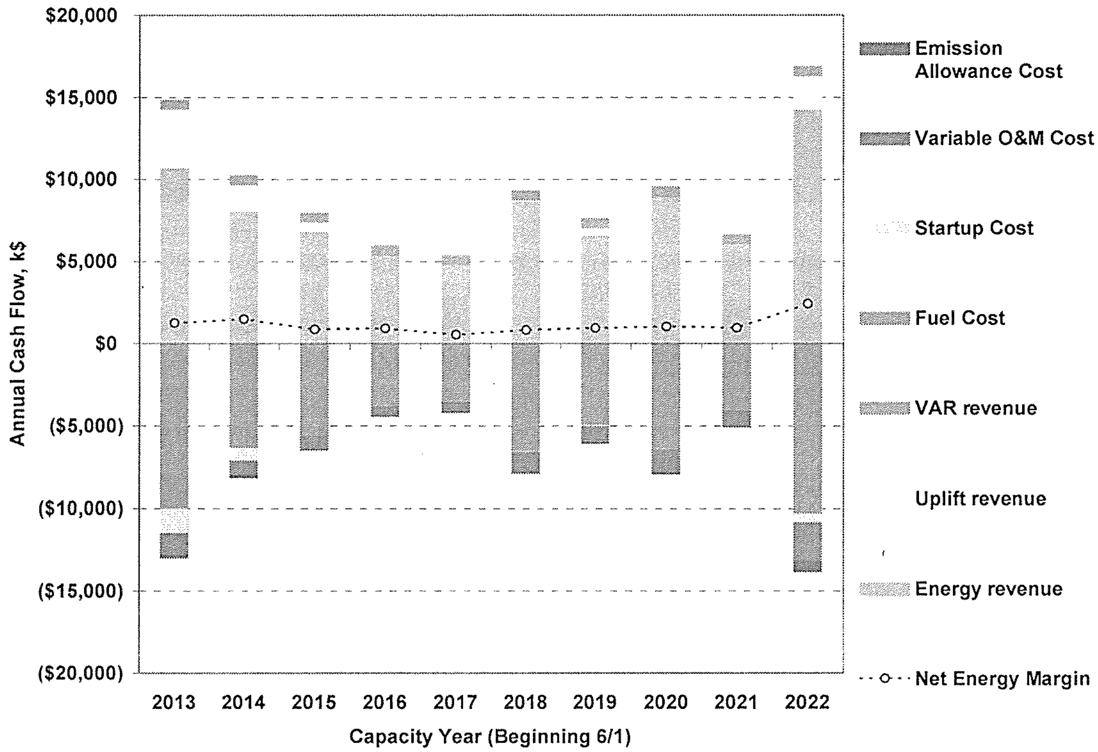
[24] Energy sales reflect DAM prices. Potential enhancements in the Real-Time Market have not been considered in this study.

[25] Under ISO-NE market rules, uplift costs are borne by the benefited load. Benefited load includes NSTAR's customers in SEMA. In this analysis, we report all relevant costs and benefits of relevance throughout New England rather than by zone or sub-zone. In practice, however, the cost of Canal uplift would be borne by NSTAR's customers.

Figure 11. Canal Station Annual Energy and Uplift Revenues

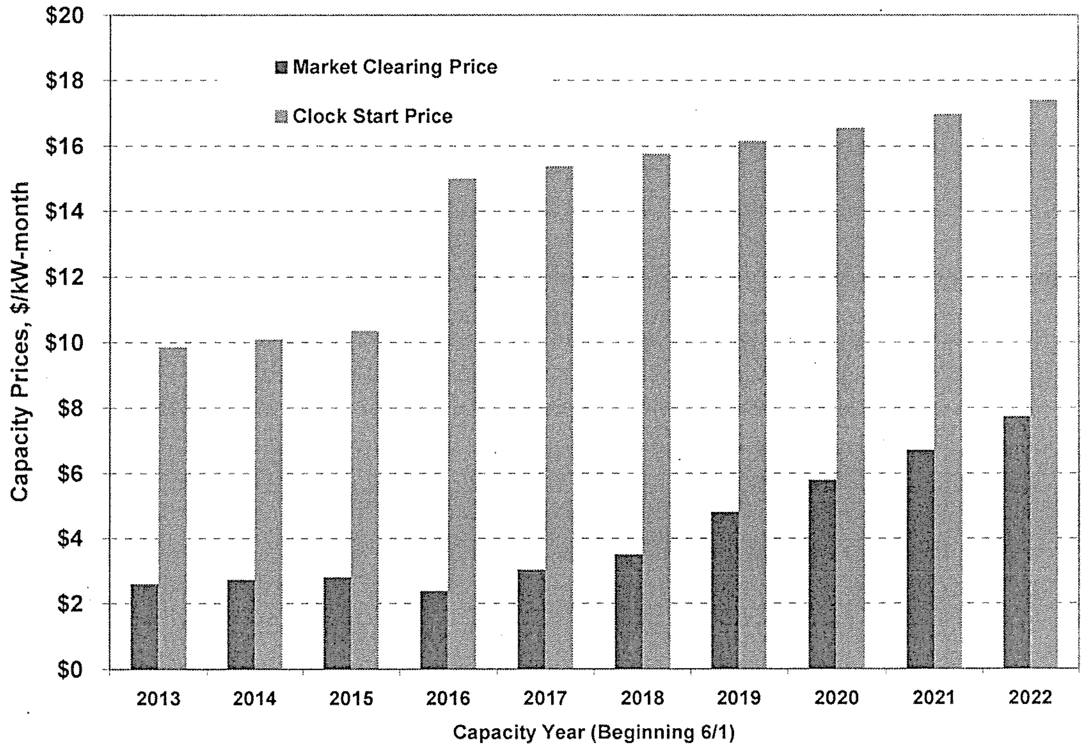


As shown in the dashed line above the x-axis, the net energy margin is the *difference* between the sum of energy, ancillary services, and uplift revenue and the sum of variable operating costs, *i.e.*, fuel, start costs, variable non-fuel O&M costs, and emission allowance costs. Reflecting Canal's inefficiency relative to other generation resources in SEMA, its net energy margin is very low, especially in relation to Canal's total operating costs and revenues. Operation provides only a very small amount of cash flow, which is insufficient to cover fixed operating costs (not shown in Figure 11) or provide a return to owners. Importantly, the cash flows in Figure 11 are associated with energy sales and uplift only, and do *not* include the fixed operating costs or capacity revenues.

5.2.2 Capacity Revenues

Canal's primary source of revenue is the FCM. Canal participated in FCA#1-3, accepting full capacity obligations through May 31, 2013. Canal may continue receiving market capacity revenues, but capacity prices are forecasted to rise only slowly from the floor after 2016, as illustrated by the blue bars in Figure 12. The FCA starting price is nevertheless relevant.

Figure 12. FCM Price Forecasts



Because, absent the Project, Canal would be needed for reliability in Tremont East, Canal may elect to submit a de-list bid in the FCA. A static de-list bid is the price at which a resource will leave the market for the capacity year.[26] A permanent de-list bid is the price at which a resource will exit the capacity market forever and may retire. Static de-list bids and permanent de-list bids may be submitted at a price as high as the starting price in the auction. The FCA starting price continues to be set at two times CONE for the next three auctions. This value will be reset to $15/kW-month beginning with FCA#7, corresponding to the commitment period June 1, 2016 to May 31, 2017.[27] The maximum de-list bid price is illustrated as the red bars in Figure 12.

When a unit submits a de-list bid, ISO-NE System Planning conducts a reliability review to determine if a resource which has submitted a de-list bid is needed for reliability. If the ISO determines that the resource submitting the de-list bid is not needed for reliability, the de-list bid would be accepted in the FCA. If the price in the FCA drops below the de-list bid price, the resource would clear and it would not be considered a capacity resource for one year (static de-listing), or forever (permanent de-listing). If,

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[26] The de-listed resource has an option of participating in the energy market as a non-capacity resource.

[27] A non-priced retirement application is also an option under the ISO-NE market rules. Any resource may submit a non-priced retirement application and may be retained if needed for reliability under an RMR agreement until such a time when it is no longer required.

however, upon reliability need assessment, the ISO determines that the resource is needed for reliability, the de-list bid is rejected.[28]

Based on our analysis of the transmission interfaces and resources within Tremont East, we believe that only a single Canal unit would be needed for reliability. We have concluded that ISO-NE would not reject a de-list bid for both of the Canal units. See Section 7.1.1. Absent the Project, we expect that one of the units would be allowed to de-list and the other would not. If, on the other hand, the Project is added to the transmission infrastructure of the region, we have concluded that ISO-NE would allow both Canal units to de-list.

Permanent and static de-list bids are scrutinized by ISO-NE Internal Market Monitoring Unit (IMMU) and under certain conditions may be mitigated. Although the maximum de-list bid is two times CONE, the IMMU may review de-list bids that exceed 1.25 times CONE, and would mitigate the bids if it find them to be inconsistent with the resource's going forward and opportunity costs. A return of capital for Canal's sunk cost is not includible, but capital recovery on incremental investment, including ROI, is includible in the de-list bid.[29] Compensation at the level of a rejected de-list bid is equivalent to the formerly negotiated RMR agreement. Therefore, we refer to such payments from ISO-NE to Canal to maintain reliability in Tremont East as RMR equivalent, or "RMRe."

The deadline for submission of permanent and static de-list bids for FCA#4 for commitment period from June 1, 2013 to May 31, 2014 has passed, and Canal did not submit a de-list bid. Of course, Canal may still submit a dynamic de-list bid during the course of FCA#4, but only when the price in the descending clock auction gets below 0.8 times CONE.

According to our analysis, we believe it is likely that Canal will submit a de-list bid beginning in either in FCA#5 or a subsequent capacity auction.

5.2.3 Ancillary Services

Canal is capable of providing voltage (VAR) support during its operation, including periods of light load, and receives ancillary services revenues from ISO-NE. According to Schedule 2 of the ISO-NE Open Access Transmission Tariff, the Base Capacity Cost (CC) rate for the period from June 1, 2007 through December 31, 2012 is $2.19/kVAR-year. ISO-NE converts the Base CC rate into an Adjusted CC rate on an annual basis, based upon the total lagging and leading VARs available to the system. For 2010, the

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[28] Following the annual FCA, ISO-NE will enter the de-listed capacity in the reconfiguration auctions on behalf of the load. If a new resource clears in the reconfiguration auction and is determined to be capable of substituting for the resource with the rejected de-list bid, the de-list bid formerly rejected for reliability clears and the resource is de-listed.

[29] De-list bids between 0.8 times CONE and 1.25 times CONE are presumed competitive, unless determined to be an attempt to manipulate the FCA. The de-list bid may be rejected if the IMMU finds that the bid is not competitive, and then the matter is reported to FERC.

Adjusted CC rate was $1.165/kVAR-year. The VAR CC rate is equal the Adjusted CC rate because the total Summer Claimed Capability of the qualified VAR resources is not at least 20% higher than the forecast peak adjusted reference load for the year.

According to the ISO-NE VAR Status Summary Report dated December 7, 2009, the total qualified VAR capability of Canal Unit 1 and Unit 2 is 259.475 MVAR and 194.092 MVAR, respectively. For 2010, the annual VAR payment to the Canal Station would therefore be approximately $528,000. We assume that the 2010 VAR CC rate and Canal's qualified VAR capability do not change appreciably thereafter over the forecast period.

5.3 Canal Station Economic Assessment

5.3.1 Financial Assumptions

The assessment of the going concern value of the Canal Station is based on the assumption that the need to make capital investments to meet new environmental requirements would trigger Mirant's examination of the facility's financial prospects over the intermediate to long term. Prior to the need date for new resources in New England, the capacity market is likely to remain soft, that is, well below CONE. At the point in time that environmental CapEx is needed to renew its permit, Mirant would be expected to evaluate the investment in new intake screens or a closed-loop cooling system against future cash flows from the plant. Absent a decision to renew its permit, Mirant would be expected to retire the plant as it has done in other jurisdictions.

As indicated in Section 4.2.2, we have considered two outcomes to Canal's NPDES permit renewal conditions: retrofitting the intake structures with screens, and replacing the once-through cooling system with a closed-loop system and cooling towers. We conservatively estimate the capital cost to retrofit the intake structures with screens to be about $17 million for both Canal units. If only one Canal unit continues to operate, we estimate the cost would be about $10 million. The capital cost of the closed loop cooling system, including cooling towers, was estimated at $128 million. For a single unit, we estimate the cost would be $64 million. The screens would require incremental fixed O&M expenditures of about $0.5 million per year per unit, while the closed-loop system would result in $1.3 million per unit in incremental annual O&M. We also estimated that the closed-loop cooling would reduce unit output by an average of 1.5%, with no reduction in fuel input.

The net salvage value of the facility was estimated at negative $5 million (a cost of $5 million), based on discussions with salvage companies. This net cost would be deferred if the plant (one or two units) is kept in service. Otherwise, it was assumed to be incurred in 2012.

The cash flows associated with keeping the plant in service consist of the following:

- Revenue from the sale of energy at the market clearing price for the zone (from simulation runs, adjusted for environmental upgrade effects)

- Uplift revenue from out-of-merit-order dispatch (from simulation runs)
- Revenue from the sale of capacity at the FCM clearing price *or* through RMRe revenues, if ISO-NE rejects Canal's de-list bid
- Ancillary services revenues
- Fuel and variable operating costs (from MarketSym simulation runs)
- Base fixed O&M costs at $50 / kW-year in 2010 $, indexed to inflation
- Incremental fixed O&M costs for environmental upgrades, including insurance at 0.5% of capital cost and PILOT at 2.5% of capital cost
- CapEx for environmental upgrades
- Incurred or avoided salvage effects
- Income taxes at an effective state and Federal rate of 40% and 20 year MACRS tax depreciation

5.3.2 Results

We constructed six cases to evaluate the cash flows for Canal under different assumptions regarding NPDES permit requirements and its status under the FCM.

Case 1: Postulate that Canal's NPDES permit renewal requires retrofit of screens on both intake structures and both units continue to operate. It receives market revenues for energy and ancillary services, and capacity is sold at the FCM clearing price (pro-rated) in each year over the study period.

Case 2: Postulate that Canal's NPDES permit renewal requires installation of closed-loop cooling for both units. Canal receives market revenues for energy and ancillary services, and capacity is sold at the FCM clearing price (pro-rated) in each year over the study period.

Case 3: Postulate that Canal's NPDES permit renewal requires retrofit of screens on the intake structure. ISO-NE determines that only one unit (Unit 2) is needed for reliability, therefore Unit 2's de-list bid is rejected and Unit 1 retires. Canal bids and receives capacity payments for Unit 2 based on the *minimum* required revenues for break-even present value of cash flows over the study period ("break-even RMRe"), but in no year can the bid price exceed the FCM auction clock starting price.

Case 4: Postulate that Canal's NPDES permit renewal requires closed-loop cooling. ISO-NE determines that only one unit (Unit 2) is needed for reliability, therefore Unit 2's de-list bid is rejected and Unit 1 retires. Canal bids and receives capacity payments for Unit 2 based on the *minimum* required revenues for break-even present value of cash flows over the study period ("break-even RMRe"), but in no year can the bid price exceed the FCM auction clock starting price.

Case 5: Postulate that Canal's NPDES permit renewal requires retrofit of screens on the intake structure. ISO-NE determines that only one unit (Unit 2) is needed for reliability, therefore Unit 2's de-list bid is rejected and Unit 1 retires. Canal bids and receives capacity payments for Unit 2 that are the *maximum* RMRe payments it can receive under the FCM, *i.e.*, the FCM clock starting price in each year.

Case 6: Postulate that Canal's NPDES permit renewal requires closed-loop cooling. ISO-NE determines that only one unit (Unit 2) is needed for reliability, therefore Unit 2's de-list bid is rejected and Unit 1 retires. Canal bids and receives capacity payments for Unit 2 that are the *maximum* RMRe payments it can receive under the FCM, *i.e.*, the FCM clock starting price in each year.

Annual cash flows, discounted at an after-tax hurdle rate of 12% over the 10 year horizon, are shown for each case in Figure 13 through Figure 18. In each figure, the dashed line represents the net annual cash flow. Note that in some of these cases, the RMRe increases significantly in 2016 when the auction clock start price jumps to $15/kW-mo and Canal can recover more of its investment. (See Figure 12.)

Figure 13. Canal Cash Flows – Case 1: Intake Screens, Capacity at Market

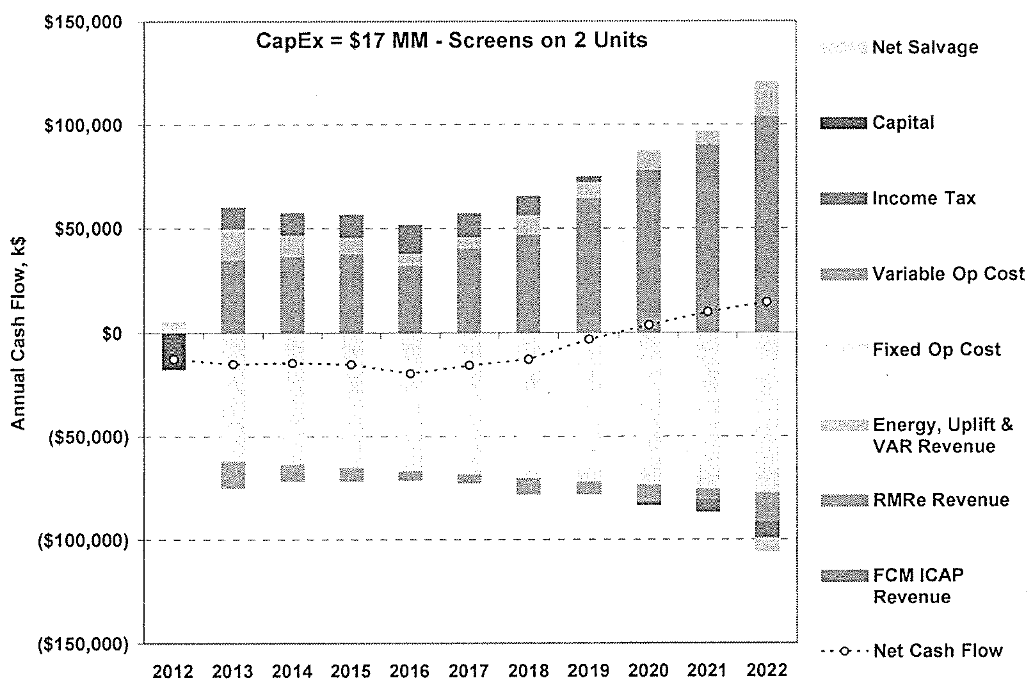


Figure 14. Canal Cash Flows – Case 2: Cooling Towers, Capacity at Market

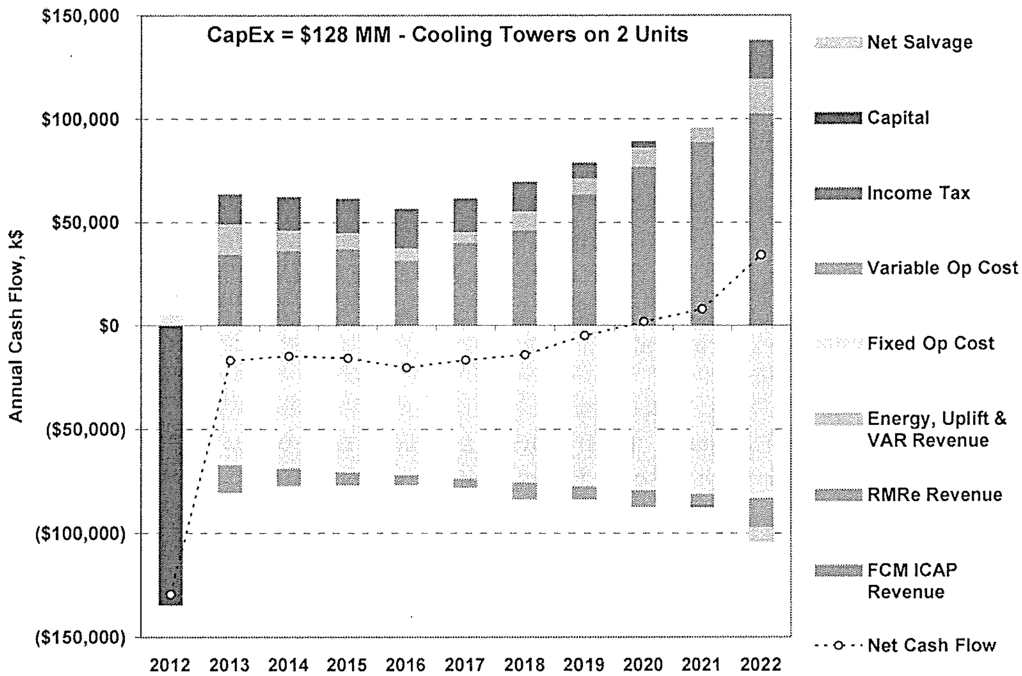


Figure 15. Canal Cash Flows – Case 3: Screens, RMRe at Breakeven

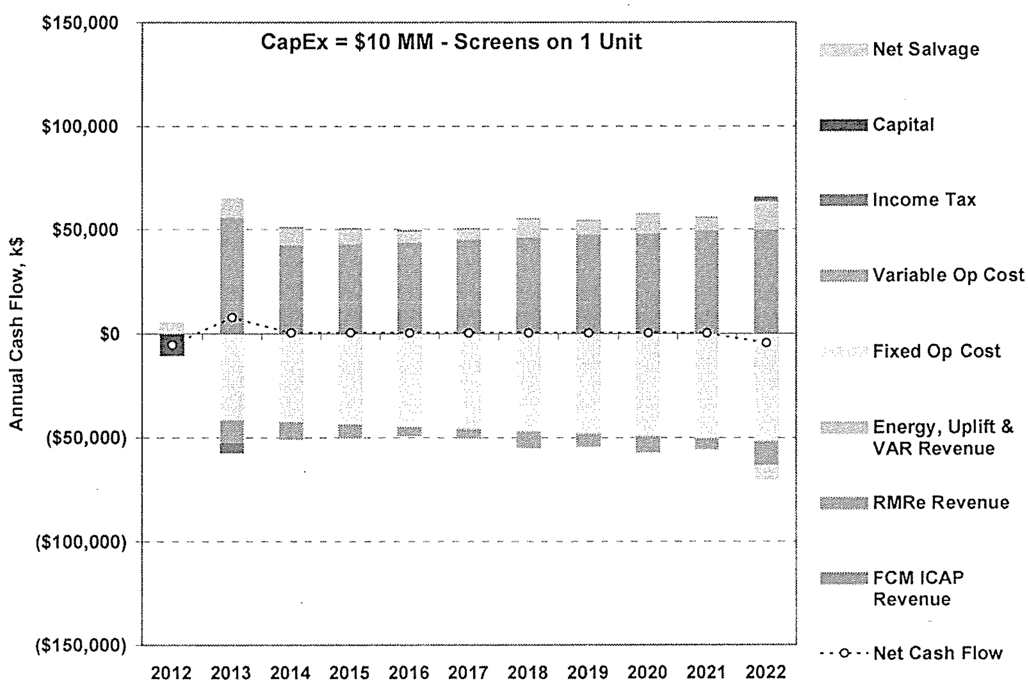


Figure 16. Canal Cash Flows – Case 4: Cooling Tower, RMRe at Breakeven

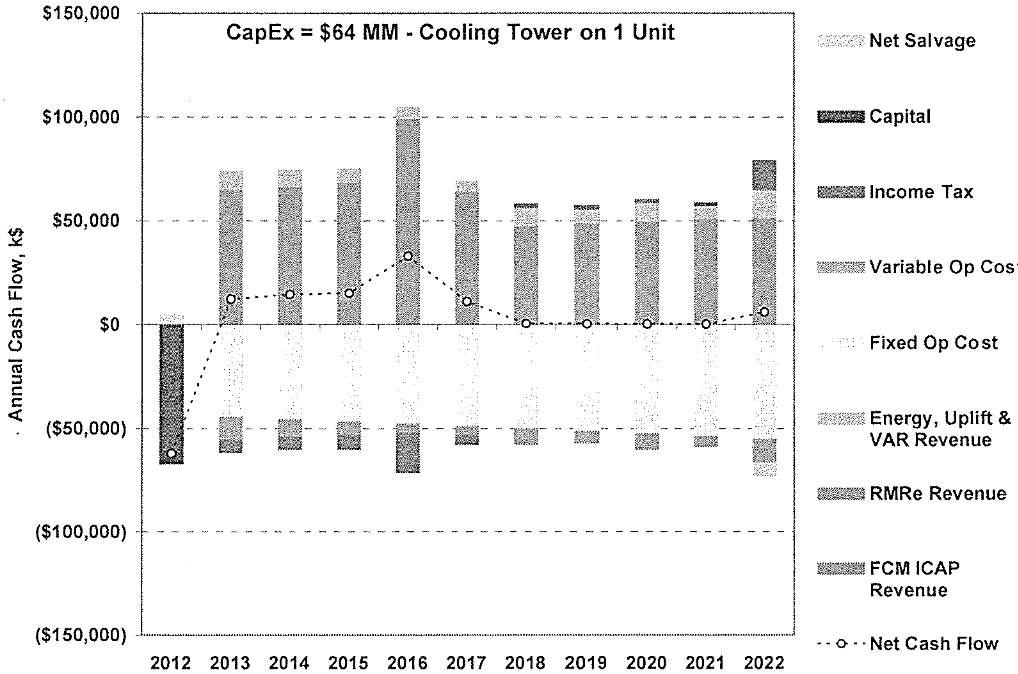


Figure 17. Canal Cash Flows – Case 5: Screens, RMRe at Maximum

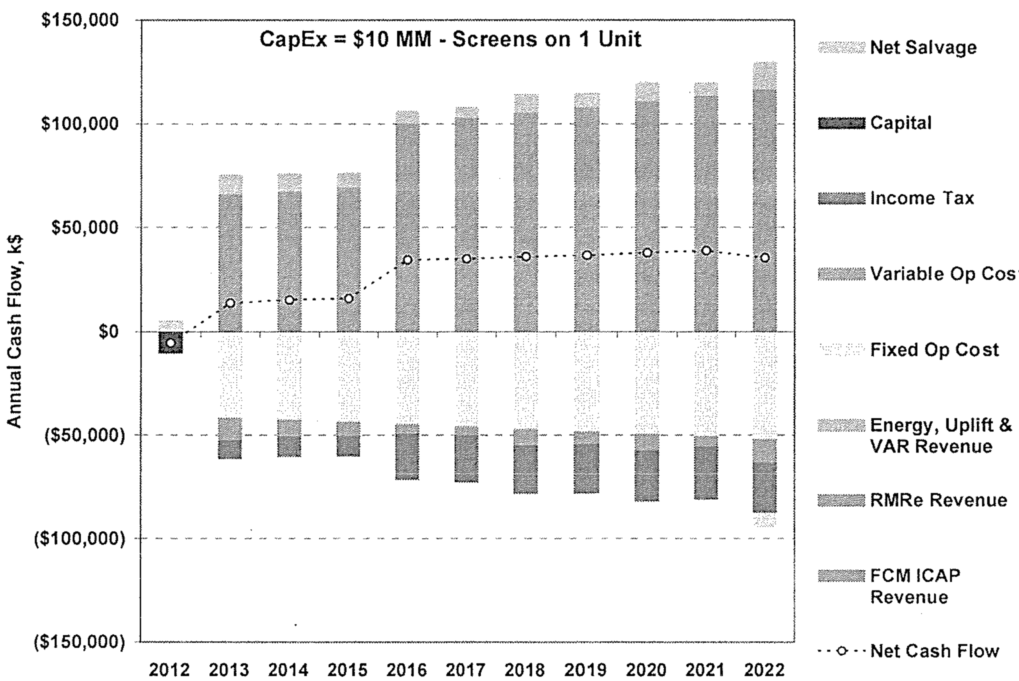
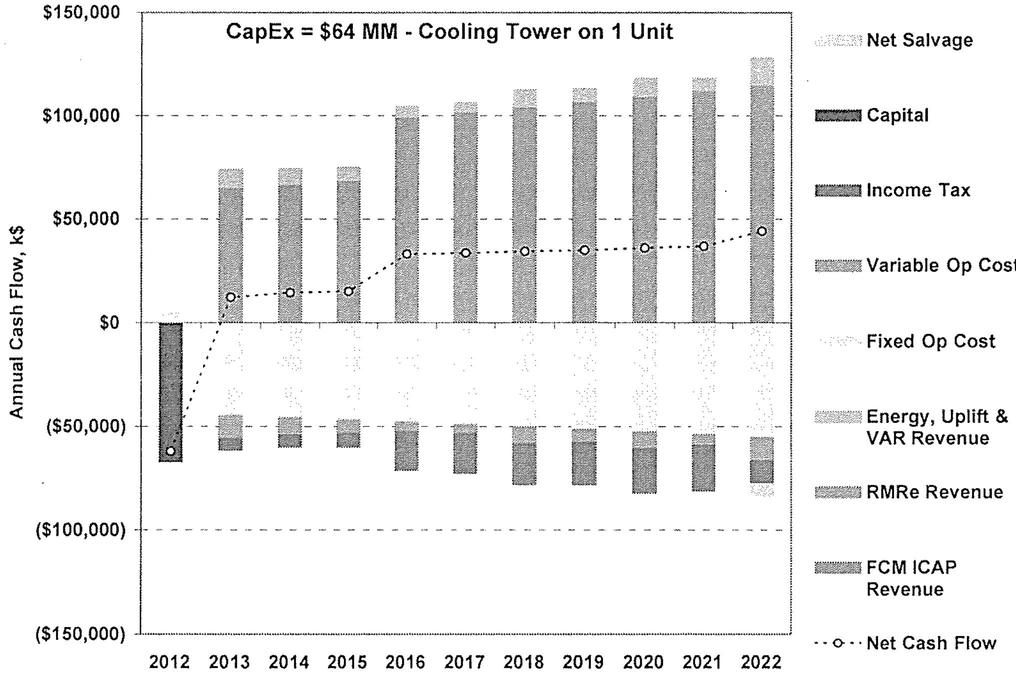
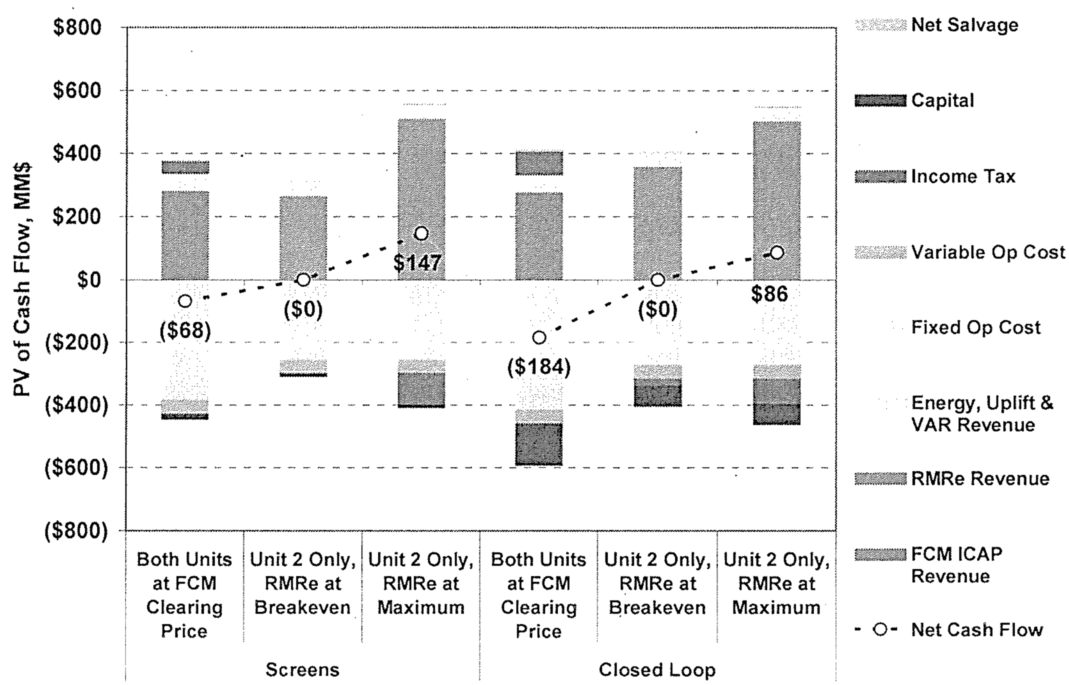


Figure 18. Canal Cash Flows – Case 6: Cooling Tower, RMRe at Maximum



The present values for the six cases are shown in Figure 19. Here, the cases are presented in the order of 1, 3, and 5 (the cases with retrofit screens) followed by 2, 4, and 6 (the closed-loop cooling cases). Net present value is negative for the first case in each group, which assumes that both units continue to operate receiving market capacity payments. For the second case in each group, the net present value is zero by design – RMRe payments exactly offset the negative sum of the other cash flow components. These cases are tantamount to Canal leaving money on the table, but they are nevertheless relevant for purposes of charting the lower limit for RMRe payments. In the third case in each group, the net present value is positive, since the RMRe payments exceed the minimum required for financial viability.

Figure 19. PV of Canal Cash Flows



The financial analysis indicates that sustained low FCM clearing prices will impair Canal's financial viability over a ten-year planning horizon. LAI believes that Mirant is unlikely to tolerate such a situation over any extended period. However, Canal can legitimately achieve a positive cash flow if it submits a de-list bid and ISO-NE determines that at least one unit is needed for transmission security. In this instance, the de-list bid for one unit will be rejected, and Canal would receive its bid price. Load would be obligated to provide RMRe payments to Canal for as long as one unit is needed for reliability. At a minimum, we expect that Canal's de-list bid in each year would ensure a breakeven present value of cash flows, including a return on the investment for the environmental upgrades only. At a maximum, Canal could submit a de-list bid as high as the FCM clock starting price, and receive the maximum RMRe payments in each year that the unit is deemed required for reliability. We believe that, in the absence of the Project, Canal is likely to receive RMRe payments somewhere between those indicated for the breakeven cases and those indicated for the maximum cases. If the Project is built, it will eliminate the possibility of any RMRe payments to Canal.

6 PROJECT ECONOMIC ASSESSMENT

6.1 Approach

In this section, we quantify the financial tradeoffs when the Project is added to the transmission infrastructure of the region. The economics of adding new transmission are evaluated on a regional basis; hence, we have ignored the FERC-approved transmission cost allocation and rate design methodology that applies to high voltage transmission projects in New England.

The net economic benefit or disbenefit of the Project was assessed by comparing forecasts of total net electricity costs to all of New England load *with and without* the Project. These comparisons assume no other changes to load or capacity resources. Each of the categories of costs and/or benefits included in the analysis is listed below, along with an explanation of how each is generally incurred or allocated.

Table 6. Cost Categories Included in Financial Analysis

Cost	Allocation Method
Capacity costs based on the FCM auction clearing price	Assigned to load in general, with exceptions for binding zones (Maine)
"RMRe" payments when ISO-NE deems that a resource is needed for reliability and its de-list bid is rejected	Assigned to benefited load
Market energy cost, based on zonal loads and clearing prices	Flows to load in corresponding zones (SEMA). No sub-zonal allocation to Tremont East. Aggregated for New England
Uplift costs (NCPC) paid to generator for out-of-merit-order dispatch	Assigned to benefited load
Transmission project capital recovery and maintenance costs	Socialized by load share in New England for reliability projects
Contract for Differences	Assigned to default supply service customers or to EDC's customers

Although the cost categories above are each allocated in a different fashion, for the purpose of this analysis the *total* net economic costs and benefits have been analyzed from the perspective of New England as a whole.[30]

We have used a discount rate of 10% to calculate present values over the study period.

[30] Price effects outside the region have not been included and appear to be minor.

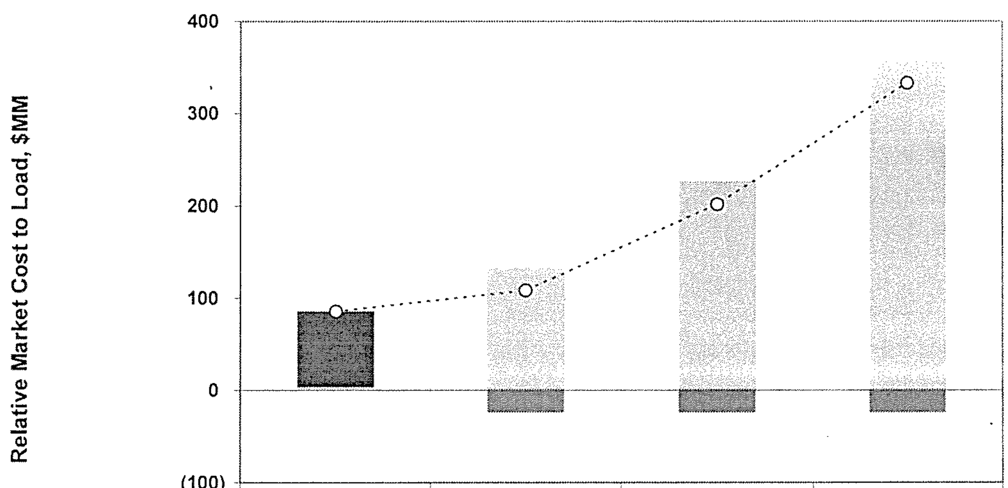
6.2 Project Fixed Costs

Based on ISO-NE's July 2009 project list update, the Pool Transmission Facilities (PTF) cost of the Project is $110 million. LAI has assumed an annual nominal dollar capital recovery charge rate of 13% for the Project and an annual fixed O&M cost of $0.5 million in 2010 dollars. These annual costs increase from $14.8 million in capacity year 2013 to $15.0 million in capacity year 2022.

6.3 Project as an Alternative to Canal

We have considered the effects on New England load costs when the Project is seen as an *alternative* to the Canal station. The Project would eliminate the need for Canal to be dispatched out-of-merit, but the energy that Canal would otherwise generate when it is committed for reliability must be replaced by resources elsewhere in the system. Figure 20 shows the present value of cost to load with the Project and under three cases reflecting Canal's behavior in the capacity market. In the first bar, the present value cost of the Project is shown as $85.7 million, reflecting recovery of capital cost and operating costs.

Figure 20. Present Value of Cost to Load – Canal as an Alternative



	Project Case (No Canal)	Canal 2 w Screens @ Breakeven RMRe	Canal 2 w Closed Loop @ Breakeven RMRe	Canal 2 @ Max RMRe
Project Capital Recovery	82.4			
Project Fixed O&M	3.4			
RMRe Cost		131.0	224.2	355.1
Uplift Cost		1.7	1.7	1.7
MTM Energy Cost		(24.0)	(24.0)	(24.0)
- - O - - Total	85.7	108.6	201.8	332.7

As discussed in Section 5.3, Canal's going concern value is impaired under market-based capacity and energy rates. Insofar as there are profitable options available to Canal through the de-list bid process for Unit 2, LAI does not believe that it is likely that Canal would tolerate a negative cash flow position over the long term when capacity revenues