Public Service Company of New Hampshire

d/b/a Eversource Energy

Least Cost Integrated Resource Plan

June 19, 2015

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I. Introduction

Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or the "Company") hereby files its 2015 Least Cost Integrated Resource Plan ("LCIRP" or "Plan") pursuant to the requirements of RSA 378:38. Eversource's most-recently approved LCIRP was filed on June 21, 2013 and accepted and found adequate in Order No. 25,659 (May 1, 2014) in Docket No. DE 13-177. This plan is filed in accordance with the requirements expressed in Order Nos. 25,459 (January 29, 2013), 25,659 (May 1, 2014) and 25,676 (June 12, 2014) and, pursuant to Order No. 25,676, is limited to Eversource's distribution and transmission planning. The planning horizion for this filing is the five-year period 2015-2019.

Eversource serves more than 500,000 homes and businesses in New Hampshire and is primarily responsible for the provision of safe and reliable electric service to its retail customers. Additionally, the Company also provides wholesale delivery service to the New Hampshire Electric Cooperative (NHEC), Unitil Energy Systems (UES) and several municipal electric companies. Under the distribution section of this Plan, Eversource describes how it fulfills its responsibility to provide service to all of its distribution customers, operate and maintain its distribution system, connect new customers, plan and build distribution plant for customers' peak demand requirements, and offer energy efficiency and demand side management opportunities to its customers. The distribution section also outlines the Company's system peak load forecasting methodolgy and how the forecast is used to assess future system needs.

The transmission section of the Plan describes how Eversource provides transmission service regulated by the Federal Energy Regulatory Commission ("FERC") and administered by ISO-New England ("ISO-NE"). The transmission section also provides details regarding transmission planning and investment consistent with ISO-NE's Regional System Plan ("RSP").

Uncertainty exists with regard to any potential investment in distribution or transmission assets. Eversource operates in a changing world, where future events, be they economic, legislative, customer-driven or regulatory are increasingly difficult to predict. The Company must therefore remain flexible throughout the planning horizion in order to shift planning priorities as the underpinning assumptions deviate from expectations.

II. Distribution Planning and Investment

Planning for expansion of the distribution system is determined by the System Planning Department's engineering forecast for peak demand. As the first step of the annual planning forecast process, Eversource's distribution System Planning Department produces an engineering forecast of demands for the overall system and by geographic area. The current methodology for forecasting is based upon historical data analysis, probability forecasts, and engineering judgment for Eversource's entire system as well as certain defined geographic areas of New Hampshire. The engineering forecast is reviewed annually, and updated based on actual peak demand data for each geographic area and the Company's total peak demand.

Ultimately, the distribution system must be capable of serving the peak load expected; therefore, a predictive forecast methodology which results in construction recommendations at appropriate future dates is important. A model that under-forecasts capital investment requirements will limit system capabilities during peak load periods, whereas a model that over-forecasts capital investment requirements will result in construction of facilities before they are required, or to a scale that is not necessary. Invariably, any model attempting to forecast future needs will yield an estimate that will differ from actual experience. It is important to note that the planning horizon for transmission system-connected projects is typically longer than for distribution system projects due to ISO-NE oversight and procedures. Distribution system-only projects inherently require shorter planning and construction periods and therefore allow greater opportunities to modify plans and adjust in-service dates as circumstances and load change.

A process flow diagram and corresponding narrative of the distribution planning process can be found in Appendices A and B.

A. Methodology

The first step in the development of the engineering forecast is identifying actual historical peak demands. Eversource records overall system peak load based on the highest single hour of demand as measured simultaneously at many points across Eversource's system and accumulated at the Electric System Control Center. The overall system peak is used to calculate the compounded growth rate for the Company's entire New Hampshire distribution system. Eversource also records each geographic area peak, which is used to calculate a load forecast for each area. The geographic area forecast is used in Eversource's model to identify capacity addition needs. Each area represents localized distribution systems and allows for an in-depth examination of the peak demand growth specific to that discrete area. Factors that influence a planning area are likely to be similar throughout the area, such as weather, economic activity, and customer profile (i.e., number of residential, small commercial and industrial customers). Each area is modeled as electrically separate, which allows load and peak demand growth assumptions to be matched with the specific distribution system construction needs appropriate for the area.

The forecast is based upon an area peak load occurring within the last five years and in a year with at least two consecutive 17 cooling degree days. If the 5 year historical peak is prior to the last year with consecutive days of 17 cooling degree days, the last year with consecutive days of 17 cooling degree days is used as the historical peak year. If the 5 year historical peak is after the last year with consecutive days of 17 cooling degree days, the data from the year that yields the larger forecasted value is used.

A growth rate for the first five years of the Company's ten year forecast is developed using inputs from historical growth, business climate, and local area knowledge. The growth rate for years six through ten utilizes the calculated compounded growth rate of the previous ten years adjusted for years with unusually mild weather. This typically results in a lower longer term projected growth rate and more accurately reflects Eversource's experience when forecasting over a ten year horizon. Once the projected growth rates are applied, adjustments to area loads are made to address the impact of large customer additions (e.g. a new 5MW customer).

If there is a new large customer or large customer expansion, that customer's projected load, as determined typically through discussions between the customer and Eversource Field Engineering, is then added to the area forecast in the year that the additional electric demand is expected to occur. This new or expanded load is then added to the yearly forecast for each subsequent year until this load is fully incorporated into the area load. A more detailed discussion of the forecast methodology can be found in Appendix C - ED 3029 Calculation of Annual Peak Forecast Procedure.

Exhibit II-1 shows the historical and engineering forecast percent growth rate for the overall Eversource system and each geographic area. The Historical column shows the calculated percent growth rate based on historical recorded peaks. The Forecast column displays the percent growth rate used for planning purposes. The system loading observed in 2011 and 2013 rose to within 1.6% of the all-time peak established in 2006. 2011 was the last year with two consecutive 17 degree cooling days. The economic downturn which began in the fall of 2008 has resulted in a significant decline in the historical compounded annual growth rate.

Exhibit II-1: Eversource Summer Peak Load Forecast by Area

Area	2010-2014* Summer Peak (MW)	2014 Summer Peak (MW)	Compound Annual Growth Rate (%)		
			Historical	Forecast	
			2004-2014	2015-2019	2020-2024
Lakes Region	187.3 (2011)	182.0	1.2	1.5	1.25
Derry	122.7 (2011)	111.4	1.6	2.0	1.75
Dover/Rochester	175.2 (2011)	162.3	1.6	1.8	1.75
Manchester	380.6 (2011)	356.0	1.3	1.8	1.50
Sunapee	41.5 (2013)	39.7	1.0	1.2	1.00
Berlin/Lancaster	56.4 (2011)	50.4	-2.6	0.5	0.50
Portsmouth	262.2 (2013)	249.3	2.1	3.2	2.25
Nashua	397.9 (2013)	375.5	0.1	0.5	0.50
Western	173.2 (2010)	152.9	1.5	2.0	1.75
Conway/Ossipee	87.7 (2013)	80.8	2.4****	1.8	1.80
Seacoast	167.4 (2011)	151.9	1.3	2.3**	1.7**
Concord	131.5 (2013)	126.0	1.0	1.2**	1.0**
CVEC	32.1 (2011)	31.1	1.0	1.2	1.00
Eversource System *	**1920.6 (2011)**	**1768.3**	**0.9**	**1.3**	**1.00**

* Historical summer peak was 1952.2 MW set in 2006.
** Unitil provided loading forecast for these areas dated 9/24/2014. Growth rates were derived from the Unitil forecast.
*** Eversource system data includes former CVEC load as well as NHEC and municipal load served at the distribution level.
**** In 2010, approx. 5 MW was reassigned from Lakes Region to Conway/Ossipee.

B. Planning Use of the Engineering Forecast

System planning is performed for Eversource's main 34.5 kV distribution system by incorporating the engineering forecast loads into a computer model. Capital investment needs are identified in an annual system planning loadflow study. This study scales the system load annually according to the engineering forecast report. System overloads and operating constraints are identified for each year based on Company guidelines as detailed in ED-3002 Distribution System Planning and Design Criteria Guidelines which is included in Appendix D. Long-term solutions are developed by incorporating criteria such as good engineering design, reliability, aging equipment, power quality, and operating strategies. These guidelines provide the basis for least cost planning for the distribution system.

The annual system study is a ten-year forecast analysis identifying capacity needs for the distribution system based on Eversource procedure ED-3002. The first five years of the ten-year report are used for detailed short term planning and budgeting while the last five years of the report are used to identify longer term loading and system issues. The long term system issues are analyzed by the System Planning Department to determine what type of overall strategy for an area is best. In some cases, completing smaller projects over many years to address short and long term needs is chosen as the best option, and in other instances major system expansion is recommended. Many factors are included in determining the best option for correcting any problems that are identified and a decision matrix is used as a tool to identify and rank various solutions. Projects are ranked by using weighted criteria such as net present value, impact on reliability, operational impact, environmental impact, and system loss savings. Each criterion is considered for all proposed solutions at a challenge session and is scored based on its effectiveness. The cost-benefit analysis always carries the most weight. Opportunities to delay capital expenditures, including targeted conservation and load management and distributed generation, are included in the analysis and are discussed further in sections II-F and II-G.

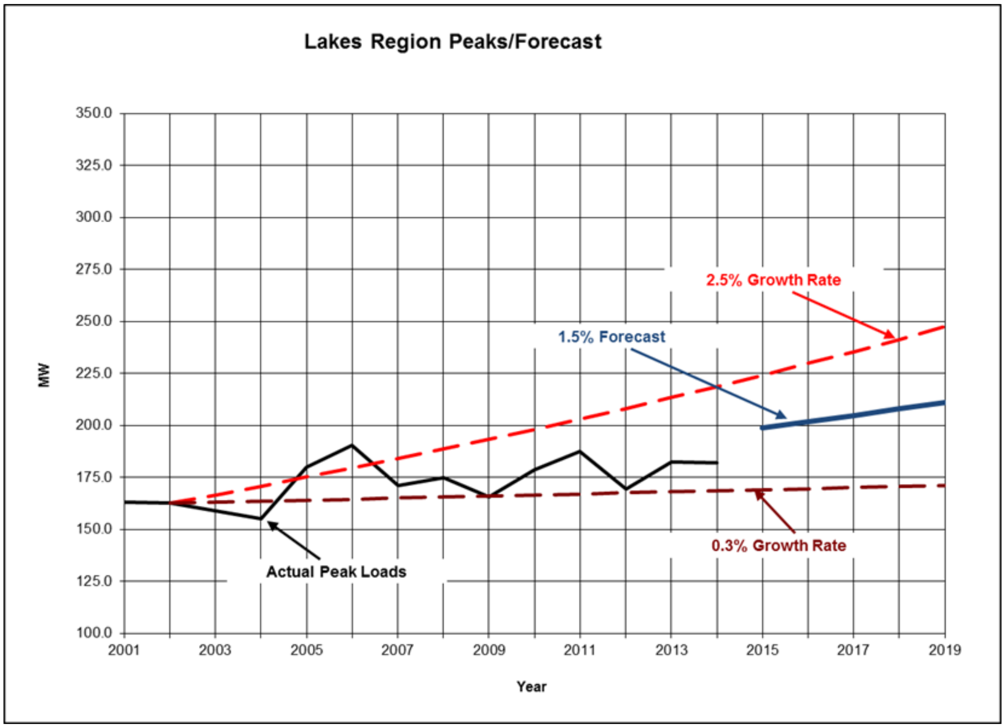
C. Planning by Area

The construction requirements for the electrical system are based upon each area's load growth and the area engineering forecast. Some areas experience peak demand growth rates that are higher than other areas and higher than the regional average, while other areas see essentially no peak load growth or even a reduction in peak load. Since additional distribution capacity may be required where the load growth is occuring, the planning process generally results in total system capital investment requirements that exceed what would be required if planning was simply performed based on Eversource's total system load growth. The summer peak demand history by area is shown in Appendix E. Although the protracted economic slowdown impacted all geographic planning areas, the Company is now seeing signs of future demand growth with a combination of new large manufacturing facilities, the addition of manufacturing at existing customer locations, commercial development, and customers taking electric service in place of existing diesel generation.

A discussion of each planning area and the corresponding engineering forecast is provided below.

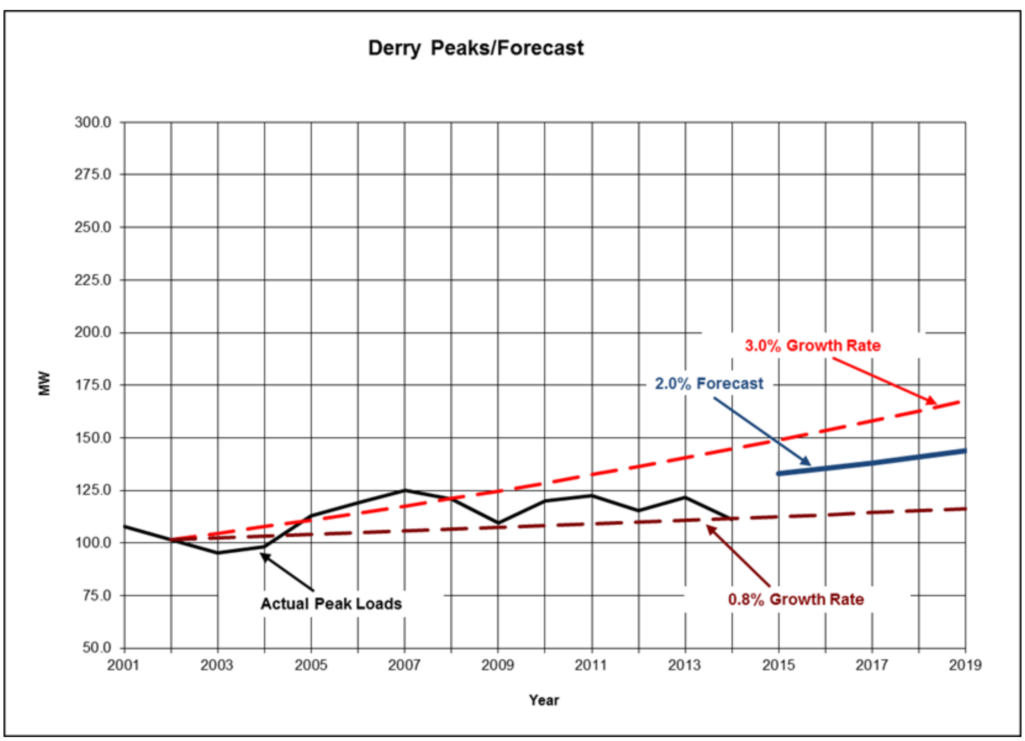
Lakes Region

Peak load in the Lakes Region has flattened since 2006. This area is expected to experience a modest 1.5% growth rate for the next five years.



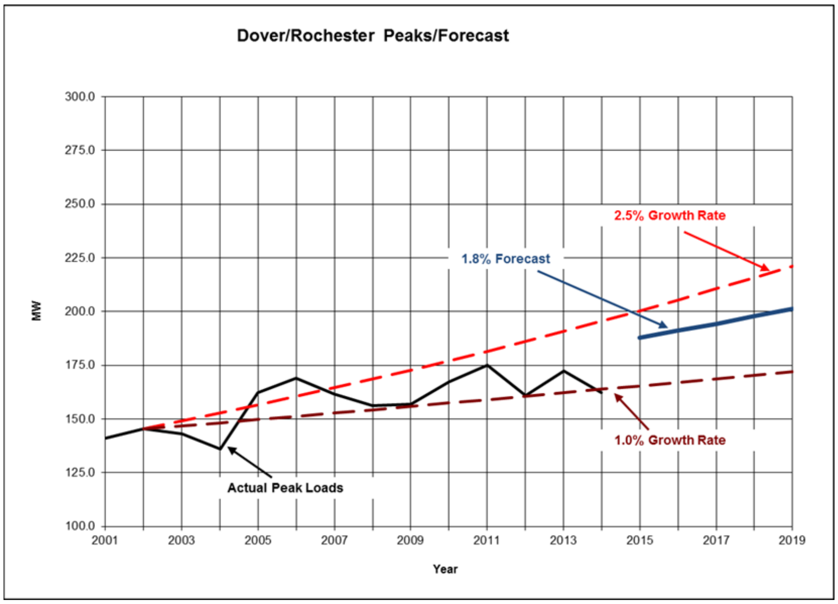
Derry

Load in the Derry region has been essentially flat since 2006. As the economy improves, the area is expected to have a growth rate of 2.0% for the next 5 years.



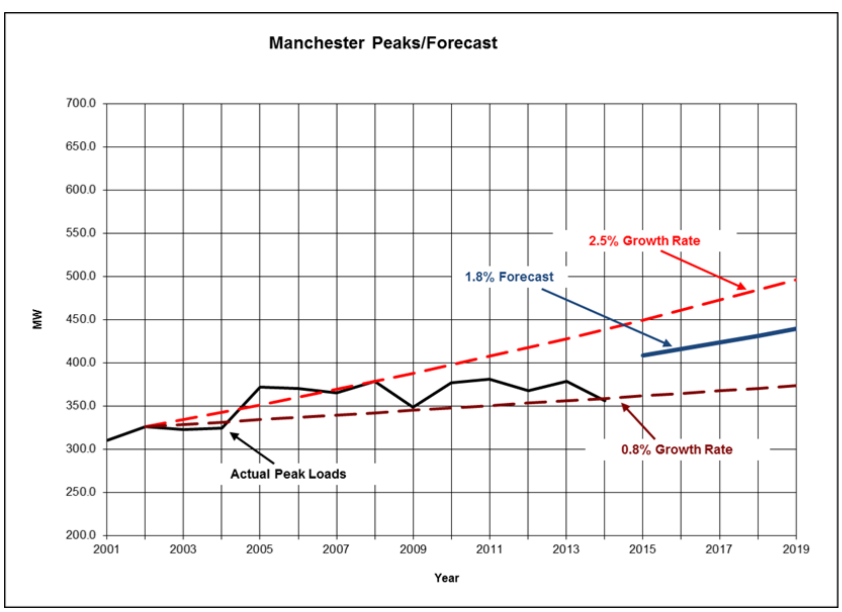
Dover/Rochester

The Dover/Rochester area experienced a peak in 2011 (the previous peak occurred in 2006). A major industrial customer in the area has constructed a new facility and has another building under construction. The facility had a 2014 peak usage of 1.1 MW and is expected to increase load in the area by an additional 5-7 MW over the next several years. Another large customer has relocated and built a new facility in the region. The facility had a 2014 peak usage of 2 MW. As new processes are added, the customer is expected to increase load by an additional 5-7 MW over the next few years. These increases in load are incremental to the 1.8% growth rate that is expected in the area.



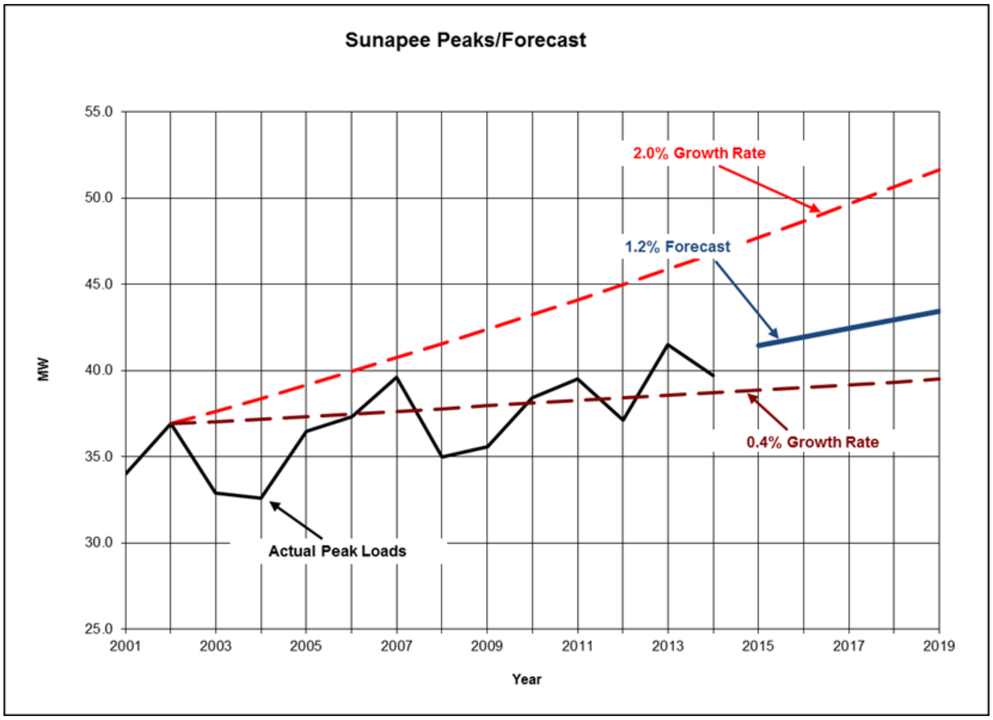
Manchester

Load has been essentially flat in the Manchester area since 2005. The improving economy is expected to result in a growth rate of 1.8% for the next 5 years. Completion of the airport access road has led to commercial/industrial construction with the potential to bring additional growth to the area. However, the closing of the Osram industrial facility in Manchester will offset some of this potential growth.



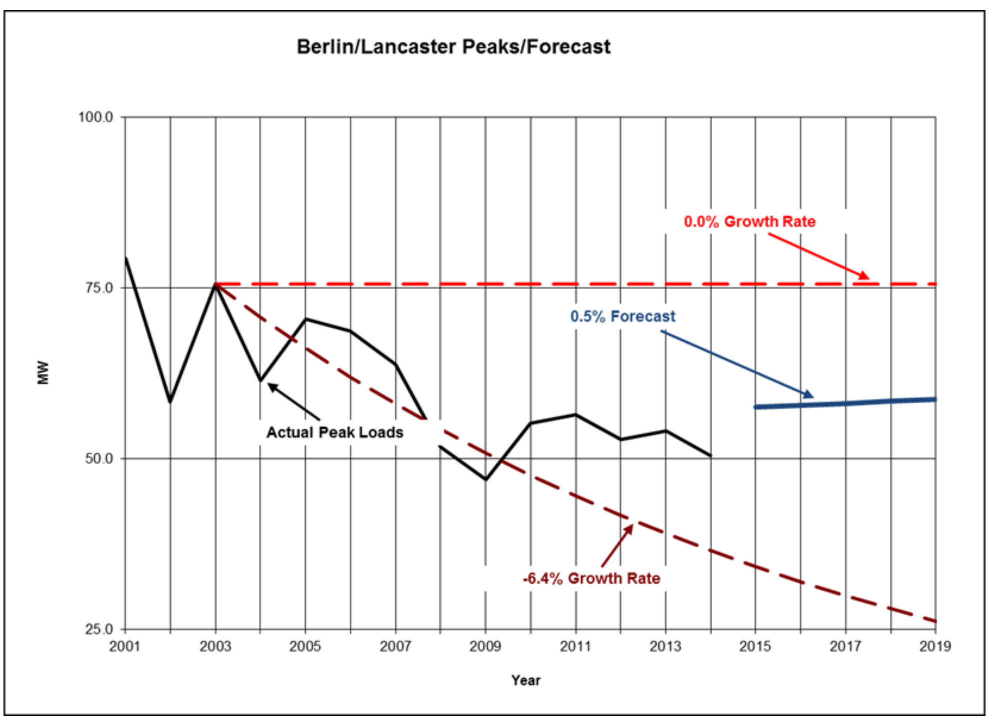
Sunapee

The Sunapee area peak load has flattened since 2006. This area is expected to experience a modest growth rate of 1.2% during the planning period.



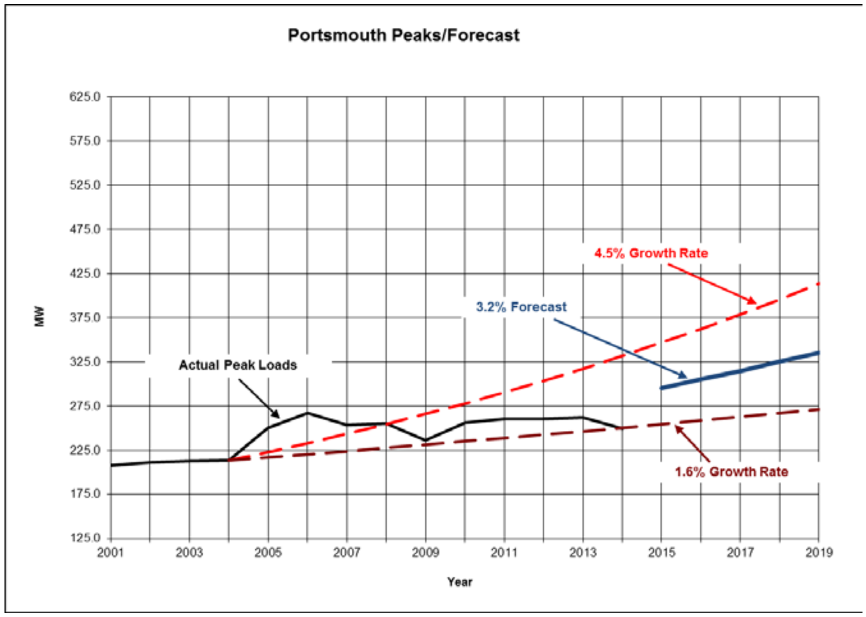
Berlin/Lancaster

Load dropped sharply in 2002, primarily caused by the closing of several paper and pulp mills. Load is expected to recover slightly due to the new federal prison in Berlin as well as the opening of a new generating plant. The forecast is 0.5% growth over the planning period.



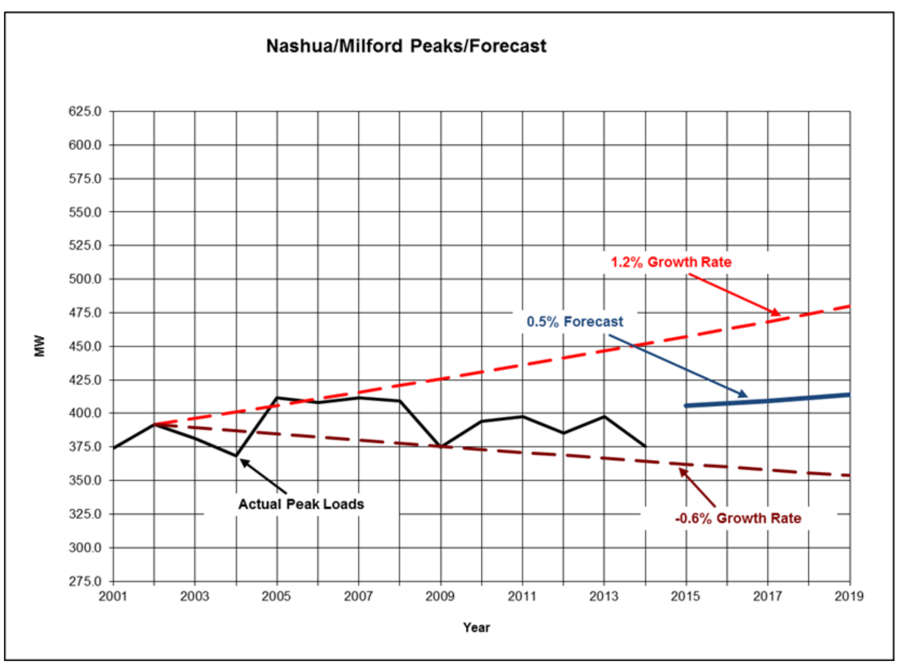
Portsmouth

Load in the Portsmouth area has recovered to 2006 levels, and it is expected to continue to grow at a rate of 3.2% over the next five years. The downtown area is being revitalized with the addition of new high end hotels. A major tenant of the Pease International Tradeport has expanded its facility and is expected to expand further. Another major manufacturer is also moving into a large facility in the Tradeport. Both expansions are expected to have a significant impact on the overall area load during the planning period.



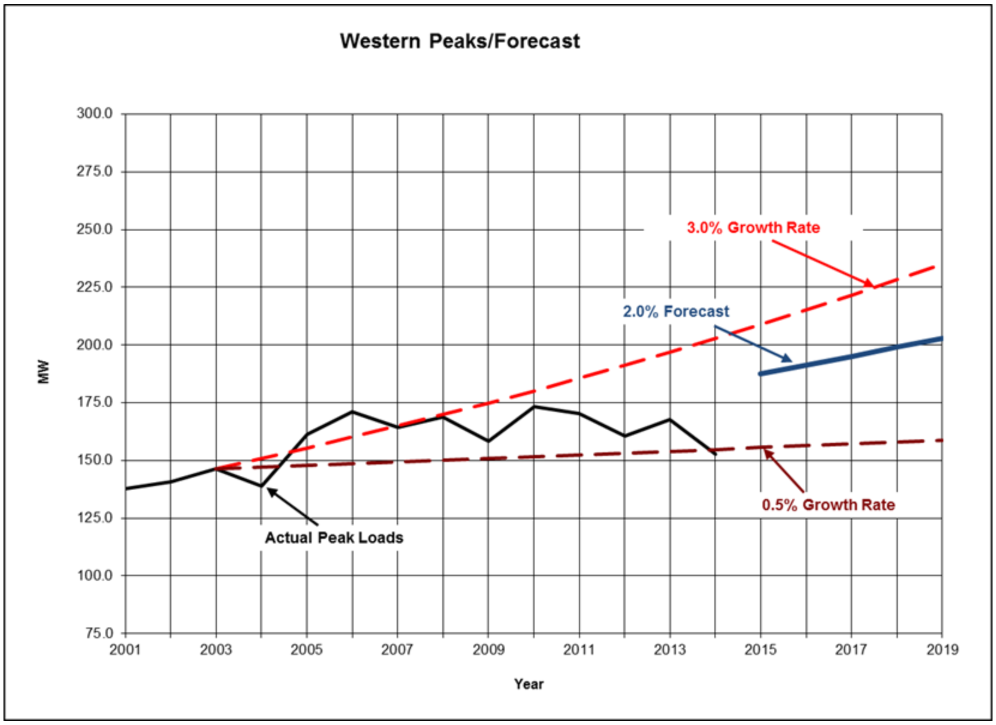
Nashua/Milford

The Nashua/Milford area load has decreased in recent years as a result of the loss of industrial customers (the area peak was set in 2005). The recent construction of the Merrimack Premium Outlets Mall and continued success of companies in the Nashua and Merrimack areas is expected to halt the decline in demand, with minimal growth expected in the coming years resulting in a 0.5% growth rate.



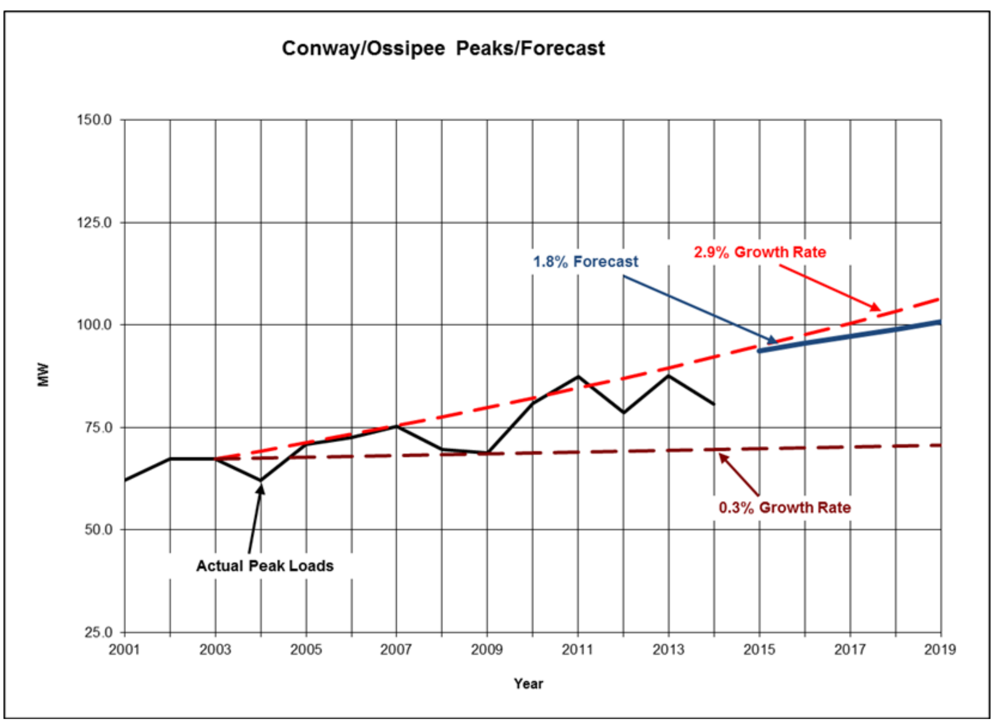
Hillsborough/Jaffrey/Keene

The Hillsborough/Jaffrey/Keene area reached a new all-time peak in 2010. This area is predominantly rural and is expected to experience 2% growth during the planning period.



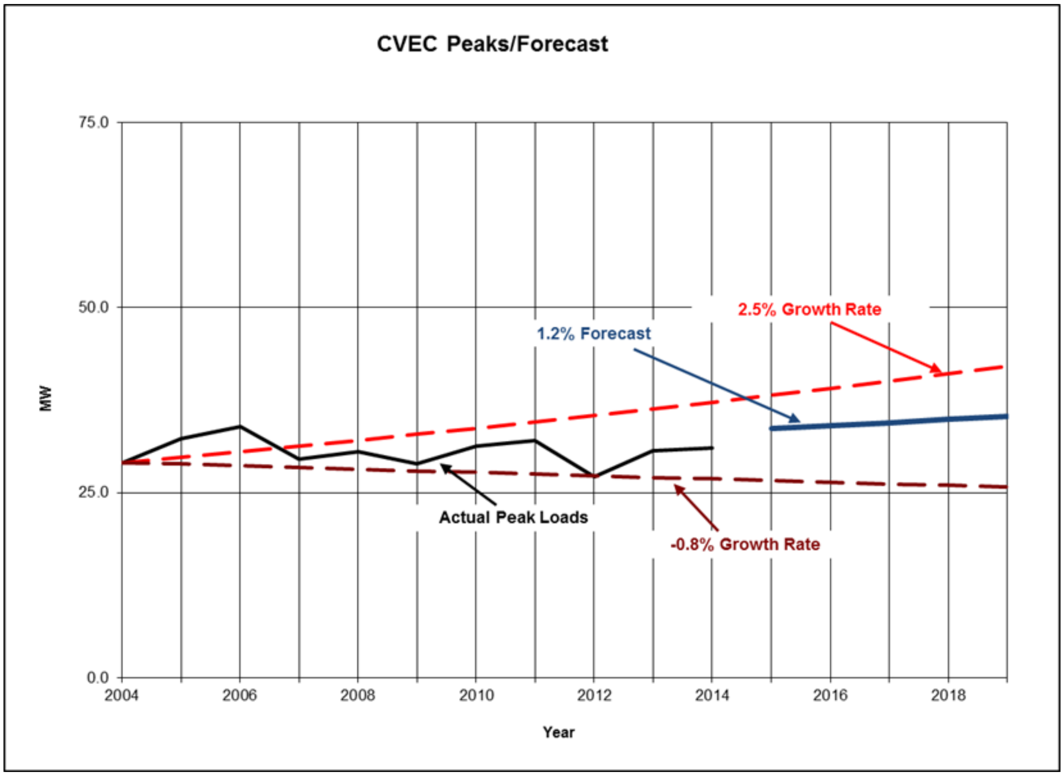
Conway/Ossipee

This area has a strong concentration of vacation homes and is a major tourist destination. The load increase seen in 2010 was a result of transferring New Hampshire Electric Coop's Melvin Village from the Lakes Region to the Ossipee Area, which added 5 MW to the area load. This area is expected to experience growth of 1.8% during the planning period.



Former Connecticut Valley Electric Company (CVEC) franchise area

The former CVEC area was acquired by Eversource in 2004. The area has not recovered to the demand levels experienced in 2006. A growth rate of less than 1.2% is expected.



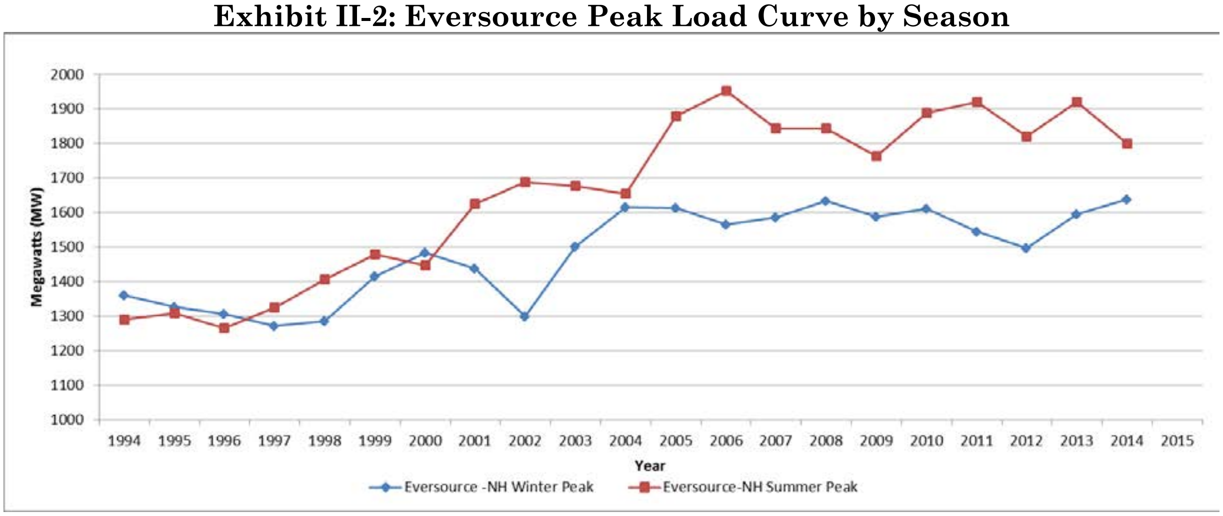
D. Joint Planning for Wholesale Delivery Service

Eversource participates in an annual review process for the integrated least cost planning of wholesale delivery facilities for the mutual benefit of New Hampshire electric distribution companies and their customers. This process is detailed in Eversource's procedure ED-3022[1] and is conducted with Unitil Energy Services ("UES") and the New Hampshire Electric Cooperative ("NHEC"). An Eversource - UES Joint Recommendations Report is generated each year. Eversource and NHEC meet periodically and perform joint planning when mutually agreed. (See section III.B, below).

E. Eversource Actual Peak Load Curves

Since 1997, with the exception of 2000, the Company has been a summer peaking utility as depicted in Exhibit II-2. This is primarily the result of the reduction in the use of electric heat and the increase in the use of air conditioning by customers. An increase in load related to residential air conditioning continues to be a significant factor.

Exhibit II-2: Eversource Peak Load Curve by Season

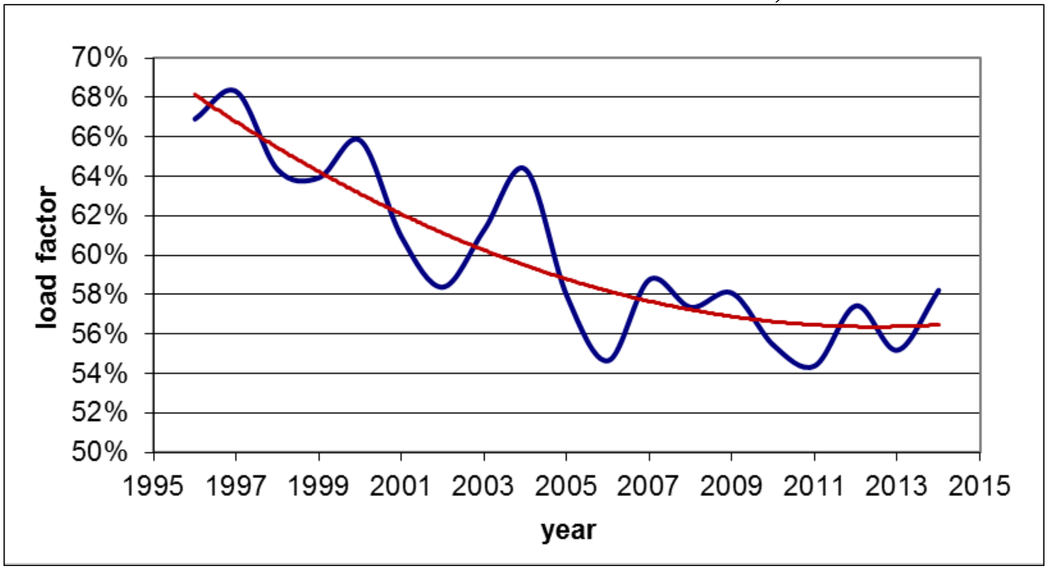


While the Eversource system peak of 2011 and 2013 nearly reached the all-time peak set in 2006, a number of planning areas have set new area peaks since 2006. These include Derry, Dover/Rochester, Manchester, Sunapee, Western, and Conway/Ossipee.

[1] ED-3022 was provided to the Commission's Staff in response to Question NSTF-02-020 in Docket No. DE 04-072.

Exhibit II-3 illustrates the Company's load factor from 1996 through 2012 and clearly shows a steady decline in load factor since 1996. The trend appears to have leveled off in recent years.

Exhibit II-3: Eversource Load Factor Curve, 1996-2014



The calculation for load factor is:

$$LF = kWh / (kW\ Peak \times 8{,}760\ Hours\ per\ Year)$$

The lowest values of load factor occurred in 2006 and 2011 and are attributed to low cost window air conditioning units coupled with elevated summer temperatures (cooling degree days of 21 on the peak day). This additional load created high peak demands, but relatively short operating times for the air conditioning units. Conversely, the warmest day in 2014 contained only 15 cooling degree days resulting in a relatively low peak demand and a corresponding higher load factor when compared to 2011, but still far below the load factors experienced prior to 2000. Moderate weather reduces air conditioning consumption during peak periods, which results in a lower demand during peak power consumption days. The lower load factors experienced in recent years have resulted in capital investments due to peak demand being required for fewer hours on an annual basis.

F. Conservation & Load Management Measures

Conservation and load management ("C&LM"), as a means of deferring capital expenditures needed to address forecasted peak demand, is addressed through Eversource's procedure TD190 – Targeted Application of C&LM Measures to Meet Peak Load Planning Needs which is included in Appendix F. System Planning, Field Engineering, and the Energy Efficiency teams meet annually to review proposed construction projects. Projects requiring a capacity savings of 1-5 MW with an estimated need date of approximately five years are evaluated by the Energy Efficiency team to determine if they are appropriate for targeted C&LM measures. Most projects proposed to address the growth of peak demand also provide reliability benefits and address aging infrastructure, which the C&LM measures do not address. Implementing targeted C&LM measures utilizing System Benefits Charge funds requires explicit Commission approval and must be initially performed on a pilot program basis. See Section IV for additional information on energy efficiency and demand response.

G. Distributed Generation

Distributed generation ("DG") includes the interconnection to Eversource's distribution system of: 1) Eversource owned large scale distributed generation; 2) seasonal application of mobile generation to address peak loads; 3) customer owned generation (behind a retail meter); and 4) independently owned generation (i.e., merchant generators). All requests to interconnect generation follows an application process administered by the Distributed Generation department.

Eversource has no plans to install large scale Company-owned DG at this time.

Eversource piloted the use of a seasonal mobile diesel generator to defer the construction of a substation and associated distribution line construction in the summer of 2010 and 2011 in New Boston. While this option may be considered in specific applications, the classification by the NH Department of Environmental Services ("DES") of the use of a mobile generator in New Hampshire as a "stationary" generator requires above ground storage tank permits, as well as emissions testing, reporting, and payment of fees. Operational stability and fueling challenges also need to be considered when determining the viability of this option as a short term solution.

Customer-owned generation consists of small scale renewable photovoltaic (PV) and wind, as well as a few natural gas, methane gas, and biomass fueled units. There has been a modest but growing amount of customer-owned photovoltaic (PV) installed in Eversource's territory. The small scale and intermittent nature of these systems results in a minimal impact to the planning process. As these systems go on-line, they become part of the historical trend and are assumed to continue to operate. Customer-owned DG for which the Company has an obligation to provide back-up service is accounted for when performing planning studies. A summary of net-metered generation is provided to the NHPUC each month in the form of the US Department of Energy form EIA-826.

Independently-owned generation interconnections to the distribution system consist of hydro, biomass, and wind generation. In recent years the majority of applications for interconnection have been proposals for wind generation. Wind generation is intermittent and therefore cannot be assumed to be available at the time of system peak in Eversource's planning studies. Hydro generation exhibits reduced output during the summer peak due to limited river flows. Biomass generation is assumed to be available for the base case model.

H. Smart Grid Investment

The Company has been investing in so-called "smart grid" initiatives since 2009. In general, 'Smart Grid' refers to the application of new technologies intended to bring the distribution system into the 21st century. These technologies include computer based remote operating platforms and devices, which, when coupled with two-way data communications systems, allow an electric utility to remotely operate its distribution system. This, in turn, can increase grid reliability, grid and customer efficiency, public safety, and overall system awareness.

2009 Smart Grid Pilot

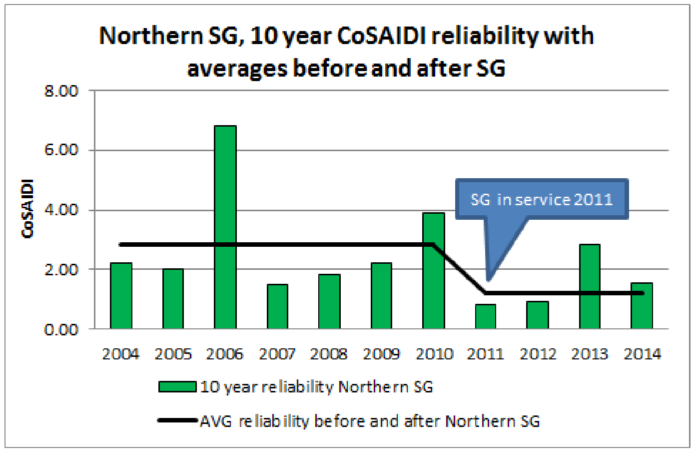
In 2009, Eversource issued an RFP for a Distribution Management System ("DMS") Pilot. The pilot program involved installing a DMS operating platform. More significantly, the DMS Pilot included the installation of field devices including advanced state-of-the-art reclosers with per phase sensing capability, microprocessor based relays, and data communications systems. These field device installations permitted remote analysis of the system by aiding in data acquisition in the form of per phase currents, voltages, power factor, and fault currents and targets. Proven through the DMS Pilot was the ability to remotely detect a fault which allows supervisory operation, from a remote location, to isolate a faulted section of line to smaller blocks of customers. This isolation process frequently allows the Company to restore power to some customers served from the circuit more rapidly than if the line did not have the DMS technology. There were three smart grid pilot regions, one in each of the existing operating divisions in the state, encompassing 5 bulk substations, and 11 open loop configured distribution circuits. Some of the details of the Smart grid program are:

	Customers impacted	Number of devices installed	Breaker relays upgraded
Seacoast Northern Division	7,057	11	
Southern Division	11,009	14	3
Western Division	11,736	15	2
Total	29,802	40	5

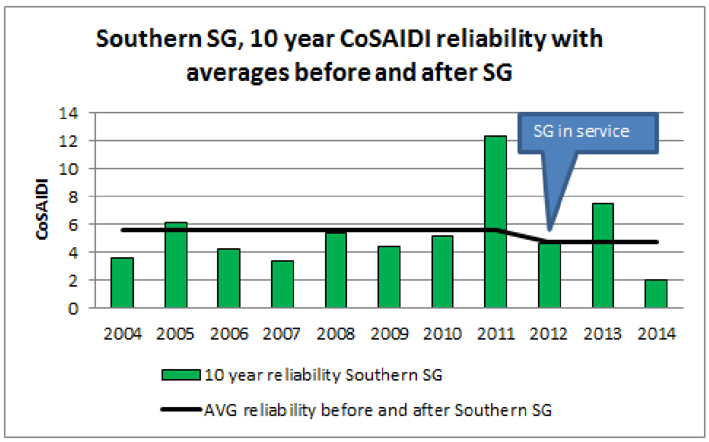
The deployment of the pilot took place by region over a four year period, first with the Seacoast Northern area in 2011, followed by the Southern region in 2012 and the Western region in 2014. Throughout the pilot, the distribution automation ("DA") design was analyzed and modified to yield the best results from a reliability and data acquisition perspective.

The reliability results achieved for each region are illustrated in the following charts:

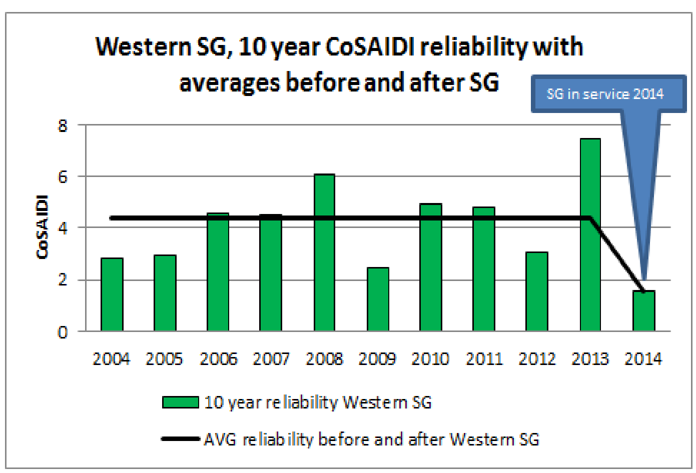
- Seacoast Northern region Smart Grid - Circuit's 333X, 333XS, 333XW, 347 circuit reliability yearly CoSAIDI performance and average performance before and after smart grid:



- Southern region Smart Grid - Circuit's 3128, 3133X, 365X 383X1 circuit reliability yearly CoSAIDI performance and average performance before and after smart grid:



- Western region Smart Grid - Circuit's 3128, 3133X, 365X 383X1 circuit reliability yearly CoSAIDI performance and average performance before and after smart grid:



As shown in the preceding charts, reliability has been positively impacted with the deployment of the smart grid pilot program. Eversource has recently reported a twenty-five percent increase in reliability performance with the application of distribution automation devices.

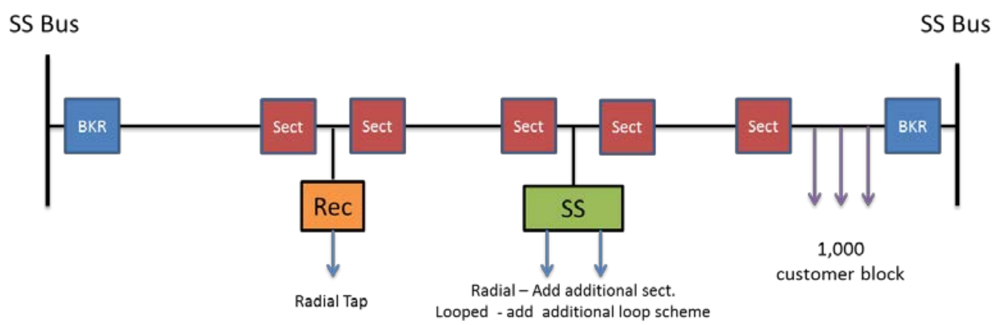
Future Distribution Automation (DA) deployment

In 2014, Eversource began a program to add additional DA to the entire distribution system in a proactive, methodical way. All circuits configured as open loop, closed loop, and radial will have devices installed in order to sectionalize the line remotely down to 1,000 customer blocks (at a minimum). In more rural areas, smaller customer blocks will be designed to account for the distances that are inherent in those areas. In addition, the DA deployment will include lower voltage class circuits. Historically, DA deployment has been limited to the 34.5 kV system, however, DA will now be installed on lower voltage circuits.

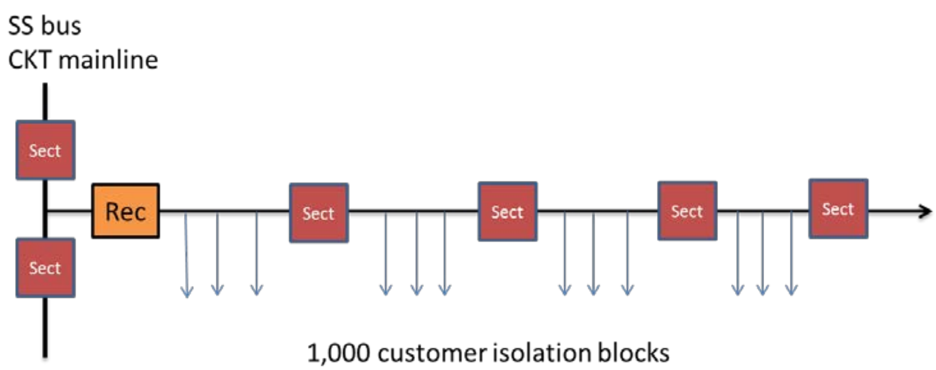
Below are block diagrams depicting how circuits are proposed to be segmented:

[BKR – Circuit Breaker, Sect – Sectionalizing Device, Rec – Recloser, SS – Substation]

- Open and closed loop circuitry DA designs:

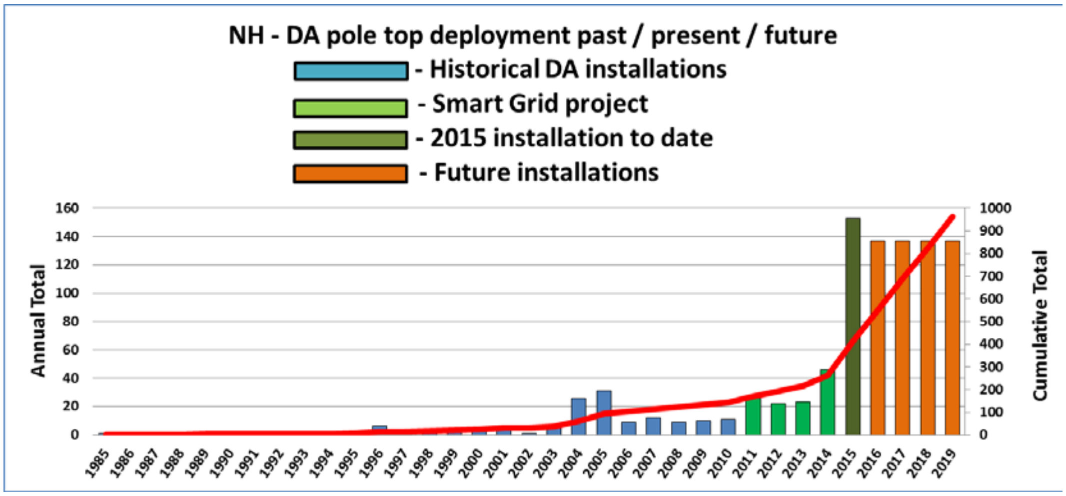


- Radial circuitry DA design:



The DA deployment is scheduled to occur over a five year term. At present, including YTD 2015 DA installations, Eversource has 378 pole top DA devices on its approximately 12,000 miles of distribution facilities. Of that amount, 230 have been added over the last five years. Below is a chart showing the historical and proposed future deployment of the DA design (once the project is complete Eversource will have greater than 800+ pole top DA devices on the system).

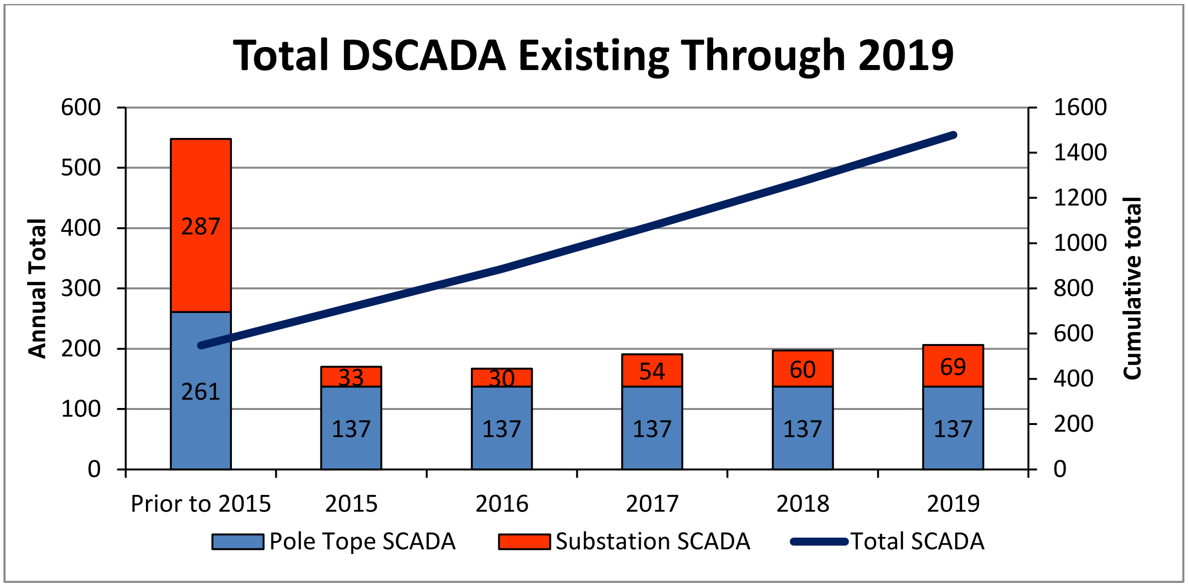
- Historical and future DA device deployment:



In addition to the pole top DA deployment, Eversource's plan calls for 50 relay upgrades and automation of all substations. The Company currently has 117 electromechanical relays. Under the DA program the Company will upgrade half of the relays to microprocessor based relays. These new relays will allow tighter protection coordination margins allowing additional protection points on the circuits, provide per phase electrical quantities for both real time and historical analysis, and allow more efficient system operations. The other half of the existing relays will be upgraded through various other projects outside the DA program.

Substation automation is also included as part of the DA plan. Eversource currently has forty-three 115-34.5 kV substations that are automated. These substations include 287 automated breakers, along with operations functions such as voltage control and voltage reduction. The DA plan includes automating the remaining substations which include eighty-four 12kV and 4 kV substations containing an additional 287 breakers and or reclosers. Automation of these substations will include control functions (open/close), status (open/close), voltage reduction, and per phase current measurements.

As of the end of the five year deployment, automation on the system will include nearly 1,500 units with remote oversight and control functions. Below is a chart depicting the deployment and the number of units to be installed each year:



Over time, reliability benefits should become increasingly evident, and operational efficiencies will be gained from these installations.

III. Transmission Planning and Investment

A. Regional Transmission System Planning Process

Ten-year transmission system planning is performed to develop a regionally coordinated plan to reliably meet customer demands for electricity in addition to supporting the delivery of power across the region. New Hampshire transmission facilities are needed for reliability and to support the expansion of the New Hampshire economy. As noted by the Commission in Order No. 25,459, PSNH's transmission requirements are considered within the purview of the ISO-NE regional transmission planning process. Eversource actively participates in the development of the ISO-NE RSP.

The regional transmission system planning process is performed in compliance with applicable planning standards of the North American Electric Reliability Corporation and the Northeast Power Coordinating Council Inc. The FERC has given authority to ISO-NE to operate and perform regional system planning of the transmission system in New England. The ISO-NE regional transmission planning process for the New England pool transmission facilities is performed in accordance with the ISO-NE Transmission, Markets, and Services Tariff (ISO-NE Tariff) Attachment K. This planning process is coordinated with transmission-owning entities, other entities interconnected to the New England transmission system, and the owners and planning authorities of neighboring systems to ensure the reliability of the New England transmission system and ensure compliance with national and regional planning standards and criteria. As described in Attachment K of the ISO-NE Tariff - Local System Planning Process, the Participating Transmission Owners (PTOs) are responsible for the Local System Planning (LSP) process for the Non-PTF of the New England Transmission System.

As part of the regional planning process, significant stakeholder input is afforded to ISO-NE by the Planning Advisory Committee (PAC). Specifically, the PAC reviews and provides input on: (i) the development of the RSP, (ii) assumptions for studies, (iii) the results of Needs Assessments and Solutions Studies, and (iv) potential market responses to the needs identified by the ISO in a Needs Assessment or the RSP. ISO-NE and New England Transmission Owners (TOs) conduct periodic assessment studies on a system-wide or specific-area basis (Needs Assessments) of the New England transmission system. This assessment is performed to identify system needs over a long-term planning horizon. ISO-NE incorporates market responses as the first step in meeting needs identified in the Needs Assessments. If market responses do not eliminate or address the needs identified in Needs Assessments, the ISO-NE develops and evaluates regulated transmission solutions in response to the needs identified by the ISO-NE.

When a system reliability need is identified from a Needs Assessment, ISO-NE begins a process to address the need. Prior to the May 18, 2015 start of New England's Order 1000 process, ISO-NE and the TO(s) developed transmission system alternatives to resolve the reliability need to ensure compliance with the national and regional reliability standards. ISO-NE and the TOs developed a report that identified and analyzed these potential solutions that were necessary to address the reliability needs (Solution Study). Starting May 18, 2015, ISO-NE decides whether it must conduct a competitive process to determine the solution. No matter which process is used, the transmission system alternatives are evaluated by ISO-NE to determine a preferred transmission "backstop" solution that is then presented PAC. In parallel, market participants can develop and propose market alternatives that would resolve the identified needs.

The centerpiece of the regional planning process is the ISO-NE development of the RSP. The RSP is published on an annual basis and contains the assumptions, methods and needs for the for the New England regional transmission system. The ISO-NE develops the RSP for approval by the ISO Board of Directors following stakeholder input through PAC. The RSP identifies: (i) PTF system reliability needs, (ii) the requirements and characteristics of the types of resources that may satisfy PTF system reliability and market efficiency needs to provide stakeholders an opportunity to develop and propose efficient market responses to meet the needs identified in Needs Assessments; and (iii) regulated transmission solutions to meet the needs identified in Needs Assessments where market responses do not address such needs or additional transmission infrastructure may be required to comply with national and regional planning standards, criteria and procedures or provide market efficiency benefits. In addition, the RSP also provides information on a broad variety of power system requirements that serve as input for reviewing the design of the markets and the overall economic performance of the system. The RSP also describes the coordination of the ISO-NE's regional system plans with regional, local and inter-area planning activities.

ISO-NE also develops, maintains and posts on its website a cumulative list reflecting the regulated transmission solutions proposed in response to Needs Assessments (RSP Project List). The RSP Project List is a cumulative representation of the regional transmission planning expansion efforts ongoing in New England. The project listing is periodically updated by ISO-NE to follow the progression of a project, beginning with conceptual designs under Needs Assessments, upgraded to a preferred solution following final PAC review of a Solution Study. The planned project status changes when the project is under construction. The final status is completed when the project is placed in service and designated as such in the project listing.

Another part of the stakeholder process is the review of project plans by the New England Power Pool (NEPOOL). Once the preferred transmission solution has been reviewed by PAC, the project is then analyzed in accordance with section I.3.9 of the ISO-NE Tariff. The project sponsor performs detailed engineering and power flow analyses that is the basis of a Proposed Plan Application (PPA) that is submitted to ISO-NE for review by NEPOOL and final approval by ISO-NE. This review is needed to ensure that a preferred project will have a no significant adverse effect on the stability, reliability, or operating characteristics of the TO's transmission facilities, the transmission facilities of another TO, or the system of a Market Participant in New England.

The transmission planning process is shown below in Exhibit III-1.

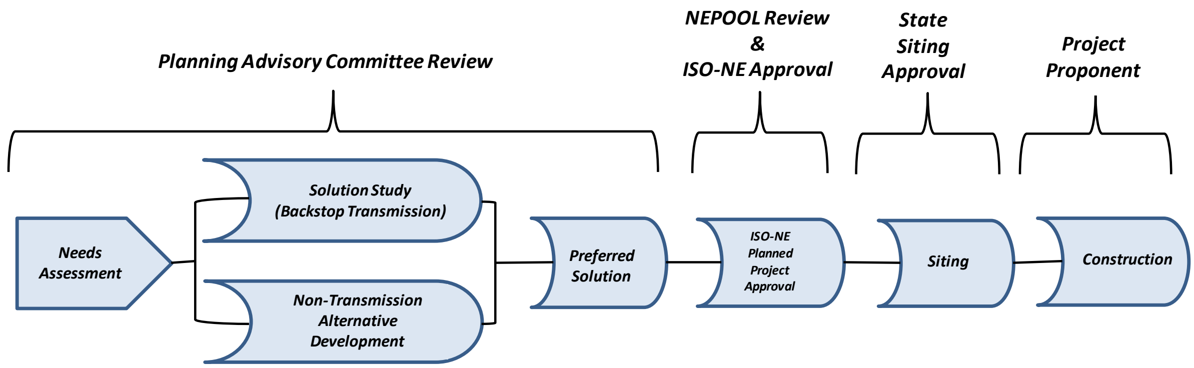


Exhibit III-1: ISO-NE Regional System Planning - Pre FERC Order 1000 Process

To comply with applicable regulatory requirements, Eversource's local transmission planning process employs methodologies similar to the ISO-NE regional planning process. The consideration and evaluation of multiple alternatives to address local reliability needs and the final development of a recommended local system plan are coordinated with ISO-NE as part of the overall regional planning process and the development of the annual ISO-NE RSP. This information is identified in the Eversource Local System Plan[2] (LSP) as presented to PAC on an annual basis.

B. New Hampshire Transmission Planning

The New Hampshire transmission plan is discussed in detail in the ISO-NE 2014 RSP (starting on page 91) and can be found at the following web site.

http://iso-ne.com/trans/rsp/index.html

The RSP notes that ISO-NE is taking action to address transmission system reliability issues in all six New England states and has developed preferred solutions to serve customer needs. The RSP specifically indicates that a number of studies of the New Hampshire system have been conducted. These studies have identified the need for additional 345/115 kV transformation capability and the need for additional 115 kV transmission support in various parts of the state.

Because Eversource's transmission requirements are within the purview of ISO-NE, the RSP should be consulted for a complete understanding of the New England transmission planning process.

[2] A copy of the Eversource 2014 Local System Plan can be downloaded from the Eversource web site at the following location: http://www.transmission-nu.com/business/pdfs/Local_Projects_List.pdf

IV. Demand-Side Energy Management Programs

A. Statewide CORE Energy Efficiency Programs

Introduction

Since 2002, New Hampshire has partnered with its electric and natural gas utilities to manage and administer the state's CORE Energy Efficiency Programs, also known as NHSaves. Energy efficiency is a central mission for Eversource, and is a key part of our strategy for building a modern and sustainable energy future. From 2002 through 2013, electric customers have saved over 10 billion electric kilowatt-hours over the life of the energy efficiency measures installed which translates into customer savings of more than $1.4 billion that can be reinvested in New Hampshire's economy. Eversource offers a suite of efficiency solutions designed to meet the varied needs of our customers – whether it is helping homeowners to retrofit and reinsulate their homes, helping businesses install high efficiency lighting systems or helping school districts install more efficient heating systems – our programs are making a difference. Some of the ways these programs benefit New Hampshire customers include:

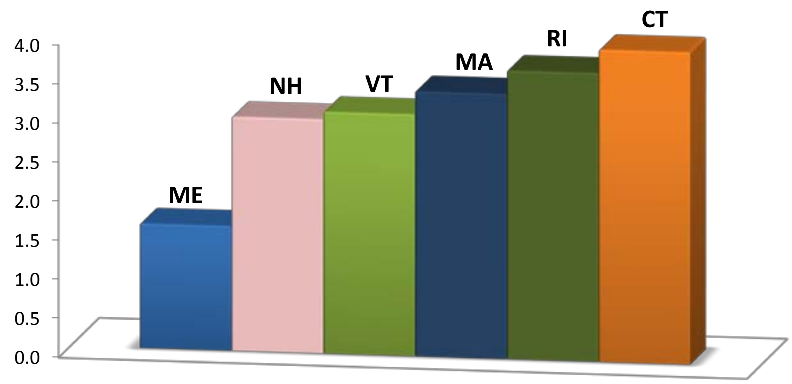
- Working with Home Energy Raters and private builders, our programs result in the construction of highly efficient homes using 15-20% less energy than a standard new home.
- Providing incentives so that existing homes can have insulation, air-sealing and other weatherization work performed by qualified private contractors to reduce a homeowner's heating costs by more than 15%.
- Income qualified customers can receive insulation, air-sealing and other weatherization work performed at no cost, saving them about $350 annually, through our collaboration with the NH Office of Energy and Planning's Weatherization Assistance Program and the Community Action Agencies around the state.
- Our appliance programs include over 100 retailers that help customers purchase highly efficient appliances using 10-20% less energy than standard models.
- Our lighting program encourages customers to purchase energy efficient light bulbs that use 75% less energy than standard incandescent bulbs while lasting 10-25 times longer (over 100 lighting retailers participate).
- Our business programs help businesses and non-profit agencies identify and install more efficient lighting, controls, motors, HVAC equipment, air compressors and industrial process equipment. These measures save energy and reduce energy costs, resulting in more money to invest in their businesses and agencies.
- A special focus on municipalities which helps to save energy in public buildings, reducing overall costs to taxpayers.

In addition to the direct beneficial impact on customers, the programs also benefit New Hampshire by:

- Reducing New England's peak load – in 2013 New England's peak load was reduced by 8.3 MWs as a result of the statewide programs; the equivalent peak load of approximately 5,500 residences.
- Reducing emissions – equivalent to taking 1.3 million cars off the road for a year.
- Creating jobs – 338 jobs were supported by the programs in 2013.

In addition to providing significant benefits, these programs are also a cost-effective solution to helping meet the region's overall electrical energy needs. As illustrated below, all of the New England states, including New Hampshire, deliver cost-effective energy efficiency programs – attaining greater kilowatt-hour savings for every dollar spent on energy efficiency than the retail cost (14.37 cents)[3] to purchase the energy.

Cost to Save a Lifetime kWh
Source: ISO-NE's Energy Efficiency Forecast dated 5/1/2015
(cents/kWh)



The programs have continued to evolve over time in response to new technologies, market conditions, program evaluations and new standards. Most recently, Eversource is leveraging the private financing market in New Hampshire to support increased investment in energy efficiency by implementing an energy efficiency financing option through local financial institutions. In addition, Eversource has initiated a Home Energy Reports program where residential customers receive personalized energy savings reports that include information about the electric usage in their home and tailored tips and recommendations to motivate customers to change their behavior and take action to save energy. In 2015, Eversource is excited to launch its Customer Engagement Platform ("CEP") in New Hampshire. This platform is an interactive tool that will allow Eversource to effectively reach all of its customers with energy usage information that is tailored to each customer and situation. It will include self-service efficiency assessments as well as benchmarking, which will allow business and residential customers to track energy use over time and compare their usage with similar customers in their geographic area and customer segment. Customers will learn about solutions that will save energy and reduce costs in addition to receiving information about incentives, which will increase their willingness to make efficiency improvements.

Along with these three recent examples, Eversource is confident the CORE Programs can be expanded to accommodate any cost-effective electric energy saving technology of interest to our customers; and, with adequate funding, is ready to scale up the level of energy efficiency programs and services offered to our customers to work towards meeting the available energy efficiency potential in the state.

[3] Based on NH Office of Energy and Planning's average electricity price effective June 1, 2015.

Impact of the CORE Programs on Energy Consumption

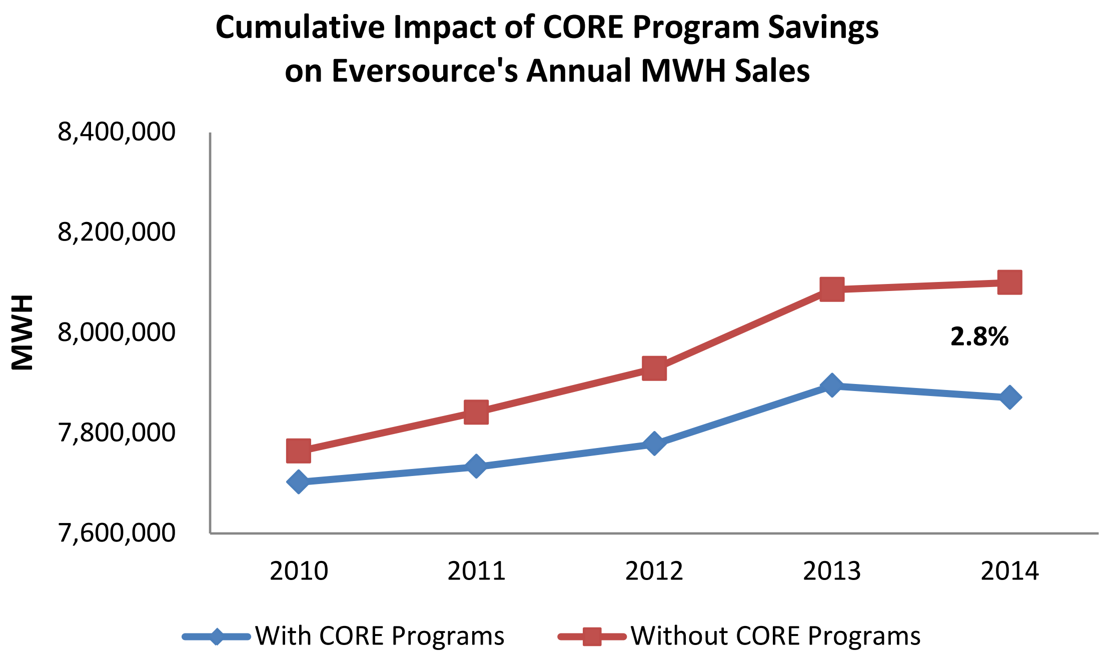
Table IV.1 below summarizes Eversource's actual expenditures, lifetime kilowatt-hour savings, annual kilowatt-hour savings and customer participation during the 2014 program year by customer sector and program. Based on the 2014 results, Eversource saved kilowatt-hours at an average cost of 3.0 cents[4] per lifetime kilowatt-hour as compared to the current average retail price per kilowatt-hour of 14.37 cents. This represents a simple benefit ratio on program investment of almost 5:1.

Table IV.1: 2014 CORE Programs Results

	Expenditures	Lifetime kWh Savings	Annual kWh Savings	Customer Participation
Residential				
Home Energy Assistance	$ 2,805,621	11,067,572	657,200	637
Home Performance with ENERGY STAR	$ 2,280,382	12,359,149	728,828	1,094
ENERGY STAR Homes, including Geothermal	$ 1,256,265	39,211,190	1,614,448	449
ENERGY STAR Products	$ 3,265,233	88,130,787	7,160,293	73,647
Home Energy Reports	$ 126,282	1,426,974	1,426,974	25,000
Forward Capacity Market Reporting	$ 28,590	-	-	-
Residential Total	$ 9,762,374	152,195,672	11,587,744	100,827
Commercial and Industrial				
Large Business Energy Solutions	$ 5,023,029	330,149,718	24,267,051	358
Small Business Energy Solutions	$ 2,604,476	111,977,704	8,737,183	889
Municipal	$ 1,081,377	56,922,373	4,327,828	163
RFP Program	$ 361,981	43,325,524	2,968,970	11
Education	$ 173,673	-	-	90
SmartStart	$ 30,270	-	-	-
Partnerships	$ 9,287	-	-	1
Forward Capacity Market Reporting	$ 66,711	-	-	-
Commercial and Industrial Total	$ 9,350,804	542,375,319	40,301,032	1,512
Overall Total	**$ 19,113,178**	**694,570,991**	**51,888,776**	**102,339**

[4] The calculation includes a performance incentive of $1.77 million.

The 2014 annual kilowatt-hour savings are approximately 0.66% of Eversource's total billed delivery kilowatt-hour sales in 2014 (51,888,776 / 7,906,557,000). The average life of the installed energy efficiency measures is 13.4 years. As a result, the savings associated with the measures installed in 2014 will continue well into the future and the cumulative impact of the programs will become more significant over time. As illustrated in the chart below, the cumulative impact of the CORE Programs over the past five years has resulted in a cumulative decline of delivered MWH sales of 2.8% in 2014.



Impact of the CORE Programs on Capacity or Peak Reduction

In addition to the kilowatt-hour energy savings, the CORE Programs also provide capacity or peak demand reductions. Table IV.2 summarizes the average annual capacity reduction coincident with the New England peak resulting from operable CORE Programs efficiency measures installed by customers between June 16, 2006 and May 31, 2014. As shown, the CORE Programs implemented by Eversource reduce New England's peak load, which currently occurs in the summer, by 6.2 MWs, which is approximately 0.35% of Eversource's system peak load in New Hampshire (6.2 / 1,768.3).

Table IV.2: CORE Programs Capacity Reduction Based on Operable Measures Installed Between June 16, 2006 and May 31, 2014

	Coincident with ISO-NE Peak	
	Summer kW	Winter kW
Residential		
Home Energy Assistance	693.6	1,580.3
Home Performance with ENERGY STAR	505.8	1,628.8
ENERGY STAR Homes, including Geothermal	267.2	3,370.5
ENERGY STAR Lighting	3,502.7	12,667.2
ENERGY STAR Appliances	1,684.0	2,005.8
Residential Total	6,653.3	21,252.6
Commercial and Industrial		
Large Business Energy Solutions	26,004.1	20,084.5
Small Business Energy Solutions	15,529.3	10,686.3
Municipal	11.7	48.9
RFP Program	1,432.9	1,311.0
Commercial and Industrial Total	42,978.0	32,130.7
Overall Total	49,631.3	53,383.3
Average kW / Month (95.5 Months in Period)	519.7	559.0
Annualized Capacity Reduction	**6,236.4**	**6,707.8**

The four New Hampshire electric utilities, including Eversource, are the only energy efficiency providers in New Hampshire participating in ISO-NE's forward capacity market. The proceeds obtained through participation in this market have totaled $9 million from 2007 through 2014. These proceeds are utilized as a funding source for the CORE Programs, and represent approximately 11% of Eversource's 2015 electric CORE Programs budget. In order to qualify for payments from ISO-NE, Eversource must certify to ISO-NE's satisfaction that the capacity reductions are operational during hours of peak electrical usage. Eversource has developed the necessary reporting and measurement and verification plans needed to evaluate the impact of the efficiency measures at the time of the New England peak and the resulting capacity reduction load value that qualifies for payment from ISO-NE. Eversource has met the rigorous reporting standards and requirements to participate in the forward capacity market. As a result, the estimated capacity reductions summarized above are an accurate representation of the capacity reductions resulting from the CORE Programs as they have been thoroughly reviewed by ISO-NE and independently certified.

Energy Efficiency Measures and Initiatives Recently Implemented to Reduce Energy and Capacity

Market Assessment Study of Air Conditioning Equipment
Eversource, in conjunction with the Commission's Staff and the other New Hampshire electric utilities, contracted with The Cadmus Group to complete a market assessment study of air conditioning equipment in the residential and commercial/industrial sectors. On April 5, 2013, the New Hampshire electric utilities filed a final report entitled "New Hampshire HVAC Load and Savings Research" with the Commission. This research studied the drivers of the increasing air conditioning load in both the residential and Commercial/Industrial sectors; recommended additional measures to reduce air conditioning electric loads and provided estimates of the ancillary electric savings associated with various non-electric measures utilized in the Home Performance with ENERGY STAR Program.

With respect to air conditioning impact on the ISO-NE "On Peak Hours", the research found that air conditioning loads contribute to the demand for electricity during on peak hours in New Hampshire. Cadmus recommended several cooling measures be included in the CORE Programs to enhance energy and peak demand reductions. As a result of this research, Eversource has included incentives within the CORE Programs for high efficiency ENERGY STAR central air conditioning and air source heat pumps, high efficiency ductless mini-split heat pump systems which provide heating and air conditioning, and Wi-Fi thermostats. These measures have been added to both the Residential and Commercial/Industrial sectors. In addition, Eversource offers incentives on ENERGY STAR room air conditioners, variable speed drives for ventilation and other equipment, and encourages replacement of inefficient HVAC equipment in existing buildings and the highest efficiency equipment in new construction.

In addition, the research quantified the ancillary electric savings from non-electric energy efficiency measures, such as weatherization. Eversource has included the electric energy savings associated with the ancillary measures in its CORE Programs savings estimates. Specially, the ancillary measure savings associated with weatherizing homes include: boiler circulator pump savings, furnace fan savings, furnace with new ECM motor savings, central AC savings, and room AC savings.

Lighting Incentives Now Focus on LEDs
Eversource is transitioning from lighting incentives on CFLs to lighting incentives primarily on LEDs to support the transition to this new technology in both the residential and commercial/industrial sectors. The energy savings associated with LEDs is higher than CFLs, and the life expectancy of LEDs is longer than that for CFLs, which will lead to greater overall energy savings.

Marketing Campaign to Customers Likely to Utilize Electric Space Heating
In addition to giving priority to customers who heat their homes with electricity in the Home Performance with ENERGY STAR program, Eversource conducted a direct mail marketing campaign to customer segments identified as likely users of electric heat based

on their monthly usage characteristics. Three separate mailings, each targeting a different group of customers, took place over the period November 2013 – June 2014. This campaign resulted in 67 additional electrically heated homes enrolling in the program, of which 41 have completed energy efficiency home improvements-to-date.

The average annual kilowatt-hour savings associated with electrically heated homes is approximately four times higher than the average annual kilowatt-hour savings associated with non-electrically heated homes. These homes would likely not have been weatherized absent this marketing campaign. Although only a small percentage of customers utilize electricity to heat their homes in New Hampshire, Eversource will continue to prioritize these customers in the Home Performance with ENERGY STAR Program.

CORE Programs as a Demand-Side Resource

The CORE Programs implemented by Eversource saved approximately 694 million lifetime kilowatt-hours in 2014 at a total cost of $19 million and the operable energy efficiency measures installed between June 2006 and May 2015 reduced New England's peak load by 6.2 MWs each year. The average life of the energy efficiency measures installed in 2014 is 13.4 years, which means the cumulative energy savings of the CORE Programs grows over time as more energy efficiency measures are installed. As shown in Table IV.3 below, the forecasted New Hampshire load growth percentage would be approximately 23% higher (1.6% versus 1.3%) without the 2014 CORE Programs energy efficiency measures alone:

Table IV.3 - Estimated Overall Impact of 2014 CORE Programs on Projected Load Growth

(A) Eversource-NH System Peak MW (2010-2014)	(B) Forecasted Load Growth % (2015-2019)	(C) (A) x (B) Forecasted Load Growth MW (First Year)	(D) (A) + (C) Forecasted System Peak With CORE Programs (MW)	(E) System Peak Savings From CORE Programs (MW)	(F) (D) + (E) Forecasted System Peak Without CORE Programs (MW)
1,920.6	1.3%	25.0	1,945.6	6.3	1,951.9
		Load Growth %:	1.3%		1.6%
			% Difference in Load Growth:		23.1%

Although difficult to specifically quantify, system-wide, comprehensive energy efficiency programs, like New Hampshire's CORE Programs, can lead to deferrals of specific T&D investments over time whose need is driven by economic conditions and/or growing peak loads. Investments related to aging infrastructure, equipment failure or reliability, which represent the majority of the current investment, are generally not impacted by energy efficiency programs. As noted in the Northeast Energy Efficiency Partnerships ("NEEP") report entitled "Energy Efficiency as a T&D Resource"[5] "Passive deferrals, almost by definition, will occur to some degree in any jurisdiction that has system-wide efficiency programs of any significance. However, the degree and value of passive deferrals will obviously be heavily dependent on the scale and longevity of the programs. The benefits may be modest, deferring a small number of planned investments a year or two. They can be also quite substantial." Since the electric CORE Programs have been in place for thirteen years and the overall cumulative savings from the programs have been relatively

[5] Page 12, NEEP Report "Energy Efficiency as a T&D Resource", January 9, 2015. Available at: http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

significant, some planned capital investments have likely been deferred for a year or two over time as a result of the CORE Programs implemented by Eversource.

As compared to other demand-side resources, once energy efficiency measures are installed they do not require periodic renewal of customer participation agreements or ongoing customer incentive payments. In addition, the claimed capacity reductions are always "in service" during the life of the measures and do not depend upon Eversource's staff, customer personnel, or communications equipment for activation. As a result, the CORE Programs measures are a highly reliable demand resource.

Consideration of Geographically Targeting the CORE Programs

As summarized in Section II.F, on an annual basis Eversource's System Planning & Strategy and Energy Efficiency teams review a list of distribution system capital projects anticipated to be completed within a five year period and determine the feasibility of targeting Eversource's existing energy efficiency programs to the geographic area which will be served by the upgraded distribution system infrastructure. To-date, Eversource has not identified a distribution system capital project that could feasibly be deferred by geographically targeting its existing energy efficiency programs.

This result is similar to Eversource's experiences to-date with geographically targeting its energy efficiency programs in Massachusetts and Connecticut. In 2008, Eversource implemented a pilot program to attempt to reduce peak demand in Marshfield, Massachusetts by approximately 2 MW in order to alleviate overloaded and nearly overloaded circuits. This pilot program utilized solar panels, direct load control, and energy efficiency measures to attempt to achieve the targeted reduction. However, only 35% of the targeted reduction was attained. Achieving geographic specific peak load reductions from energy efficiency can be difficult depending on site specific characteristics. Energy efficiency programs, like the CORE Programs, are most effectively deployed over a broad based geographic area, over a long time period, and across different customer types. Utility experiences in geo-targeting energy efficiency programs to avoid or delay the need for a transmission or distribution investment to date have reflected these difficulties. According to the NEEP report referenced above, "Several of the geographic targeting projects that have occurred to date have found that the availability of savings was different from their initial expectations because their assumptions about the customers in the targeted areas were found to have been inaccurate. …contractors weren't able to meet their savings targets in the later years of their initial geo-targeting efforts and attributed this to the lack of a detailed understanding of the types of customers and predominant end uses in the targeted areas."[6]

As approved by the Commission in Docket 14-216 - 2015/2016 Statewide CORE Energy Efficiency Plan, and as noted above, Eversource has recently implemented a Customer Engagement Platform ("CEP") in Massachusetts and Connecticut and will soon be implementing the platform in New Hampshire[7]. In addition to providing customers with energy usage information that is tailored to them and their situations, the CEP will provide easy, intuitive and accessible resources and tools for customers to engage in transactional activities, informational searches on efficiency measures, and will allow Eversource to

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[6] Page 59, NEEP Report "Energy Efficiency as a T&D Resource", January 9, 2015. Available at: http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

[7] Pages 66-70, 2015/2016 Statewide CORE Energy Efficiency Plan, as revised on December 11, 2014 and submitted on December 15, 2014 in Docket No. DE 14-216.

develop a better understanding of customers, leading to improved targeting of energy efficiency products and services. Understanding the energy efficiency opportunities that may be available within a defined area, will lead to more accurate estimates of savings potential, which will lead to a greater level of confidence when reviewing proposals for geographically targeted energy efficiency programs or services in the future. Eversource plans to continue to monitor planned distribution system capital projects on an annual basis and determine the feasibility of geographically targeting Eversource's energy efficiency programs.

Legislative Guidance

While considering the CORE Programs as a demand resource, thought must be given to the guidance provided by the New Hampshire legislature in the Restructuring Policy Principles (RSA 374-F:3,VI) and Electric Utility Restructuring Implementation (RSA 374-F:4,VIII (e)). RSA 374-F:3,VI states, in part, "Benefits for all Consumers. Restructuring of the electric utility industry should be implemented in a manner that benefits all consumers equitably and does not benefit one customer class to the detriment of another. Costs should not be shifted unfairly among customers." Eversource interprets this to mean that the revenue collected from the energy efficiency portion of the system benefits charge be allocated to customers essentially in proportion to the amount of revenue collected from each customer class (Residential and Commercial/Industrial). Therefore, although shifting program funds to the Commercial/Industrial customer class may result in greater kilowatt-hour savings per dollar spent based on the current average cost to save a lifetime kilowatt-hour for each class, this type of allocation may not be consistent with current state law.

RSA 374-F:4,VIII (e) states "Targeted conservation, energy efficiency, and load management programs and incentives that are part of a strategy to minimize distribution costs may be included in the distribution charge or the system benefits charge, provided that system benefits charge funds are only used for customer-based energy efficiency measures, and such funding shall not exceed 10 percent of the energy efficiency portion of a utility's annual system benefits charge funds. A proposal for such use of system benefits charge funds shall be presented to the commission for approval. Any such approval shall initially be on a pilot program basis and the results of each pilot program proposal shall be subject to evaluation by the commission." Accordingly, and as noted in Section II.F., explicit Commission approval is required before SBC funds may be used on targeted C&LM as "part of a strategy to minimize distribution costs."

Demand Response Program

Beyond the CORE Programs, Eversource continues to administer the **HEAT**SMART demand-side management program which, if called upon during peak load conditions, has the potential to help reduce system demands. The **HEAT**SMART program operates on a system-wide basis and is not designed or intended to target a particular geographic area or individual distribution circuit. The program offers residential and small commercial customers a discounted delivery rate in exchange for allowing Eversource to curtail their usage using a radio controlled signal sent to equipment installed at the customer's premises. **HEAT**SMART is primarily designed to help control winter peak demands, and is most often initiated by ISO-NE Operating Procedure No. 4 (OP-4, Action During a Capacity Deficiency), Action 2, but can also be initiated by an Eversource dispatcher from the Company's Electric System Control Center ("ESCC"). It should be noted that during 2014 Action 2 was not implemented to curtail peak load. The program is available to curtail peak load year-round, and the interruptible load is electricity used for space heating (and cooling if using a heat pump) and water heating. These loads are metered and billed separately from other electricity on a non-demand, kilowatt-hour only rate. As of January 15, 2015, there were 4,143 customers on **HEAT**SMART. The Company's primary methodology for determining load and customer information for customers under the program is through a data form completed by **HEAT**SMART electricians. Based on this information, approximately 36% of the **HEAT**SMART customers are utilizing an electric thermal storage (or ETS) device and 64% are on the dual fuel option, utilizing either wood or coal as their backup heating source. Applying an average 18.5 KW and 24.9 KW connected load for residential and commercial customers respectively, Eversource estimates total connected load for all 4,143 customers to be approximately 78 MW.

In exchange for receiving the lower HEATSMART rate, Eversource can interrupt **HEAT**SMART load for up to four hours at a time, or up to a total of eight hours in any 24-hour period. An interruption would not affect lighting and other usage. However, no single interruption would exceed four hours in duration and the time between consecutive interruptions would be no less than 2 hours. Interruptions will not occur more than five times in a month and no more than 26 times in a year.

V. Appendix A – Process Narrative and Process Flow Diagram

The Eversource process of system planning and achieving the objectives of "Least Cost Planning" generally consists of four major stages. These stages include: 1) the gathering of historical loading, equipment, and reliability data; 2) preparing the forecast for peak electric demand; 3) evaluating the alternative solutions to projected overloads or operating violations; and 4) determining the load driven, aging infrastructure, and reliability projects that will be supported by the capital budget. Each of these stages is identified in Appendix B, System Planning Process Flow. Individual step inputs and outputs, Eversource personnel responsible, and a corresponding timeline are noted on the process flow diagram. Each process step is noted with a letter for easier reference to the process flow diagram.

1) Historical Loading/Reliability

a) The 34.5 kV interconnected system, which is also the portion of the system controlled by the Electric System Control Center ("ESCC"), is modeled and studied by the System Planning department. The system peak hour demand is provided by the Load Settlement department. While this information provides an overall picture of the load served by Eversource, the Eversource distribution system is divided into thirteen separate areas for study. Loading data from circuit breakers and reclosers which has been saved in a database throughout the year is queried to determine the peak hour electric demand for each of the study areas.

b) This portion of the distribution system is modeled using the Siemens PSS/E planning software product. Updates to the computer model to capture any additions or changes are completed, including, for example, the addition of new substations or distribution lines as well as changes in conductor size or circuit configurations. To ensure that the load is distributed correctly in the model, "Bus Load Data Sheets" are used to capture the correct load level identified with each bus of the model. These data are of actual interval demands for large customers, lower voltage substation loadings, step transformer loadings, recloser loadings, and connected kVA of transformation. The bus load data sheets are updated as needed to accurately represent the circuits. Once these updates are complete, the model is scaled to match the planning area peak demand. This process produces a "Snapshot" of the area peaks, providing a one line diagram with individual transformer and line loading data.

c) The remainder of the distribution system, 4 & 12 kV as well as radial 34.5 kV, is typically modeled and analyzed by the Field Engineering department. Peak demands on substation equipment and distribution lines are collected from substation and recloser loading data maintained in the Cascade maintenance database, step transformer loading, and temporary metering devices used to determine loading and voltage where more sophisticated equipment is not present. This segment of the distribution system is typically modeled in the Aspen Distriview analysis tool. This tool allows for single phase modeling which is necessary to accurately model this level of the electric system. The GIS system recently put in service at Eversource is used to populate the physical characteristics of the conductors and transformers into the model.

d) 4 and 12 kV substation loadings which exceed 85% of the equipment ratings are identified. Solutions to 4 & 12 kV substation equipment overloads typically take up to 3 years to implement, and, therefore, must be identified at least three years in advance.

e) Heavily loaded step transformers, regulators, and conductors, as well as voltage violations and protection sensitivity issues are also identified. Typically solutions to these issues require one to two years to design and construct and therefore are identified when the need to address is imminent.

f) The performance of circuits is continually being analyzed. Each year, lists of the top 50 worst performing circuits is generated based upon a number of criteria including COSAIDI, CAIDI, SAIFI, and Tree COSAIDI to name a few. Customers experiencing multiple interruptions (CEMI) and customers experiencing outages lasting longer than 6 hours (CELID6) are examples of reliability measures analyzed on a monthly basis. These reports are used by the Field Engineering organization to develop project recommendations to improve reliability.

<u>2) Peak Load Forecast</u>

g) Once the System Planning department has determined the previous year's planning area peak loads, a ten year peak demand forecast is prepared. Each planning area is analyzed separately to determine a specific growth rate for each area. The forecast relies upon historical data, weather information, large customer activity, commercial activity, as well as input from the local Field Engineering and Strategic Accounts department. The methodology is defined in greater detail within this submittal. Unitil provides a ten year peak load forecast for their Capital and Seacoast regions, which are supplied by Eversource distribution facilities.

<u>3) Solutions (Least Cost Objectives)</u>

h) The ten year forecast is used to scale the area peak loads for the 10 Year Loadflow Study. The Loadflow study identifies loading and voltage violations in the year that they occur. Some line overloads and most voltage violations can be addressed with relatively inexpensive solutions. Substation overloads are typically costly to address and simply adding additional transformation at the location may not be possible or may not address reliability and aging infrastructure concerns. In these cases a comprehensive study is performed and the results of the study are incorporated into the 10 Year Loadflow Study.

i) A comprehensive area study is performed to ensure that the best, most cost effective solution is chosen that considers net present value, peak demand effectiveness, reliability, power quality, environmental impact, system losses, operating costs, and contingency effectiveness. Alternatives could include elements of transmission, substation, distribution line, conservation & load management and/or distributed generation.

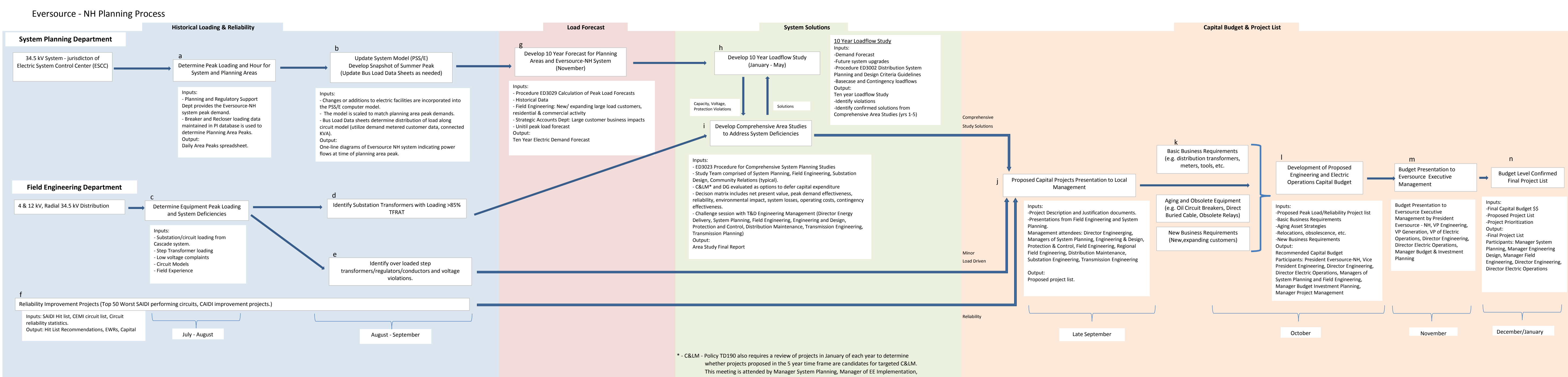
<u>4) Capital Project List Selection</u>

j) All of the proposed projects to address load growth and reliability are presented to local management for review and comment. Once management is convinced of the appropriate solution and scope, the projects are included for consideration in the final budget.

k,l) The list of proposed general load growth and reliability projects are combined with basic business requirements, proposed aging and obsolete equipment projects, and new business requirements to produce a complete list of projects proposed for the capital budget. These projects are ranked by priority considering factors such as equipment loading risk, equipment failure risk, reliability benefit, regulatory requirement, safety, and environmental. Eversource management prepares a capital budget proposal from this list of projects that meets the energy needs of our customers at the lowest reasonable cost.

m) The Eversource capital budget proposal is typically presented to Eversource Energy (Eversource's parent company) executive management in November of each year.

n) Once each operating company has presented its proposed capital budget, the official budget level is confirmed by year end. A final list of capital projects that best meets the needs of our customers at the lowest reasonable cost is selected using updated information from projects underway, the approved budget level, and the proposed project list.


Eversource - NH Planning Process
Historical Loading & Reliability
Load Forecast
System Solutions
Capital Budget & Project List
System Planning Department
34.5 kV System - jurisdicton of Electric System Control Center (ESCC)
a
Determine Peak Loading and Hour for System and Planning Areas
Inputs:
- Planning and Regulatory Support Dept provides the Eversource-NH system peak demand.
- Breaker and Recloser loading data maintained in PI database is used to determine Planning Area Peaks.
Output:
Daily Area Peaks spreadsheet.
b
Update System Model (PSS/E)
Develop Snapshot of Summer Peak
(Update Bus Load Data Sheets as needed)
Inputs:
- Changes or additions to electric facilities are incorporated into the PSS/E computer model.
- The model is scaled to match planning area peak demands.
- Bus Load Data sheets determine distribution of load along circuit model (utilize demand metered customer data, connected KVA).
Output:
One-line diagrams of Eversource NH system indicating power flows at time of planning area peak.
Field Engineering Department
4 & 12 kV, Radial 34.5 kV Distribution
c
Determine Equipment Peak Loading and System Deficiencies
Inputs:
- Substation/circuit loading from Cascade system.
- Step Transformer loading
- Low voltage complaints
- Circuit Models
- Field Experience
d
Identify Substation Transformers with Loading >85% TFRAT
e
Identify over loaded step transformers/regulators/conductors and voltage violations.
f
Reliability Improvement Projects (Top 50 Worst SAIDI performing circuits, CAIDI improvement projects.)
Inputs: SAIDI Hit list, CEMI circuit list, Circuit reliability statistics.
Output: Hit List Recommendations, EWRs, Capital
July - August
August - September
g
Develop 10 Year Forecast for Planning Areas and Eversource-NH System (November)
Inputs:
- Procedure ED3029 Calculation of Peak Load Forecasts
- Historical Data
- Field Engineering: New/ expanding large load customers, residential & commercial activity
- Strategic Accounts Dept: Large customer business impacts
- Unitil peak load forecast
Output:
Ten Year Electric Demand Forecast
h
Develop 10 Year Loadflow Study (January - May)
10 Year Loadflow Study
Inputs:
-Demand Forecast
-Future system upgrades
-Procedure ED3002 Distribution System Planning and Design Criteria Guidelines
-Basecase and Contingency loadflows
Output:
Ten year Loadflow Study
-Identify violations
-Identify confirmed solutions from Comprehensive Area Studies (yrs 1-5)
Capacity, Voltage, Protection Violations
Solutions
i
Develop Comprehensive Area Studies to Address System Deficiencies
Inputs:
- ED3023 Procedure for Comprehensive System Planning Studies
- Study Team comprised of System Planning, Field Engineering, Substation Design, Community Relations (typical).
- C&LM* and DG evaluated as options to defer capital expenditure
- Decison matrix includes net present value, peak demand effectiveness, reliability, environmental impact, system losses, operating costs, contingency effectiveness.
- Challenge session with T&D Engineering Management (Director Energy Delivery, System Planning, Field Engineering, Engineering and Design, Protection and Control, Distribution Maintenance, Transmission Engineering, Transmission Planning)
Output:
Area Study Final Report
* - C&LM - Policy TD190 also requires a review of projects in January of each year to determine whether projects proposed in the 5 year time frame are candidates for targeted C&LM. This meeting is attended by Manager System Planning, Manager of EE Implementation, and Customer Solutions Program Manager.
Comprehensive Study Solutions
Minor Load Driven
Reliability
j
Proposed Capital Projects Presentation to Local Management
Inputs:
-Project Description and Justification documents.
-Presentations from Field Engineering and System Planning.
Management attendees: Director Engineering, Managers of System Planning, Engineering & Design, Protection & Control, Field Engineering, Regional Field Engineering, Distribution Maintenance, Substation Engineering, Transmission Engineering
Output:
Proposed project list.
Late September
k
Basic Business Requirements (e.g. distribution transformers, meters, tools, etc.
Aging and Obsolete Equipment (e.g. Oil Circuit Breakers, Direct Buried Cable, Obsolete Relays)
New Business Requirements (New,expanding customers)
l
Development of Proposed Engineering and Electric Operations Capital Budget
Inputs:
-Proposed Peak Load/Reliability Project list
-Basic Business Requirements
-Aging Asset Strategies
-Relocations, obsolescence, etc.
-New Business Requirements
Output:
Recommended Capital Budget
Participants: President Eversource-NH, Vice President Engineering, Director Engineering, Director Electric Operations, Managers of System Planning and Field Engineering, Manager Budget Investment Planning, Manager Project Management
October
m
Budget Presentation to Eversource Executive Management
Budget Presentation to Eversource Executive Management by President Eversource - NH, VP Engineering, VP Generation, VP of Electric Operations, Director Engineering, Director Electric Operations, Manager Budget & Investment Planning
November
n
Budget Level Confirmed Final Project List
Inputs:
-Final Capital Budget $$
-Proposed Project List
-Project Prioritization
Output:
-Final Project List
Participants: Manager System Planning, Manager Engineering Design, Manager Field Engineering, Director Engineering, Director Electric Operations
December/January

I. PURPOSE

To establish a procedure for calculating the seasonal **Peak Load Forecast** for each of the **loadflow** areas and the PSNH system.

II. AREAS/PERSONS AFFECTED

This procedure applies to or affects:

- PSNH System Planning and Strategy

III. POLICY

It is the policy of PSNH to develop a peak load forecast each year after the summer and winter annual **Peak Load** is achieved. It is intended that this procedure be followed to provide a consistent practice of developing a **Peak Load Forecast** using historical data, known **block load** changes and engineering judgment.

IV. DEFINITIONS

A. **Adjusted Growth Rate (AGR) –** The Compound Growth Rate (CGR) adjusted with input from Field Engineering.

B. **Area Peak Load Tables -** Excel spreadsheets containing historical area **Peak Loads** and Summer and Winter **Peak Load Forecasts** for the next ten years.

C. **Block Loads** – Load changes which may add to or subtract from the forecasted load level for the study area. Additive **Block Loads** are known large industrial customers, blocks of commercial growth, and support of **Rate B customers**. Subtractive **Block Loads** include industrial customer closings.

D. **Compound Growth Rate (CGR)** – The calculation of the peak load growth rate, on average, over a 10 year period based on historical peaks.

E. **Degree Days** - A degree day compares the outdoor mean daily temperature to a standard of 65 degrees Fahrenheit (F).

F. **ESCC** – Electric System Control Center.

G. **Heat wave** – Multiple contiguous days during the summer with cooling **Degree Days** of 17 or higher.

H. **Load Forecast Folder** – K drive folder set up for each study done. This is located at "K:\Deptdata\Energy Delivery\System Plan&Strategy\Load Forecasts" and designated with the year of the forecast calculation.

I. **Loadflow** – The PSS/E computer model of the PSNH electric distribution system.

J. **Loadflow Area** – The 12 different geographical areas modeled in the **Loadflow**.

K. **Peak Load Forecast** – The highest hourly summer and winter load level that is projected to occur in future years.

L. **Peak Load** – The annual highest historical hourly load level achieved during the previous years for summer and winter.

M. **Projected Growth Rate (PGR)** – The annual growth rate that is projected to occur in the future years.

N. **PSNH System** – PSNH defined zones in the **Loadflow**. The **Loadflow** defines the 34.5kV and below system as zones 2 – 8 and 10 - 12. (Zones 9 & 13 are Unitil.)

O. **PI System** – Database of historical operating data which connects the user to the **ESCC** historical load database using Microsoft Excel. This is used for gathering data on distribution loads including 34.5 kV transformers and lines.

P. **Rate B Customer** – A customer with generation that offsets its own load but requires PSNH to have the capability of serving its entire load when generation is out of service.

V. SAFETY MANUAL

No	Should a copy of this procedure be inserted into the functional area's safety and health handbook?

VI. OVERVIEW

The intent of this procedure is to define the steps required to develop 10 year summer and winter **Peak Load Forecasts.**

This process is used to calculate a peak load forecast for each of PSNH's geographical **Loadflow Areas** and the **PSNH System**. Unitil provides forecast information for its **Loadflow Areas** and is included in the **Peak Load Forecast**.

VII. PERIODIC REVIEW OF GUIDELINE

The Procedure Owner is responsible for maintaining this guideline and keeping current with good engineering design practices. The Procedure Owner for this Energy Delivery Procedure is the Manager of System Planning and Strategy.

Annually, the Procedure Owner shall review the design guideline for conformance to standard engineering practices and industry criteria to determine if the guideline shall be revised, rewritten, or cancelled.

As required, the Procedure Owner shall recommend changes to the Director of Energy Delivery. If approved by the Director, the Procedure Owner shall change the Procedure in accordance with AP-2001 Writing and Publishing Procedures.

VIII. PROCEDURE

A. Identify Current Year Area Peaks

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Copy last year's folder and update the name to include the new year. This folder is located in "K:\Deptdata\Energy Delivery\System Plan&Strategy\Load Forecast\". The naming format is 'YYYY Summer Forecast', for the summer forecast and 'YYYY-YY Winter Forecast', for the winter. (The new folder is the folder you will be working with for the rest of this procedure).
System Planning & Strategy	2.	Open "Current Summer System Loading.xls" Shown in (APPENDIX A) for summer loading and "Current Winter System Loading.xls" for winter loading.
System Planning & Strategy	3.	On this loading spreadsheet, update the start and end dates for each month. Only the year should be changed. Note: after the date has been updated 'F9' must be pressed to update the data. (This will download monthly peak load data from PI, for each area)
System Planning & Strategy	4.	Verify the daily data to make sure it corresponds with the rest of the days in the month. (Invalid data can be received; change the invalid data font to red and ignore these values). If you question the value verify it with the ESCC and/or the Circuit Owner.
System Planning & Strategy	5.	Identify the peak load for each area by updating the formula in the 'Monthly Maximum' row to exclude invalid data (Appendix A).
System Planning & Strategy	6.	Verify the configuration of each area at the time of the area's peak with the ESCC and/or the Circuit Owner.
System Planning & Strategy	7.	Adjust the area peak load if necessary by adding or subtracting load that was switched to another area at the time of peak.

System Planning & Strategy	8.	Identify the season's maximum for each area. Winter months are: December, January, February, and March. Summer months are June, July, and August.
System Planning & Strategy	9.	If the **AREA** peak for the current year is a new historical system peak, then this is used to develop the new **Loadflow Area** and **PSNH System** forecasts. Skip Step 10 and continue to Section B.
System Planning & Strategy	10.	If the current year's peak is not a new historical peak, then the Peak Load Forecast shall be based upon the highest recorded peak within the previous five years where consecutive days of 17 cooling degree days occurred.

EXCEPTIONS

a. If the 5 year historical peak is prior to the last year with consecutive days of 17 cooling degree days, use the last year with consecutive days of 17 cooling degree days as the 5 year historical peak year.
b. If the 5 year historical peak is after the last year with consecutive days of 17 cooling degree days, use the data from the year that yields the larger forecasted value.

B. Update PSNH System Current Year Loads

RESPONSIBILITY		ACTION
Marketing Support	1.	The Load Research Group in the Marketing Support Department calculates the load in MWH at the time, hour, and day of the current year's peak at "PSNH Delivered Peak Load" report.
System Planning & Strategy	2.	Open the previous years forecast "YYYY-YY Winter Forecast.xls" for winter and "YYYY Summer Forecast.xls" for summer. Save the file using the current year in the 'Y' locations. Notice there are multiple tabs. Press the tab to bring up the sheet titled "Peak_Loads". (Appendix B).

System Planning & Strategy	3.	Insert a line underneath the last year's data and follow the format of the previous year, inputting each area's new peak, calculated in Sections A. (Appendix C).
System Planning & Strategy	4.	From the Marketing Support Department's "PSNH Delivered Peak Load Report", insert the value "PSNH Peak Load Including NHEC, Ashland, New Hampton and Wolfeboro Wholesale Loads Excludes AES OFFLINE SS Excludes CVEC Load" in the **Area Peak Load Table** in the current year PSNH **Peak Load** cell.
System Planning & Strategy	5.	If the year had multiple consecutive 17 cooling **Degree Days**, shade the rows light gray as done in previous years. Cooling **Degree Day** information is located at 'K:\Deptdata\Energy Delivery\System Plan&Strategy\Load ForecastsCDD_ALLYEARS.xls'

C. Incorporate Unitil System Forecast

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Include in **Area Peak Load Tables** the peak load forecast for UES/Capital and UES/Seacoast areas provided by UES. **UES/Capital** – The Unitil Electric region that serves the Concord area. **UES/Seacoast** – The Unitil Electric region on the Seacoast including Hampton, Exeter, Seabrook, Kingston, etc.

D. Update PSNH Area Peak Load Forecasts

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Calculate the percent difference (% Difference). This can be done by copying and pasting the formula in the above cell. (Appendix D). The formula is: $\left(\frac{CurrentYear}{PreviousYear}\right)-1$

System Planning & Strategy	2.	Calculate the Compound Growth Rate (CGR). (Appendix E). The formula is: $$CGR = \left[\left(\frac{5YearHistorPk}{10YrOldPk} \right)^{\frac{1}{x}} - 1 \right]$$ X=PkYr-10YrPkYr Note: If the 10 year old peak is a low point compared to the surrounding peaks, adjust the 10 year 'look back time' to 11 years based on the higher peak and then update formula. (Appendix F).
System Planning & Engineering	3.	Update the Adjusted Growth Rate (AGR). This is done based on the Compound Growth Rate (CGR) and with input from circuit owners and Division Field Engineering Managers.
System Planning & Strategy	4.	Update the Projected Growth Rate (PGR). This is done based on rounding the CGR up to the next 0.25%. (Note: Minimum PGR is 0.5%.)
System Planning & Strategy	5.	Update the next year's peak. (Appendix G). The following equation: $NxtYrPk = (5YearHistorPk)(1 + AGR)^{NxtYr - 5YearHistorPkYr}$ <u>EXCEPTIONS</u> a. If the 5 year historical peak is prior to the last year with consecutive days of 17 cooling degree days, use the last year with consecutive days of 17 cooling degree days as the 5 year historical peak year. b. If the 5 year historical peak is after the last year with consecutive days of 17 cooling degree days, use the data from the year that yields the larger forecasted value.

System Planning & Strategy	7.	Update the forecast for the next 10 years. Adjust the first forecasted year in Column A to reflect the next year (Appendix C), all other years will automatically update. Calculate future peaks for years 2 – 5 (Appendix G) using the equation below:

$$FuturePks(2-5) = (\Pr eviousYrPk)(1 + AGR)$$

Calculate the future peaks for years 6-10 using the following equation:

$$FuturePks(6-10) = (\Pr eviousYrPk)(1 + PGR)$$

System Planning & Strategy	8.	Repeat sections D.1-D.7 for all Loadflow Areas & PSNH System.

E. Area Peak Load Graph Adjustment

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Update **AREA** by clicking on its tab. Notice each **AREA** has its own tab at the bottom of the **Area Peak Load Tables**.
System Planning & Engineering	2.	Enter the areas seasonal peak in its sheet. Add any new rows and copy the formulas from any existing rows into the new rows to maintain a 10 year projection. (Appendix H).
System Planning & Strategy	3.	Adjust the Low and High Annual Growth rates and analyze the sensitivity of the previously determined Projected Annual Growth Rate.
System Planning & Strategy	4.	Change the "Adjustable" percentage to ensure that the **PGR** accurately follows the envelope. If a better match is found update the **PGR**.

F. Finalize Peak Load Forecast

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Add and adjust spreadsheet notes to include pertinent information for the **Peak Load Forecast.**
System Planning & Strategy	2.	Save **Peak Load Forecast** in the **Load Forecast Folder**. Change spreadsheet properties to be a read-only file.
System Planning & Strategy	3.	Revise throughout the year as required, saving each update as a Revision.

IX ED-3029 REVISION HISTORY

Revision Number	Date	Reason
Rev 0	05/04/2007	Original issue
Rev 1	10/24/2007	Minor housekeeping Changes
Rev 2	05/06/2015	Complete Rework

X. APPENDICES

APPENDIX A
ACQUIRE PEAK LOAD INFORMATION

APPENDIX B
FORECAST SPREADSHEET OVERVIEW

APPENDIX C
RECORD PEAK LOAD INFORMATION

APPENDIX D
CALCULATE PERCENT DIFFERENCE

APPENDIX E
CALCULATE NEW COMPOUND GROWTH RATE (10 YEAR)

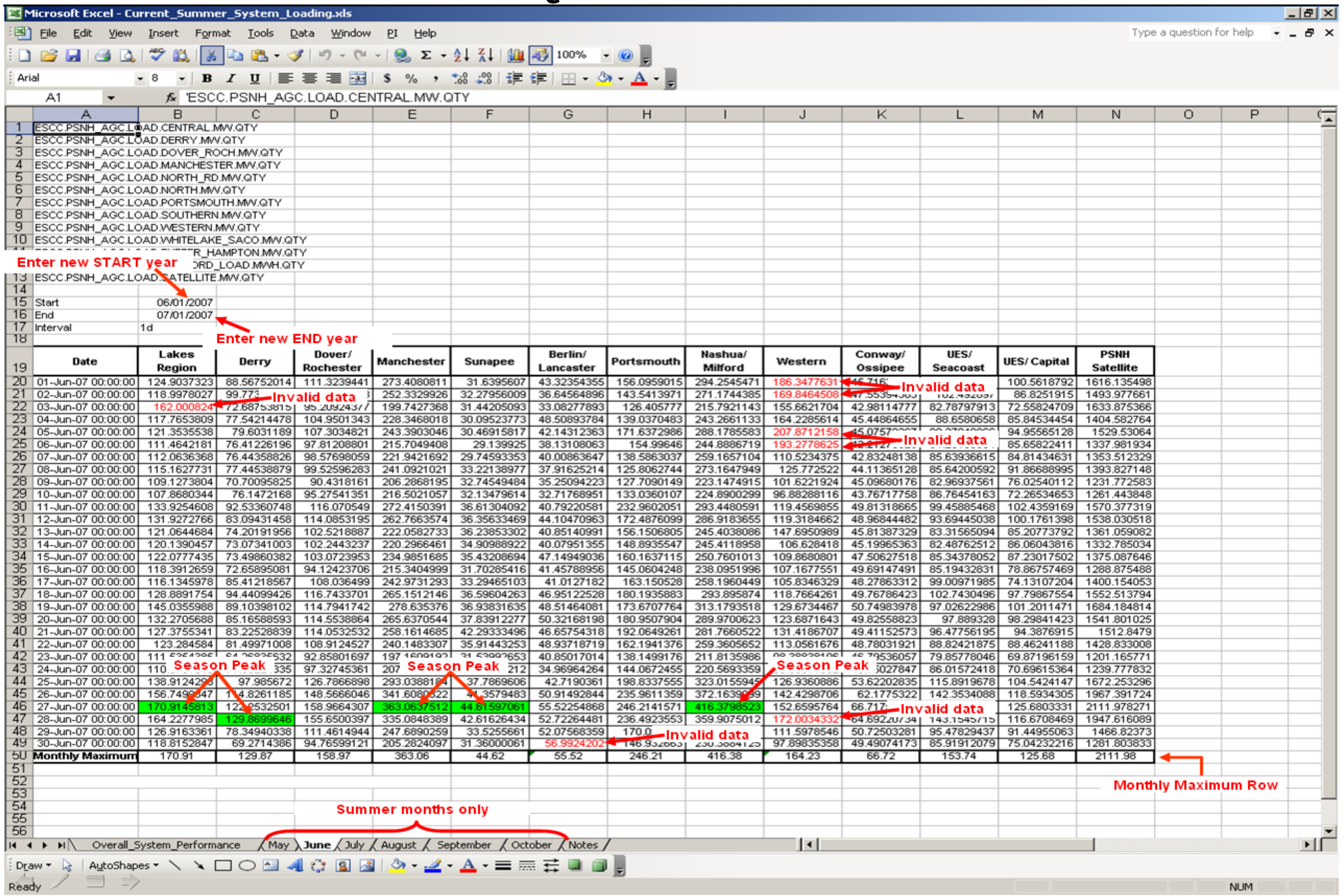
APPENDIX F
CALCULATE NEW COMPOUND GROWTH RATE (OTHER THAN 10 YEARS)

APPENDIX G
CALCULATE PROJECTED GROWTH

APPENDIX H

UPDATE AREA CHARTS AND GRAPHS

APPENDIX A – ACQUIRE PEAK LOAD INFORMATION



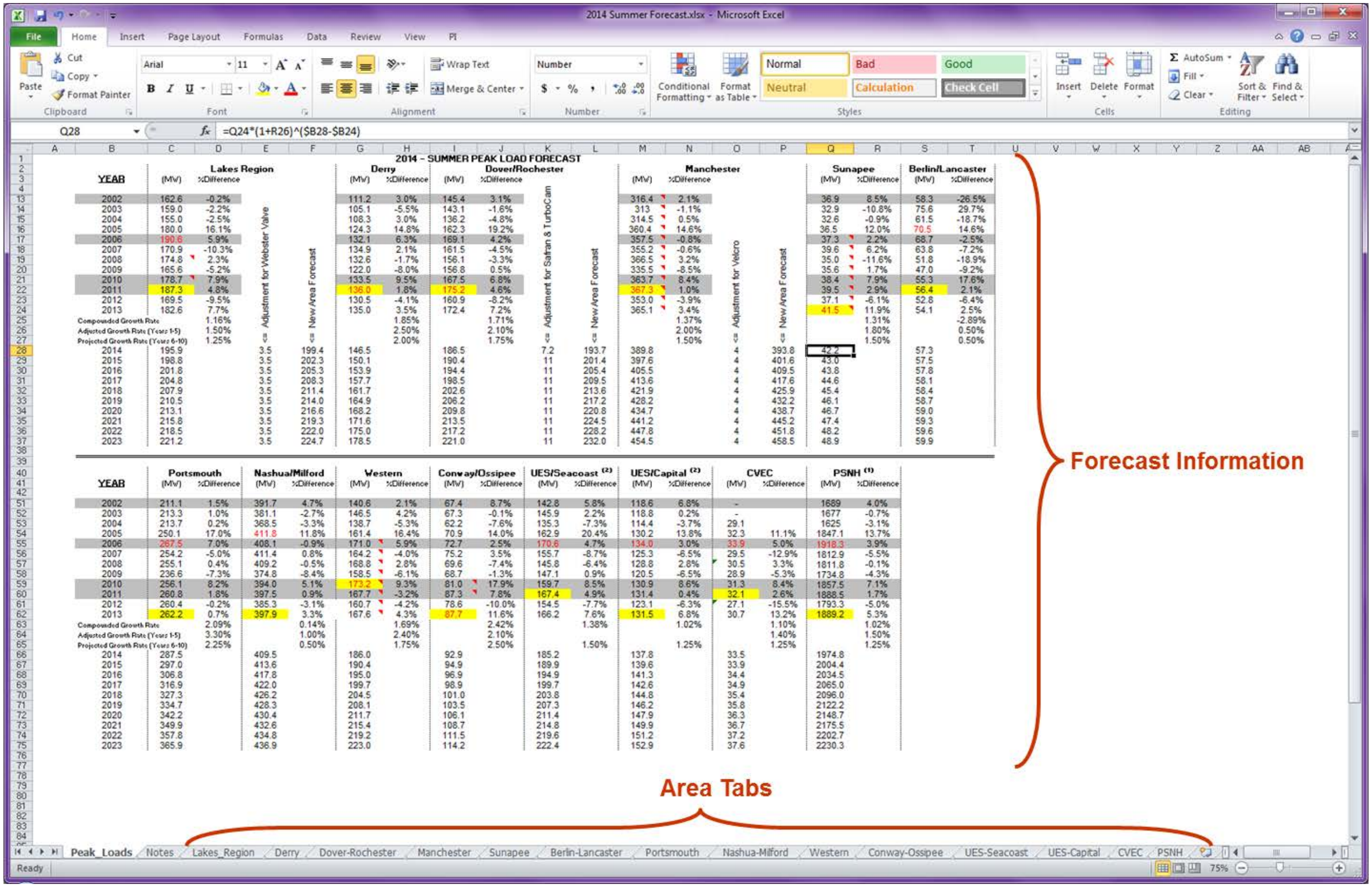
A1 'ESCC.PSNH_AGC.LOAD.CENTRAL.MW.QTY

	A	B
1	ESCC.PSNH_AGC.LOAD.CENTRAL.MW.QTY	
2	ESCC.PSNH_AGC.LOAD.DERRY.MW.QTY	
3	ESCC.PSNH_AGC.LOAD.DOVER_ROCH.MW.QTY	
4	ESCC.PSNH_AGC.LOAD.MANCHESTER.MW.QTY	
5	ESCC.PSNH_AGC.LOAD.NORTH_RD.MW.QTY	
6	ESCC.PSNH_AGC.LOAD.NORTH.MW.QTY	
7	ESCC.PSNH_AGC.LOAD.PORTSMOUTH.MW.QTY	
8	ESCC.PSNH_AGC.LOAD.SOUTHERN.MW.QTY	
9	ESCC.PSNH_AGC.LOAD.WESTERN.MW.QTY	
10	ESCC.PSNH_AGC.LOAD.WHITELAKE_SACO.MW.QTY	
11	...R_HAMPTON.MW.QTY	
12	...ORD_LOAD.MWH.QTY	
13	ESCC.PSNH_AGC.LOAD.SATELLITE.MW.QTY	
14		
15	Start	06/01/2007
16	End	07/01/2007
17	Interval	1d
18		

19	Date	Lakes Region	Derry	Dover/ Rochester	Manchester	Sunapee	Berlin/ Lancaster
20	01-Jun-07 00:00:00	124.9037323	88.56752014	111.3239441	273.4080811	31.6395607	43.32354355
21	02-Jun-07 00:00:00	118.9978027	99.773[illegible]	[illegible]	252.3329926	32.27956009	36.64564896
22	03-Jun-07 00:00:00	162.000824	72.68753815	95.20924377	199.7427368	31.44205093	33.08277893
23	04-Jun-07 00:00:00	117.7653809	77.54214478	104.9501343	228.3468018	30.09523773	48.50893784
24	05-Jun-07 00:00:00	121.3535538	79.6031189	107.3034821	243.3903046	30.46915817	42.14312363
25	06-Jun-07 00:00:00	111.4642181	76.41226196	97.81208801	215.7049408	29.139925	38.13108063
26	07-Jun-07 00:00:00	112.0636368	76.44358826	98.57698059	221.9421692	29.74593353	40.00863647
27	08-Jun-07 00:00:00	115.1627731	77.44538879	99.52596283	241.0921021	33.22138977	37.91625214
28	09-Jun-07 00:00:00	109.1273804	70.70095825	90.4318161	206.2868195	32.74549484	35.25094223
29	10-Jun-07 00:00:00	107.8680344	76.1472168	95.27541351	216.5021057	32.13479614	32.71768951
30	11-Jun-07 00:00:00	133.9254608	92.53360748	116.070549	272.4150391	36.61304092	40.79220581
31	12-Jun-07 00:00:00	131.9272766	83.09431458	114.0853195	262.7663574	36.35633469	44.10470963
32	13-Jun-07 00:00:00	121.0644684	74.20191956	102.5218887	222.0582733	36.23853302	40.85140991
33	14-Jun-07 00:00:00	120.1390457	73.07341003	102.2443237	220.2966461	34.90988922	40.07951355
34	15-Jun-07 00:00:00	122.0777435	73.49860382	103.0723953	234.9851685	35.43208694	47.14949036
35	16-Jun-07 00:00:00	118.3912659	72.65895081	94.12423706	215.3404999	31.70285416	41.45788956
36	17-Jun-07 00:00:00	116.1345978	85.41218567	108.036499	242.9731293	33.29465103	41.0127182
37	18-Jun-07 00:00:00	128.8891754	94.44099426	116.7433701	265.1512146	36.59604263	46.95122528
38	19-Jun-07 00:00:00	145.0355988	89.10398102	114.7941742	278.635376	36.93831635	48.51464081
39	20-Jun-07 00:00:00	132.2705688	85.16588593	114.5538864	265.6370544	37.83912277	50.32168198
40	21-Jun-07 00:00:00	127.3755341	83.22528839	114.0532532	258.1614685	42.29333496	46.65754318
41	22-Jun-07 00:00:00	123.284584	81.49971008	108.9124527	240.1483307	35.91443253	48.93718719
42	23-Jun-07 00:00:00	111.[illegible]	[illegible]532	92.85801697	197.[illegible]	31.[illegible]653	40.85017014
43	24-Jun-07 00:00:00	110.[illegible]	[illegible]335	97.32745361	207.[illegible]	[illegible]212	34.96964264
44	25-Jun-07 00:00:00	138.9124[illegible]	97.985672	126.7866898	293.0388[illegible]	37.7869606	42.7190361
45	26-Jun-07 00:00:00	156.749[illegible]	1[illegible]4.8261185	148.5666046	341.608[illegible]	4[illegible].3579483	50.91492844
46	27-Jun-07 00:00:00	170.9145813	12[illegible].2532501	158.9664307	363.0637512	44.61597061	55.52254868
47	28-Jun-07 00:00:00	164.2277985	129.8699646	155.6500397	335.0848389	42.61626434	52.72264481
48	29-Jun-07 00:00:00	126.9163361	78.34940338	111.4614944	247.6890259	33.5255661	52.07568359
49	30-Jun-07 00:00:00	118.8152847	69.2714386	94.76599121	205.2824097	31.36000061	56.9924202
50	Monthly Maximum	170.91	129.87	158.97	363.06	44.62	55.52

19	Portsmouth	Nashua/ Milford	Western	Conway/ Ossipee	UES/ Seacoast	UES/ Capital	PSNH Satellite
20	156.0959015	294.2545471	186.3477631	45.716[illegible]	[illegible]	100.5618792	1616.135498
21	143.5413971	271.1744385	169.8464508	47.5535[illegible]	102.492[illegible]	86.8251915	1493.977661
22	126.405777	215.7921143	155.6621704	42.98114777	82.78797913	72.55824709	1633.875366
23	139.0370483	243.2661133	164.2285614	45.44864655	88.6580658	85.84534454	1404.582764
24	171.6372986	288.1785583	207.8712158	45.0757[illegible]	[illegible]	94.95565128	1529.53064
25	154.99646	244.8886719	193.2778625	[illegible]	[illegible]	85.65822411	1337.981934
26	138.5863037	259.1657104	110.5234375	42.83248138	85.63936615	84.81434631	1353.512329
27	125.8062744	273.1647949	125.772522	44.11365128	85.64200592	91.86688995	1393.827148
28	127.7090149	223.1474915	101.6221924	45.09680176	82.96937561	76.02540112	1231.772583
29	133.0360107	224.8900299	96.88288116	43.76717758	86.76454163	72.26534653	1261.443848
30	232.9602051	293.4480591	119.4569855	49.81318665	99.45885468	102.4359169	1570.377319
31	172.4876099	286.9183655	119.3184662	48.96844482	93.69445038	100.1761398	1538.030518
32	156.1506805	245.4038086	147.6950989	45.81387329	83.31565094	85.20773792	1361.059082
33	148.8935547	245.4118958	106.628418	45.19965363	82.48762512	86.06043816	1332.785034
34	160.1637115	250.7601013	109.8680801	47.50627518	85.34378052	87.23017502	1375.087646
35	145.0604248	238.0951996	107.1677551	49.69147491	85.19432831	78.86757469	1288.875488
36	163.150528	258.1960449	105.8346329	48.27863312	99.00971985	74.13107204	1400.154053
37	180.1935883	293.895874	118.7664261	49.76786423	102.7430496	97.79867554	1552.513794
38	173.6707764	313.1793518	129.6734467	50.74983978	97.02622986	101.2011471	1684.184814
39	180.9507904	289.9700623	123.6871643	49.82558823	97.889328	98.29841423	1541.801025
40	192.0649261	281.7660522	131.4186707	49.41152573	96.47756195	94.3876915	1512.8479
41	162.1941376	259.3605652	113.0561676	48.78031921	88.82421875	88.46241188	1428.833008
42	138.1499176	211.8135986	[illegible]	4[illegible].79536057	79.85778046	69.87196159	1201.165771
43	144.0672455	220.5693359	[illegible]	[illegible]5027847	86.01572418	70.69615364	1239.777832
44	198.8337555	323.0155945	126.9360886	53.62202835	115.8919678	104.5424147	1672.253296
45	235.9611359	372.1639[illegible]	142.4298706	62.1775322	142.3534088	118.5934305	1967.391724
46	246.2141571	416.3798523	152.6595764	66.717[illegible]	[illegible]	125.6803331	2111.978271
47	236.4923553	359.9075012	172.0034332	64.69220734	143.1545715	116.6708469	1947.616089
48	170.0[illegible]	[illegible]	111.5978546	50.72503281	95.47829437	91.44955063	1466.82373
49	146.9[illegible]	230.[illegible]	97.89835358	49.49074173	85.91912079	75.04232216	1281.803833
50	246.21	416.38	164.23	66.72	153.74	125.68	2111.98

APPENDIX B – FORECAST SPREADSHEET OVERVIEW



2014 – SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	Lakes Region %Difference	<= Adjustment for Webster Valve	<= New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	<= Adjustment for Safran & TurboCam	<= New Area Forecast	Manchester (MW)	Manchester %Difference	<= Adjustment for Velcro	<= New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

YEAR	Portsmouth (MW)	Portsmouth %Difference	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	Conway/Ossipee (MW)	Conway/Ossipee %Difference	UES/Seacoast (2) (MW)	UES/Seacoast (2) %Difference	UES/Capital (2) (MW)	UES/Capital (2) %Difference	CVEC (MW)	CVEC %Difference	PSNH (1) (MW)	PSNH (1) %Difference
2002	211.1	1.5%	391.7	4.7%	140.6	2.1%	67.4	8.7%	142.8	5.8%	118.6	6.8%	-		1689	4.0%
2003	213.3	1.0%	381.1	-2.7%	146.5	4.2%	67.3	-0.1%	145.9	2.2%	118.8	0.2%	-		1677	-0.7%
2004	213.7	0.2%	368.5	-3.3%	138.7	-5.3%	62.2	-7.6%	135.3	-7.3%	114.4	-3.7%	29.1		1625	-3.1%
2005	250.1	17.0%	411.8	11.8%	161.4	16.4%	70.9	14.0%	162.9	20.4%	130.2	13.8%	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	408.1	-0.9%	171.0	5.9%	72.7	2.5%	170.6	4.7%	134.0	3.0%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	411.4	0.8%	164.2	-4.0%	75.2	3.5%	155.7	-8.7%	125.3	-6.5%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	409.2	-0.5%	168.8	2.8%	69.6	-7.4%	145.8	-6.4%	128.8	2.8%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	374.8	-8.4%	158.5	-6.1%	68.7	-1.3%	147.1	0.9%	120.5	-6.5%	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	394.0	5.1%	173.2	9.3%	81.0	17.9%	159.7	8.5%	130.9	8.6%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	397.5	0.9%	167.7	-3.2%	87.3	7.8%	167.4	4.9%	131.4	0.4%	32.1	2.6%	1888.5	1.7%
2012	260.4	-0.2%	385.3	-3.1%	160.7	-4.2%	78.6	-10.0%	154.5	-7.7%	123.1	-6.3%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	397.9	3.3%	167.6	4.3%	87.7	11.6%	166.2	7.6%	131.5	6.8%	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		0.14%		1.69%		2.42%		1.38%		1.02%		1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%		1.00%		2.40%		2.10%						1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%		0.50%		1.75%		2.50%		1.50%		1.25%		1.25%		1.25%
2014	287.5		409.5		186.0		92.9		185.2		137.8		33.5		1974.8	
2015	297.0		413.6		190.4		94.9		189.9		139.6		33.9		2004.4	
2016	306.8		417.8		195.0		96.9		194.9		141.3		34.4		2034.5	
2017	316.9		422.0		199.7		98.9		199.7		142.6		34.9		2065.0	
2018	327.3		426.2		204.5		101.0		203.8		144.8		35.4		2096.0	
2019	334.7		428.3		208.1		103.5		207.3		146.2		35.8		2122.2	
2020	342.2		430.4		211.7		106.1		211.4		147.9		36.3		2148.7	
2021	349.9		432.6		215.4		108.7		214.8		149.9		36.7		2175.5	
2022	357.8		434.8		219.2		111.5		219.6		151.2		37.2		2202.7	
2023	365.9		436.9		223.0		114.2		222.4		152.9		37.6		2230.3	

APPENDIX C – RECORD PEAK LOAD INFORMATION

2008 - SUMMER PEAK LOAD FORECAST (rev.1 - 5/15/08)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
4		Lakes Region		Derry		Dover/Rochester		Manchester		Sunapee		Berlin/Lancaster		Portsmouth	
5	YEAR	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference
7	1994	114.8		54.5		116.3		237.7		30.7		69.2		138.5	
8	1995	126.6	10.3%	60.9	11.7%	116.1	-0.2%	244.6	2.9%	33.2	8.1%	78.6	13.6%	149.3	7.8%
9	1996	126.8	0.2%	74.1	21.7%	112.0	-3.5%	223.3	-8.7%	30.5	-8.1%	71.4	-9.2%	157.8	5.7%
10	1997	131.2	3.5%	78.3	5.7%	116.1	3.7%	246.7	10.5%	31.9	4.6%	73.6	3.1%	155.6	-1.4%
11	1998	136.0	3.7%	84.3	7.7%	113.7	-2.1%	262.9	6.6%	31.5	-1.3%	73.9	0.4%	166.5	7.0%
12	1999	143.2	5.3%	90.7	7.6%	118.7	4.4%	288.0	9.5%	26.7	-15.2%	81.4	10.1%	173.1	4.0%
13	2000	132.9	-7.2%	91.0	0.3%	119.5	0.7%	265.0	-8.0%	33.1	24.0%	85.7	5.3%	171.6	-0.9%
14	2001	163.0	22.6%	108.0	18.7%	141.0	18.0%	310.0	17.0%	34.0	2.7%	79.3	-7.5%	208.0	21.2%
15	2002	162.6	-0.2%	111.2	3.0%	145.4	3.1%	323.3	4.3%	36.9	8.5%	58.3	-26.5%	211.1	1.5%
16	2003	159.0	-2.2%	105.1	-5.5%	143.1	-1.6%	318.5	-1.5%	32.9	-10.8%	75.6	29.7%	213.3	1.0%
Added new line		5.0	-2.5%	108.3	3.0%	136.2	-4.8%	319.7	0.4%	32.6	-0.9%	61.5	-18.7%	213.7	0.2%
18	2005	180.0	16.1%	124.3	14.8%	162.3	19.2%	365.9	14.5%	36.5	12.0%	70.5	14.6%	250.1	17.0%
19	2006	190.6	5.9%	132.1	6.3%	169.1	4.2%	363.2	-0.7%	40.3	10.3%	68.7	-2.5%	267.5	7.0%
20	2007	170.9	-10.3%	134.9	2.1%	161.5	-4.5%	363.1	0.0%	42.6	5.8%	63.8	-7.2%	254.2	-5.0%
21	Compounded Growth Rate		4.16%		5.59%		3.48%		4.11%		2.93%		-1.08%		5.42%
22	Projected Growth Rate		4.00%		6.00%		3.00%		4.00%		3.50%		0.50%		5.50%
23	2008	203.0		148.6		170.5		407.3		46.6		83.9		300.0	
24	2009	211.1		157.6		175.6		423.6		48.2		84.3		316.5	
25	2010	Update year		167.0		180.9		440.5		49.9		84.7		333.9	
26	2011	228.4		177.0		186.3		458.1		51.6		85.1		352.3	
27	2012	237.5		187.7		191.9		476.5		53.4		85.6		371.7	
28	2013	247.0		198.9		197.7		495.5		55.3		86.0		392.1	
29	2014	256.9		210.8		203.6		515.3		57.3		86.4		413.7	
30	2015	267.1		223.5		209.7		535.9		59.3		86.8		436.4	
31	2016	277.8		236.9		216.0		557.4		61.3		87.3		460.4	
32	2017	288.9		251.1		222.5		579.7		63.5		87.7		485.7	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
36		Nashua/Milford		Western		Conway/Ossipee		UES/Seacoast		UES/Capital		CVEC		PSNH [4]	
37	YEAR	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference
39	1994	309.3		108.5		49.0		101.7		91.3				1291	
40	1995	307.2	-0.7%	109.0	0.5%	50.8	3.7%	106.2	4.4%	93.8	2.7%			1309	1.4%
41	1996	294.0	-4.3%	106.2	-2.6%	49.8	-2.0%	109.6	3.2%	95.8	2.1%			1266	-3.3%
42	1997	320.0	8.8%	117.7	10.8%	51.0	2.4%	111.6	1.8%	97.2	1.5%			1323	4.5%
43	1998	332.9	4.0%	125.8	6.9%	53.8	5.5%	115.2	3.2%	101.5	4.4%			1406	6.3%
44	1999	352.9	6.0%	128.9	2.5%	58.2	8.2%	118.8	3.1%	102.0	0.5%			1479	5.2%
45	2000	340.0	-3.7%	125.5	-2.7%	53.7	-7.7%	114.7	-3.5%	100.2	-1.8%			1447	-2.2%
46	2001	374.0	10.0%	137.7	9.7%	62.0	15.5%	135.0	17.7%	111.0	10.8%			1624	12.2%
47	2002	391.7	4.7%	140.6	2.1%	67.4	8.7%	142.8	5.8%	118.6	6.8%			1689	4.0%
48	2003	381.1	-2.7%	146.5	4.2%	67.3	-0.1%	145.9	2.2%	118.8	0.2%			1677	-0.7%
Added new line		8.5	-3.3%	138.7	-5.3%	62.2	-7.6%	135.3	-7.3%	114.4	-3.7%	29.1		1625	-3.1%
50	2005	411.8	11.8%	161.4	16.4%	70.9	14.0%	162.9	20.4%	130.2	13.8%	32.3	11.1%	1847.1	13.7%
51	2006	408.1	-0.9%	168.0	4.1%	72.7	2.5%	164.32	0.9%	134.6	3.4%	33.9	5.0%	1918.3	3.9%
52	2007	411.4	0.8%	161.2	-4.1%	75.2	3.5%	155.30	-5.5%	126.1	-6.3%	29.5	-12.9%	1812.9	-5.5%
53	Compounded Growth Rate		2.64%		4.01%		3.96%		4.05%		3.34%		7.98%		3.54%
54	Projected Growth Rate		2.50%		3.70%		3.70%		4.00%		3.50%		3.50%		3.40%
55	2008	423.5		174.8		76.1		184.5		142.7		33.4		2021.7	
56	2009	434.1		181.3		78.9		191.1		146.3		34.5		2090.4	
57	2010	Update year		188.0		81.8		197.7		150.0		35.8		2161.5	
58	2011	456.0		194.9		84.8		204.3		153.6		37.0		2235.0	
59	2012	467.4		202.1		88.0		211.0		157.2		38.3		2310.9	
60	2013	479.1		209.6		91.2		217.7		160.9		39.6		2389.5	
61	2014	491.1		217.4		94.6		224.3		164.5		41.0		2470.8	
62	2015	503.4		225.4		98.1		231.0		168.2		42.5		2554.8	
63	2016	516.0		233.8		101.7		237.6		171.8		43.9		2641.6	
64	2017	528.9		242.4		105.5		244.3		175.5		45.5		2731.4	

APPENDIX D – CALCULATE PERCENT DIFFERENCE

2008 - SUMMER PEAK LOAD FORECAST (rev.1 - 5/15/08)

	YEAR	Lakes Region (MW)	Lakes Region %Difference	Derry (MW)	Derry %Difference	Manchester (MW)	Manchester %Difference	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference	Portsmouth (MW)	Portsmouth %Difference
7	1994	114.8		54.5				30.7		69.2		138.5	
8	1995	126.6	10.3%	60.9	11.7%			33.2	8.1%	78.6	13.6%	149.3	7.8%
9	1996	126.8	0.2%	74.1	21.7%			[illegible]	[illegible]	71.4	-9.2%	157.8	5.7%
10	1997	131.2	3.5%	78.3	5.7%			[illegible]	[illegible]	73.6	3.1%	155.6	-1.4%
11	1998	136.0	3.7%	84.3	7.7%			[illegible]	[illegible]	73.9	0.4%	166.5	7.0%
12	1999	143.2	5.3%	90.7	7.6%			[illegible]	[illegible]	81.4	10.1%	173.1	4.0%
13	2000	132.9	-7.2%	91.0	0.3%			[illegible]	24.0%	85.7	5.3%	171.6	-0.9%
14	2001	163.0	22.6%	108.0	18.7%			[illegible]	2.7%	79.3	-7.5%	208.0	21.2%
15	2002	162.6	-0.2%	111.2	3.0%			[illegible]	8.5%	58.3	-26.5%	211.1	1.5%
16	2003	159.0	-2.2%	105.1	-5.5%			[illegible]	-10.8%	75.6	29.7%	213.3	1.0%
17	2004	155.0	-2.5%	108.3	3.0%			[illegible]	-0.9%	61.5	-18.7%	213.7	0.2%
18	2005	180.0	16.1%	124.3	14.8%			[illegible]	12.0%	70.5	14.6%	250.1	17.0%
19	2006	190.6	5.9%	132.1	6.3%			[illegible]	10.3%	68.7	-2.5%	267.5	7.0%
20	2007	170.9	-10.3%	134.9	2.1%			[illegible]	5.8%	63.8	-7.2%	254.2	-5.0%
21	Compounded Growth Rate		4.16%		5.59%				2.93%		-1.08%		5.42%
22	Projected Growth Rate		4.00%		6.00%				[illegible]		0.50%		5.50%
23	2008	203.0		148.6				[illegible]		83.9		300.0	
24	2009	211.1		157.6				[illegible]		84.3		316.5	
25	2010	219.6		167.0				49.9		84.7		333.9	
26	2011	228.4		177.0				51.6		85.1		352.3	
27	2012	237.5		187.7				53.4		85.6		371.7	
28	2013	247.0		198.9				55.3		86.0		392.1	
29	2014	256.9		210.8				57.3		86.4		413.7	
30	2015	267.1		223.5				59.3		86.8		436.4	
31	2016	277.8		236.9				61.3		87.3		460.4	
32	2017	288.9		251.1				63.5		87.7		485.7	

Derry

(MW)	%Difference
54.5	
60.9	11.7%
74.1	21.7%
78.3	5.7%
84.3	7.7%
90.7	7.6%
91.0	0.3%
108.0	18.7%
111.2	3.0%
105.1	-5.5%
108.3	3.0%
124.3	14.8%
132.1	6.3%
134.9	
	5.5[illegible]
	6.0[illegible]
148.6	
157.6	
167.0	
177.0	
187.7	
198.9	
210.8	
223.5	
236.9	
251.1	

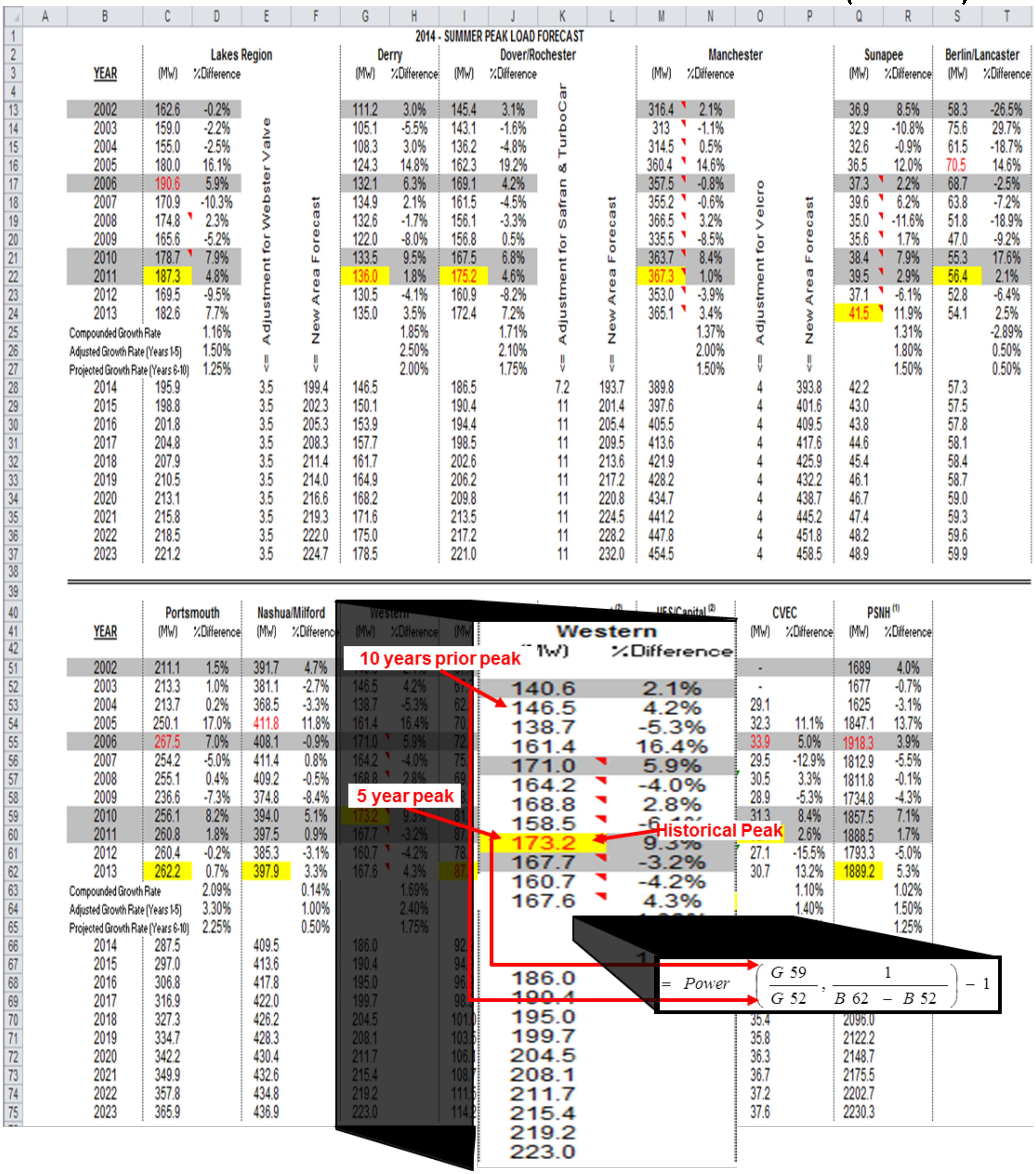
$= D8 / D7 - 1$

$= D9 / D8 - 1$

$= D20 / D19 - 1$

	YEAR	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	Conway/Ossipee (MW)	Conway/Ossipee %Difference	UES/Seacoast (MW)	UES/Seacoast %Difference	UES/Capital (MW)	UES/Capital %Difference	CVEC (MW)	CVEC %Difference	PSNH [1] (MW)	PSNH [1] %Difference
39	1994	309.3		108.5		49.0		101.7		91.3				1291	
40	1995	307.2	-0.7%	109.0	0.5%	50.8	3.7%	106.2	4.4%	93.8	2.7%			1309	1.4%
41	1996	294.0	-4.3%	106.2	-2.6%	49.8	-2.0%	109.6	3.2%	95.8	2.1%			1266	-3.3%
42	1997	320.0	8.8%	117.7	10.8%	51.0	2.4%	111.6	1.8%	97.2	1.5%			1323	4.5%
43	1998	332.9	4.0%	125.8	6.9%	53.8	5.5%	115.2	3.2%	101.5	4.4%			1406	6.3%
44	1999	352.9	6.0%	128.9	2.5%	58.2	8.2%	118.8	3.1%	102.0	0.5%			1479	5.2%
45	2000	340.0	-3.7%	125.5	-2.7%	53.7	-7.7%	114.7	-3.5%	100.2	-1.8%			1447	-2.2%
46	2001	374.0	10.0%	137.7	9.7%	62.0	15.5%	135.0	17.7%	111.0	10.8%			1624	12.2%
47	2002	391.7	4.7%	140.6	2.1%	67.4	8.7%	142.8	5.8%	118.6	6.8%			1689	4.0%
48	2003	381.1	-2.7%	146.5	4.2%	67.3	-0.1%	145.9	2.2%	118.8	0.2%			1677	-0.7%
49	2004	368.5	-3.3%	138.7	-5.3%	62.2	-7.6%	135.3	-7.3%	114.4	-3.7%	29.1		1625	-3.1%
50	2005	411.8	11.8%	161.4	16.4%	70.9	14.0%	162.9	20.4%	130.2	13.8%	32.3	11.1%	1847.1	13.7%
51	2006	408.1	-0.9%	168.0	4.1%	72.7	2.5%	164.32	0.9%	134.6	3.4%	33.9	5.0%	1918.3	3.9%
52	2007	411.4	0.8%	161.2	-4.1%	75.2	3.5%	155.30	-5.5%	126.1	-6.3%	29.5	-12.9%	1812.9	-5.5%
53	Compounded Growth Rate		2.64%		4.01%		3.96%		4.05%		3.34%		7.98%		3.54%
54	Projected Growth Rate		2.50%		3.70%		3.70%		4.00%		3.50%		3.50%		3.40%
55	2008	423.5		174.8		76.1		184.5		142.7		33.4		2021.7	
56	2009	434.1		181.3		78.9		191.1		146.3		34.5		2090.4	
57	2010	444.9		188.0		81.8		197.7		150.0		35.8		2161.5	
58	2011	456.0		194.9		84.8		204.3		153.6		37.0		2235.0	
59	2012	467.4		202.1		88.0		211.0		157.2		38.3		2310.9	
60	2013	479.1		209.6		91.2		217.7		160.9		39.6		2389.5	
61	2014	491.1		217.4		94.6		224.3		164.5		41.0		2470.8	
62	2015	503.4		225.4		98.1		231.0		168.2		42.5		2554.8	
63	2016	516.0		233.8		101.7		237.6		171.8		43.9		2641.6	
64	2017	528.9		242.4		105.5		244.3		175.5		45.5		2731.4	

APPENDIX E – CALCULATE NEW COMPOUND GROWTH RATE (10 YEAR)



2014 - SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	Lakes Region %Difference	<= Adjustment for Webster Valve	<= New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	<= Adjustment for Safran & TurboCar	<= New Area Forecast	Manchester (MW)	Manchester %Difference	<= Adjustment for Velcro	<= New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

YEAR	Portsmouth (MW)	Portsmouth %Difference	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	CVEC (MW)	CVEC %Difference	PSNH [1] (MW)	PSNH [1] %Difference
2002	211.1	1.5%	391.7	4.7%	140.6	2.1%	-		1689	4.0%
2003	213.3	1.0%	381.1	-2.7%	146.5	4.2%	-		1677	-0.7%
2004	213.7	0.2%	368.5	-3.3%	138.7	-5.3%	29.1		1625	-3.1%
2005	250.1	17.0%	411.8	11.8%	161.4	16.4%	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	408.1	-0.9%	171.0	5.9%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	411.4	0.8%	164.2	-4.0%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	409.2	-0.5%	168.8	2.8%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	374.8	-8.4%	158.5	[illegible]	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	394.0	5.1%	173.2	9.3%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	397.5	0.9%	167.7	-3.2%	[illegible]	2.6%	1888.5	1.7%
2012	260.4	-0.2%	385.3	-3.1%	160.7	-4.2%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	397.9	3.3%	167.6	4.3%	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		0.14%		1.69%		1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%		1.00%		2.40%		1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%		0.50%		1.75%		[illegible]		1.25%
2014	287.5		409.5		186.0		[illegible]		[illegible]	
2015	297.0		413.6		190.4		[illegible]		[illegible]	
2016	306.8		417.8		195.0		[illegible]		[illegible]	
2017	316.9		422.0		199.7		[illegible]		[illegible]	
2018	327.3		426.2		204.5		35.4		2096.0	
2019	334.7		428.3		208.1		35.8		2122.2	
2020	342.2		430.4		211.7		36.3		2148.7	
2021	349.9		432.6		215.4		36.7		2175.5	
2022	357.8		434.8		219.2		37.2		2202.7	
2023	365.9		436.9		223.0		37.6		2230.3	

APPENDIX F - CALCULATE NEW COMPOUND GROWTH RATE (OTHER THAN 10 YEARS)

2014 - SUMMER PEAK LOAD FORECAST

Row	YEAR	Lakes Region (MW)	Lakes Region %Difference	<== Adjustment for Webster Valve	<== New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	<== Adjustment for Safran & TurboCar	<== New Area Forecast	Manchester (MW)	Manchester %Difference	<== Adjustment for Velcro	<== New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
13	2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
14	2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
15	2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
16	2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
17	2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
18	2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
19	2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
20	2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
21	2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
22	2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
23	2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
24	2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
25	Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
26	Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
27	Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
28	2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
29	2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
30	2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
31	2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
32	2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
33	2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
34	2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
35	2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
36	2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
37	2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

Row	YEAR	Portsmouth (MW)	Portsmouth %Difference	Nashua/Milford (MW)	Nashua/Milford %Difference	UES/Seacoast [2] (MW)	UES/Capital [2] (MW)	UES/Capital %Difference	CVEC (MW)	CVEC %Difference	PSNH [1] (MW)	PSNH %Difference
51	2002	211.1	1.5%	391.7	4.7%	[illegible]	118.6	6.8%	-		1689	4.0%
52	2003	213.3	1.0%	381.1	-2.7%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1677	-0.7%
53	2004	213.7	0.2%	368.5	-3.3%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1625	-3.1%
54	2005	250.1	17.0%	411.8	11.8%	[illegible]	[illegible]	[illegible]	[illegible]	11.1%	1847.1	13.7%
55	2006	267.5	7.0%	408.1	-0.9%	[illegible]	[illegible]	3.0%	33.9	5.0%	1918.3	3.9%
56	2007	254.2	-5.0%	411.4	0.8%	[illegible]	125.3	-6.5%	29.5	-12.9%	1812.9	-5.5%
57	2008	255.1	0.4%	409.2	-0.5%	[illegible]	128.8	2.8%	30.5	3.3%	1811.8	-0.1%
58	2009	236.6	-7.3%	374.8	-8.4%	[illegible]	120.5	-6.5%	28.9	-5.3%	1734.8	-4.3%
59	2010	256.1	8.2%	394.0	5.1%	[illegible]	130.9	8.6%	31.3	8.4%	1857.5	7.1%
60	2011	260.8	1.8%	397.5	0.9%	[illegible]	131.4	0.4%	32.1	2.6%	1888.5	1.7%
61	2012	260.4	-0.2%	[illegible]	[illegible]	[illegible]	123.1	-6.3%	27.1	-15.5%	1793.3	-5.0%
62	2013	262.2	0.7%	[illegible]	[illegible]	[illegible]	131.5	6.8%	30.7	13.2%	1889.2	5.3%
63	Compounded Growth Rate		2.09%		0.14%			1.02%		1.10%		1.02%
64	Adjusted Growth Rate (Years 1-5)		3.30%		1.00%			[illegible]		1.40%		1.50%
65	Projected Growth Rate (Years 6-10)		2.25%		0.50%			[illegible]		1.25%		1.25%
66	2014	287.5		409.5		[illegible]	[illegible]		[illegible]		1974.8	
67	2015	297.0		413.6		[illegible]	[illegible]		[illegible]		[illegible]	
68	2016	306.8		417.8		[illegible]	[illegible]		[illegible]		[illegible]	
69	2017	316.9		422.0		[illegible]	[illegible]		[illegible]		[illegible]	
70	2018	327.3		426.2		204.5	[illegible]		[illegible]		[illegible]	
71	2019	334.7		428.3		208.1	146.2		35.8		2122.2	
72	2020	342.2		430.4		211.7	147.9		36.3		2148.7	
73	2021	349.9		432.6		215.4	149.9		36.7		2175.5	
74	2022	357.8		434.8		219.2	151.2		37.2		2202.7	
75	2023	365.9		436.9		223.0	152.9		37.6		2230.3	

Nashua/Milford

Nashua/Milford	%Difference
391.7	
381.1	
368.5	
411.8	
408.1	-0.9%
411.4	0.8%
409.2	-0.5%
374.8	-8.4%
394.0	5.1%
397.5	0.9%
385.3	-3.1%
397.9	3.3%
409.5	
413.6	
417.8	
422.0	
426.2	
428.3	
430.4	
432.6	
434.8	
436.9	

11 years prior peak

10 years prior peak DO NOT USE (Low Point)

Historical Peak

5 year peak

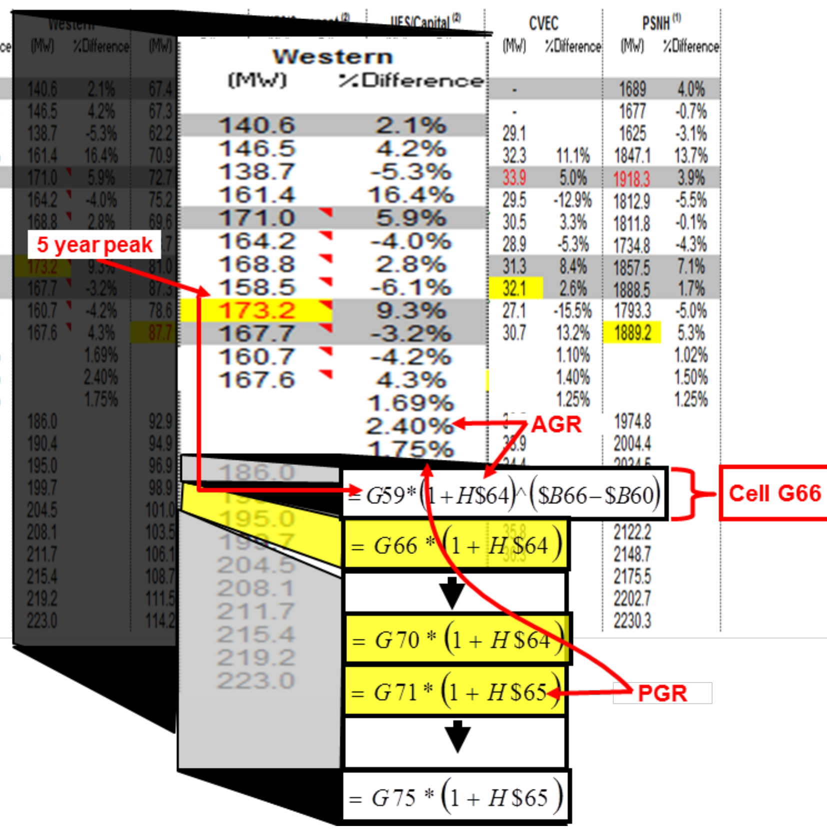
$$= Power\left(\frac{E\ 62}{E\ 51}, \frac{1}{B\ 62 - B\ 51}\right) - 1$$

APPENDIX G - CALCULATE PROJECTED GROWTH

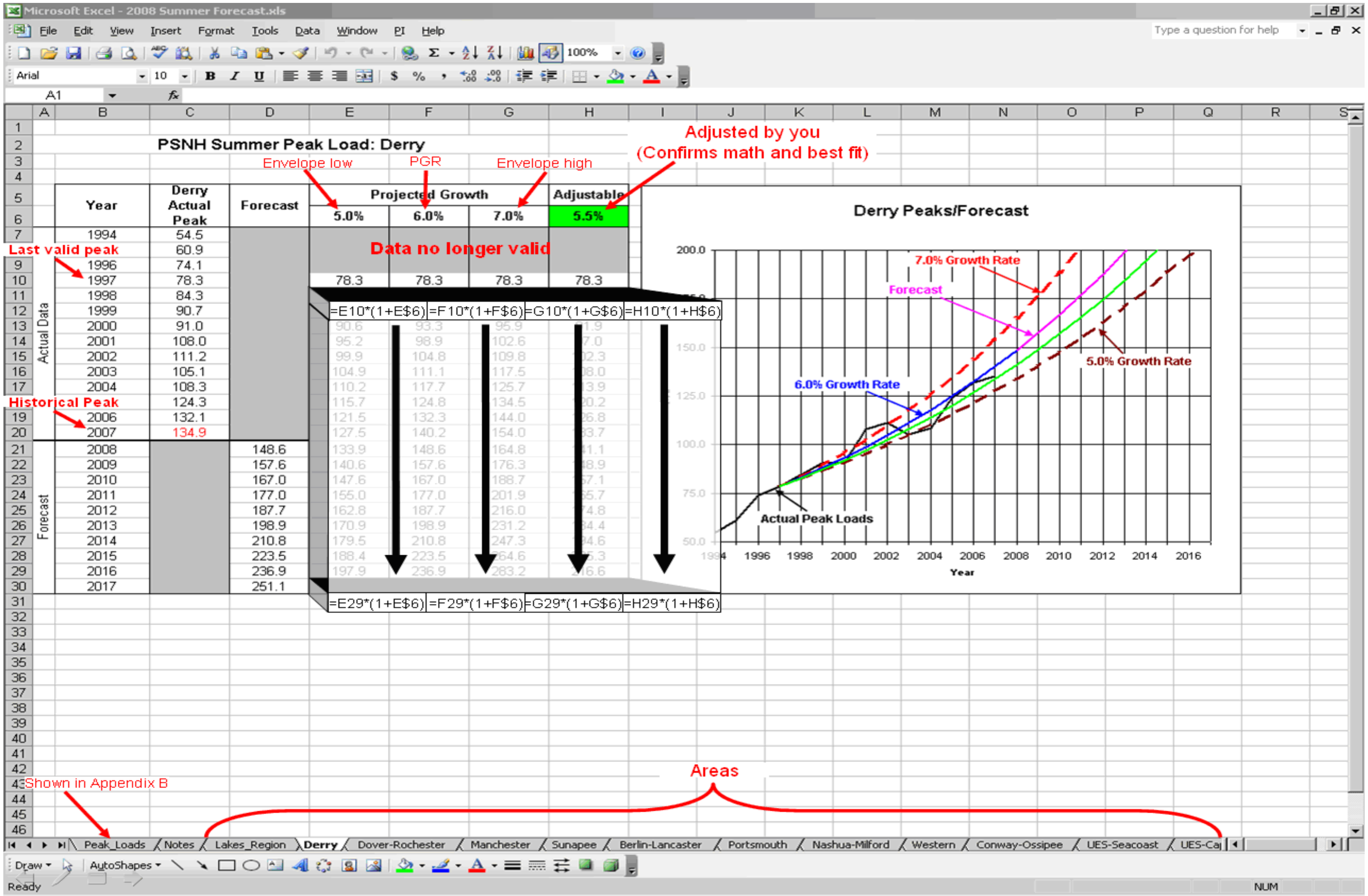
2014 - SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	Lakes Region %Difference	<= Adjustment for Webster Valve	<= New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	<= Adjustment for Safran & TurboCar	<= New Area Forecast	Manchester (MW)	Manchester %Difference	<= Adjustment for Velcro	<= New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

YEAR	Portsmouth (MW)	Portsmouth %Difference	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	(MW)	UES/Capital (2)	CVEC (MW)	CVEC %Difference	PSNH (1) (MW)	PSNH (1) %Difference
2002	211.1	1.5%	391.7	4.7%	140.6	2.1%	67.4	[illegible]	-		1689	4.0%
2003	213.3	1.0%	381.1	-2.7%	146.5	4.2%	67.3	[illegible]	-		1677	-0.7%
2004	213.7	0.2%	368.5	-3.3%	138.7	-5.3%	62.2	[illegible]	29.1		1625	-3.1%
2005	250.1	17.0%	411.8	11.8%	161.4	16.4%	70.9	[illegible]	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	408.1	-0.9%	171.0	5.9%	72.7	[illegible]	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	411.4	0.8%	164.2	-4.0%	75.2	[illegible]	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	409.2	-0.5%	168.8	2.8%	69.6	[illegible]	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	374.8	-8.4%	158.5	-6.1%	[illegible]	[illegible]	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	394.0	5.1%	173.2	9.3%	81.0	[illegible]	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	397.5	0.9%	167.7	-3.2%	87.3	[illegible]	32.1	2.6%	1888.5	1.7%
2012	260.4	-0.2%	385.3	-3.1%	160.7	-4.2%	78.6	[illegible]	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	397.9	3.3%	167.6	4.3%	87.7	[illegible]	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		0.14%		1.69%				1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%		1.00%		2.40%				1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%		0.50%		1.75%				1.25%		1.25%
2014	287.5		409.5		186.0		92.9	[illegible]	[illegible]		1974.8	
2015	297.0		413.6		190.4		94.9	[illegible]	[illegible]		2004.4	
2016	306.8		417.8		195.0		96.9	[illegible]	[illegible]		[illegible]	
2017	316.9		422.0		199.7		98.9	[illegible]	[illegible]		[illegible]	
2018	327.3		426.2		204.5		101.0	[illegible]	[illegible]		[illegible]	
2019	334.7		428.3		208.1		103.5	[illegible]	[illegible]		2122.2	
2020	342.2		430.4		211.7		106.1	[illegible]	[illegible]		2148.7	
2021	349.9		432.6		215.4		108.7	[illegible]	[illegible]		2175.5	
2022	357.8		434.8		219.2		111.5	[illegible]	[illegible]		2202.7	
2023	365.9		436.9		223.0		114.2	[illegible]	[illegible]		2230.3	



APPENDIX H - UPDATE AREA CHARTS AND GRAPHS



Year	Derry Actual Peak	Forecast
1994	54.5	
	60.9	
1996	74.1	
1997	78.3	
1998	84.3	
1999	90.7	
2000	91.0	
2001	108.0	
2002	111.2	
2003	105.1	
2004	108.3	
	124.3	
2006	132.1	
2007	134.9	
2008		148.6
2009		157.6
2010		167.0
2011		177.0
2012		187.7
2013		198.9
2014		210.8
2015		223.5
2016		236.9
2017		251.1

ED-3002 Distribution System Planning and Design Criteria Guidelines

I. PURPOSE

To establish guidelines to assist in planning and designing a distribution system that meets customer needs and regulatory requirements.

II. AREAS/PERSONS AFFECTED

This procedure applies to:

- Energy Delivery - system planning and design personnel

III. POLICY

It is the policy of PSNH:

A. To provide a reliable, cost effective, and efficient distribution system to meet customer needs while meeting regulatory requirements.

B. To insure adequate power distribution capacity during all times including normal summer and winter **peak load conditions**.

C. To examine **contingent** outages of substation equipment and circuits to identify areas subject to risk.

D. To insure a consistent approach to the planning for expansion and enhancement of the local area system.

E. To use sound engineering judgment when recommending construction for long term solutions when the design guidelines are exceeded.

F. To design the 34.5 kV distribution system to maximize performance and minimize cost by adhering to design criteria as outlined in this procedure.

IV. DEFINITIONS

Throughout the guideline, defined terms appear in bold and have a specific definition, which can be found in Appendix A.

V. OVERVIEW

This Operating Procedure provides distribution system design and planning guidelines for the 34.5kV and below systems. The 115kV and 345kV transformation to 34.5kV is included.

It is the intent of this guideline to promote the development of long term system solutions based on sound engineering and financial judgment. Short-term solutions **shall** be utilized only when prudent in the long-term planning of the system.

VI. PERIODIC REVIEW OF GUIDELINE

The Procedure Owner is responsible for maintaining this guideline and keeping current with good engineering design practices. The Procedure Owner for this Energy Delivery Procedure is the Manager of System Planning and Strategy or designee.

Annually, the Procedure Owner **shall** review design guideline for conformance to standard engineering practices and industry criteria to determine if the guideline **shall** be revised, rewritten, or cancelled.

As required, the Procedure Owner **shall** recommend changes to the Director of Energy Delivery. If approved by the Director, the Procedure Owner **shall** change the Procedure in accordance with AP-2001 Writing and Publishing Procedures.

VII. GUIDELINES

A. Normal Operation

Normal Operation is how the system is designed to operate during **peak load conditions**. The system **shall** be designed such that during normal operation no switching is required to maintain equipment within its normal thermal ratings.

For design purposes, the system **shall** be capable of serving native PSNH load during **peak load conditions** without relying on the facilities of customers or neighboring utilities unless in accordance with a specific contract.

Areas that may require system enhancements for Normal Operation are identified when **distribution power transformers** are loaded to within 85% of their **TFRAT** (transformer rating). Those areas will be specifically evaluated in order to determine proper budget and construction schedule such that system enhancements are in place the year prior to distribution power transformers exceeding their TFRAT. Refer to ED-3023, Appendix B, for guidance.

No load loss **shall** be permitted under normal Summer or Winter **peak load conditions**.

Each **system generator** will be modeled on and off during **peak load conditions** to assure adequate supply to the area. One generating unit at a time or the largest unit at a facility will be removed from the system model to examine the effect.

Distribution circuits to which **Independent Power Producers (IPP)** are connected will be designed to carry load in accordance with IPP contractual guidelines. IPP will be modeled on, off, and at varying power factors in accordance with the generator capabilities.

The use of **dispatchable peak shaving generation** as defined in Appendix A is acceptable for managing peak load issues in specific locations to manage capital investments on the system.

Known common supply conditions for generation facilities will be considered for impact on the system. This includes the effect of drought on all hydro-electric generation in an area, common fuel/gas supplies for multiple generation units, air emission standard constraints, etc.

B. Contingent Operation

Contingent Operation is the result of the failure of equipment during **peak load conditions**. The following **contingencies shall** be examined for system impact during **peak load conditions**.

1. Loss of 34.5 kV line breaker.
2. Loss of a **distribution power transformer**.
3. Loss of radial transmission lines.
4. Loss of non-radial transmission lines.
5. Loss of **dispatchable peak shaving generation**.

Each **system generator** will be modeled on and off during Contingent Operations. The reliability and ability to utilize the generation during **peak load conditions** will be examined in the event that a specific generating facility supports the system during Contingent Operation.

During Contingent Operation some loss of power to customers (load isolation) will be accepted at the time of **peak load conditions**. The following guidelines **shall** be used to determine the level of severity and need for construction:

1. The load isolation does not exceed 30 MVA and the duration of the outage does not exceed 24 hours.
2. **Load block transfers** on the 34.5kV system are an acceptable means for reducing exposure and typically **shall** not exceed three.

This design criteria recognizes that most PSNH transformers can be backed up by a mobile transformer or faulted circuits can usually be repaired in less than twenty-four hours unless under very adverse conditions.

C. Voltage Regulation

Power delivery systems **shall** maintain acceptable voltage levels to all customers under the conditions for which the power delivery system is designed. This voltage **shall** be maintained during all loading periods in addition to Contingent Operations.

Acceptable primary 34.5 kV bus voltage levels modeled **shall** be maintained at all locations under Normal and Contingent Operations for all load levels. Planning for these operations **shall** recognize where 34.5 kV load is regulated and unregulated (not including the 34.5 kV transformer LTC at **Bulk Power Facilities** as regulation):

1. **Regulated Load:** The acceptable voltage range is 95 – 105% under normal conditions. During **contingencies** voltage levels may drop no lower than 92% in a localized area. Where a customer is responsible for supplying its own voltage regulation, the acceptable voltage range is 90% - 110%.

2. **Unregulated Load:** The acceptable voltage range is 97.5 - 105% under normal conditions. During **contingencies** voltage levels may drop no lower than 95% in a localized area.

The voltage at customer service terminals **shall** not exceed those minimum and maximum values as outlined in the New Hampshire Code of Administrative Rules PUC 304.02 Voltage Variation, revised October 2005, or latest revision thereof.

NOMINAL VOLTAGE	MINIMUM VOLTAGE	MAXIMUM VOLTAGE
120	114	126
240/120	228/114	252/126
208Y/120	198Y/114	218Y/126
240	228	252
480Y/277	456Y/263	504Y/291
480	456	504
600	570	630

D. Power Factor

The power factor during normal operation **shall** be maintained at levels which limit reactive current flow on the system and maintain proper voltage. Additionally, PSNH **shall** strive for a **load power factor** which satisfies ISO-NE Operating Procedure No. 17. This contains the methodology for developing the ranges of acceptable **load power factor** at the point of interconnection to the transmission system.

PSNH **shall** strive to maintain unity (1.00) power factor at 34.5kV line breakers during **peak load conditions**. Substation capacitors at 34.5kV and above **shall** be designed as required primarily to compensate for transformer losses in accordance with OP17.

The consideration of power factor correction guidelines **shall** include all load levels and **contingent** operation. The 34.5kV and below circuits **shall** be modeled and designed to maintain distribution power factor (p.f.) ranges in accordance with the following table:

Load Level(% of Peak)	Minimum p.f.	Maximum p.f.
80-100%	.98 lag	1.00
65-80%	.95 lag	1.00
up to 65%	.94 lag	1.00

The location, control device, and size of capacitor banks **shall** be determined in accordance with good engineering judgment and operation of the system.

E. System Protection

Except for transformers and buses at **bulk distribution facilities**, distribution primary elements **shall** normally be supplied with one system of protection, although remote devices may provide some inherent backup. Transformers and buses at **bulk distribution facilities shall** normally be supplied with two systems of protective relays.

Protective provisions **shall** be included with all distribution system designs to limit exposure to the public, personnel, and equipment from abnormal events and conditions. Control provisions **shall** be included with all distribution system designs to allow the system to operate in a manner consistent with the intent of planning and operating criteria. Protection and Controls Engineering **shall** be included early in the system planning process such that the related protection and control designs may be designed to support all intended system operating modes. The approach will avoid loading, operating, and/or protection limitations, which could otherwise prevent the primary system from providing the desired support during critical periods.

The intent of system protection design guidelines is that the above **shall** apply to new installations. Existing equipment **shall** be reviewed, as appropriate, and brought into conformance with these guidelines where prudent.

F. Equipment Loading Limits

Substation Transformers: The Normal limit, computer calculated **TFRAT** rating, is the maximum equipment load rating without incurring loss of life above the design loading limit, adjusted for ambient conditions. Transformer loading under Normal and Contingent Operation **shall** not exceed the **TFRAT** ratings.

Conductors: Conductors **shall** be rated for Normal and Contingent Operation. Under Normal Operation the conductors will be loaded within the normal rating limit of the conductors. The normal rating limit is the maximum equipment loading without incurring loss of life above the design-loading limit, adjusted for ambient conditions. During Contingent Operation the conductors will be within the emergency-rating limit of the conductors. The emergency-rating limit may involve loss of life or loss of tensile strength and is for Contingent Operation only. Any normal rating limit exceeded under Normal Operation **shall** be resolved by making prudent system changes or system enhancements to get the conductor within normal ratings. Any emergency-rating limit exceeded under Contingent Operation will result in switching, load isolation, and/or construction.

G. Economic

Economic evaluation of various alternatives will be made using the 'revenue requirements' method, or other economic evaluation methods as directed by management. Various alternatives **should** be projected to the end of their useful lives for making comparisons. System Planning and Strategy **should** determine operating and maintenance costs and useful life for purposes of economic studies.

H. Load Forecasts

Short and long-range load forecasts for the Company can be obtained from the System Planning and Strategy Department. These engineers will develop forecasts for localized planning based on load growth history and field input while working within the confines of the Company forecasts.

I. Substation Design

1. Transformers with secondary voltages of 34.5kV and below **shall** have secondary breakers. Each circuit fed from the substation **shall** have a designated circuit breaker.

   EXCEPTION: If only one circuit is fed from the substation, the transformer breaker may be utilized as the circuit breaker. Provisions **shall** be made for circuit breakers for future circuit additions.

2. Bus tie breakers **shall** be incorporated into substations with two or more transformers.

a. Existing substations **shall** be modified when major construction takes place in the substation or a specific project is proposed for this purpose.

b. Existing single transformer substations **shall** be designed to include the bus tie breaker when a second transformer is added.

c. New substations **shall** be designed with provisions for a future bus tie breaker if only one transformer is being constructed.

d. The bus tie breaker **should** be operated normally open at the substation.

3. Standard wire size for substation take-off construction **should** not exceed 477 kcmil ACSR.

J. 34.5 kV Circuit Design

1. Circuits looped between two substations

a. Standard wire size for all backbone circuits **shall** be 477 kcmil ACSR.

b. Looped circuit may have a normally open point between the two substations, in which case:
   i. Each circuit **should** be limited to a peak load of 400 amps at each substation.
   ii. The total load on the looped circuit(s) **shall** be no greater than 800 amps.

2. Three Phase Radial Circuits

a. Standard wire size for a backbone radial circuit **should** be 477 kcmil ACSR. If the potential for the radial circuit to become part of a loop system is greater than 10 years, 1/0 ACSR is an acceptable wire size.

b. Three phase 34.5 kV radial circuits consisting of primarily residential load **should** be limited to:
   i. 200 amps OR;
   ii. 2500 customers (per **DSEM** 02.303) OR;
   iii. 6 miles of three phase backbone (per **DSEM** 02.101) OR;
   iv. 50 miles of line for the entire circuit

c. An alternate/additional source to the radial circuit **should** be provided when any of the constraints in 2.b.i.-iv. above are exceeded. A separate source is preferred if available.

3. Single phase circuits

a. Standard wire size for a single phase circuit **should** be 1/0 ACSR.

b. A single phase circuit design **should** incorporate a recloser to protect a circuit with over 200 customers instead of a fuse.

c. Load **shall** be limited to 70 amps, maximum.

K. Conversion to 34.5kV

1. Circuits **shall** be reconductored if existing conductor being converted is smaller than 1/0 copper.

VIII. APPENDIX

Appendix A – Definitions
Appendix B - References

IX. ED-3002 REVISION HISTORY

Revision Number	Date	Reason
Rev 0	01/10/03	Original issue
Rev 1	10/04/05	
Rev 2	06/27/06	
Rev 3	06/28/09	Revised to incorporate distribution peak shaving – DCI Team recommendations
Rev 4	09/12/11	Correction of section VII, A.

ED-3002 APPENDIX A - DEFINITIONS

A. **Bulk Distribution Facilities** - Any distribution facility with a primary voltage 115 kV or greater.

B. **Contingency** (or **Contingencies**) - A failure of a single piece of equipment, which may require a reconfiguration of the system to restore load to customers. This includes a **distribution power transformer**, circuit, or circuit breaker.

C. **Dispatchable Peak Shaving Generation** – Electric power generators located at substations or other strategic locations to manage potentially overloaded transformers at peak load conditions. Examples: Combustion turbines, micro-turbines, reciprocating engines, or any other source of electric power which can be switched on or off as required and under the control of PSNH.

D. **Distribution Power Transformer** - Transformers supplying load at distribution levels including 34.5kV, 12.47kV, 4.16kV, and equivalent voltages.

E. **DSEM** - Northeast Utilities' Distribution System Engineering Manual

F. **Independent Power Producers (IPP)** – Non-PSNH generation interconnected to the PSNH system that meets the FERC definition of being a qualifying facility either by operating as a cogenerator or by producing generation with a renewable fuel source.

G. **Load Block Transfers** - Transfers of load between system areas that can be performed by operation of breakers and switches controlled by or under the direction of PSNH's Electric System Control Center (ESCC).

H. **Load Power Factor** - The **load power factor** is determined by adding real and reactive load at the transformation low side with transformer losses, generation below 115kV, and 115kV capacitors designated for system power factor correction. This methodology is defined in ISO-NE Operating Procedure No. 17.

I. **Peak Load Conditions** - The one-hour annual system and/or area peak MVA load for the season identified.

J. **Regulated Load** – Load that has voltage regulation at a 34.5kV primary voltage beyond the **Bulk Distribution Facility**. The system load is all beyond a PSNH voltage regulated source. Primary metered customers are considered **regulated load** because regulation is their responsibility in accordance with the Tariff.

K. **Shall** – An expression of command requiring conformance.

L. **Should** – An expression of condition which requires consideration but not immediate action.

M. **System Generation** - All generation on the PSNH System.

ED-3002 APPENDIX A - DEFINITIONS

N. <u>**TFRAT** Rating</u> - Maximum load on a **distribution power transformer** to utilize its capacity without overheating the equipment and causing damage that will reduce its normal life. **TFRAT** Rating is determined utilizing a computer program at PSNH. System Planning and Strategy maintains these records.

O. <u>**Unregulated Load**</u> – Load that has no voltage regulation at the 34.5 kV primary voltage beyond a **Bulk Distribution Facility**. The voltage of the system load is not regulated beyond the 34.5 kV point modeled for planning by System Planning and Strategy.

ED-3002 APPENDIX B - REFERENCES

January 2004 - Transmission Reliability Standards for Northeast Utilities

Decmeber 8, 2006 or most recent version - ISO-NE Operating Procedure No. 17 – Load Power Factor Correction

DSEM 02.10 Reliability General

DSEM 02.30 Automatic Sectionalizing Device Guidelines

DSEM 05.30 Contingency Planning

DSEM 10.20 Recloser Guide

DSEM 18.30 Feeders per Substation

ED-3023 - Procedure for Comprehensive System Planning Studies

2015 - SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	Lakes Region %Difference	<= Adjustment for Webster Valve	<= New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	<= Adjustment for Safran & TurboCa	<= New Area Forecast	Manchester (MW)	Manchester %Difference	<= Adjustment for Velcro	<= New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			101.5	-6.1%	145.4	3.1%			326.1	5.2%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			95.2	-6.1%	143.1	-1.6%			322.9	-1.0%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			98.4	3.3%	136.2	-4.8%			324.4	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			112.8	14.7%	162.3	19.2%			371.9	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			119.1	5.6%	169.1	4.2%			370.5	-0.4%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			125.1	5.0%	161.5	-4.5%			365.0	-1.5%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			120.7	-3.5%	156.1	-3.3%			378.4	3.7%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			109.4	-9.4%	156.8	0.5%			348.1	-8.0%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			120.2	9.9%	167.5	6.8%			377.1	8.3%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			122.7	2.1%	175.2	4.6%			380.6	0.9%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			115.5	-5.9%	160.9	-8.2%			368.0	-3.3%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			121.6	5.3%	172.4	7.2%			378.5	2.9%			41.5	11.9%	54.1	2.5%
2014	182.0	-0.3%			111.4	-8.4%	162.3	-5.9%			356.0	-6.0%			39.7	-4.3%	50.4	-6.8%
Compounded Growth Rate		1.19%				1.60%		1.57%				1.30%				0.98%		-2.63%
Adjusted Growth Rate (Years 1-5)		1.50%				2.00%		1.75%				1.80%				1.20%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				1.75%		1.75%				1.50%				1.00%		0.50%
2015	198.8		3.5	202.3	132.8		187.8		5.2	193.0	408.8		4	412.8	42.5		57.5	
2016	201.8		3.5	205.3	135.5		191.1		8.4	199.5	416.1		4	420.1	43.0		57.8	
2017	204.8		3.5	208.3	138.2		194.4		12.6	207.0	423.6		4	427.6	43.5		58.1	
2018	207.9		3.5	211.4	140.9		197.8		12.6	210.4	431.2		4	435.2	44.1		58.4	
2019	211.0		3.5	214.5	143.8		201.3		13.8	215.1	439.0		4	443.0	44.6		58.7	
2020	213.6		3.5	217.1	146.3		204.8		15	219.8	445.6		4	449.6	45.0		59.0	
2021	216.3		3.5	219.8	148.8		208.4		16.2	224.6	452.3		4	456.3	45.5		59.3	
2022	219.0		3.5	222.5	151.4		212.0		16.2	228.2	459.0		4	463.0	45.9		59.6	
2023	221.7		3.5	225.2	154.1		215.7		16.2	231.9	465.9		4	469.9	46.4		59.9	
2024	224.5		3.5	228.0	156.8		219.5		16.2	235.7	472.9		4	476.9	46.9		60.2	

YEAR	Portsmouth (MW)	Portsmouth %Difference	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	Conway/Ossipee (MW)	Conway/Ossipee %Difference	UES/Seacoast [2] (MW)	UES/Seacoast [2] %Difference	UES/Capital [2] (MW)	UES/Capital [2] %Difference	CVEC (MW)	CVEC %Difference	Eversource [1] (MW)	Eversource [1] %Difference
2002	211.1	1.5%	391.7	4.7%	140.6	2.1%	67.4	8.7%	142.8	5.8%	118.6	6.8%	-		1689	4.0%
2003	213.3	1.0%	381.1	-2.7%	146.5	4.2%	67.3	-0.1%	145.9	2.2%	118.8	0.2%	-		1677	-0.7%
2004	213.7	0.2%	368.5	-3.3%	138.7	-5.3%	62.2	-7.6%	135.3	-7.3%	114.4	-3.7%	29.1		1625	-3.1%
2005	250.1	17.0%	411.8	11.8%	161.4	16.4%	70.9	14.0%	162.9	20.4%	130.2	13.8%	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	408.1	-0.9%	171.0	5.9%	72.7	2.5%	170.6	4.7%	134.0	3.0%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	411.4	0.8%	164.2	-4.0%	75.2	3.5%	155.7	-8.7%	125.3	-6.5%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	409.2	-0.5%	168.8	2.8%	69.6	-7.4%	145.8	-6.4%	128.8	2.8%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	374.8	-8.4%	158.5	-6.1%	68.7	-1.3%	147.1	0.9%	120.5	-6.5%	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	394.0	5.1%	173.2	9.3%	81.0	17.9%	159.7	8.5%	130.9	8.6%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	397.5	0.9%	167.7	-3.2%	87.3	7.8%	167.4	4.9%	131.4	0.4%	32.1	2.6%	1888.5	1.7%
2012	260.4	-0.2%	385.3	-3.1%	160.7	-4.2%	78.6	-10.0%	154.5	-7.7%	123.1	-6.3%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	397.9	3.3%	167.6	4.3%	87.7	11.6%	166.2	7.6%	131.5	6.8%	30.7	13.2%	1889.2	5.3%
2014	249.3	-4.9%	375.5	-5.6%	152.9	-8.8%	80.8	-7.9%	151.9	-8.6%	126.0	-4.2%	31.1	1.3%	1773.4	-6.1%
Compounded Growth Rate		2.07%		0.13%		1.53%		2.44%		1.26%		0.93%		0.99%		0.94%
Adjusted Growth Rate (Years 1-5)		3.20%		0.50%		2.00%		1.80%						1.20%		1.30%
Projected Growth Rate (Years 6-10)		2.25%		0.50%		1.75%		1.80%						1.00%		1.00%
2015	295.8		405.5		187.5		93.8		184.7		140.3		33.7		1988.6	
2016	305.3		407.5		191.2		95.4		189.3		141.9		34.1		2014.5	
2017	315.1		409.6		195.1		97.2		193.7		143.6		34.5		2040.7	
2018	325.1		411.6		199.0		98.9		198.2		145.2		34.9		2067.2	
2019	335.5		413.7		202.9		100.7		202.4		146.9		35.3		2094.1	
2020	343.1		415.7		206.5		102.5		206.6		148.3		35.7		2115.0	
2021	350.8		417.8		210.1		104.3		210.1		149.6		36.0		2136.2	
2022	358.7		419.9		213.8		106.2		213.5		151.3		36.4		2157.5	
2023	366.8		422.0		217.5		108.1		217.4		153.0		36.7		2179.1	
2024	375.0		424.1		221.3		110.1		221.4		154.1		37.1		2200.9	

Northeast Utilities System TD PROCEDURE		**TD 190 Rev. 0** **Targeted Application of C&LM Measures to Meet Peak Load Planning Needs**	
Issue Date: 6/18/10	Effective Date: 6/25/10	Owner Department: **CL&P Customer Solutions** William Quinlan, Vice President Subject Matter Expert (SME) Name, Departments: **Conservation and Load Management (C&LM)** CL&P: Ronald J. Araujo, Manager, C&LM WMECO: Richard L. Oswald, Manager, C&LM **Marketing Support** PSNH: Gilbert E. Gelineau, Jr., Manager, Mkt. Support Responsible Person (RP) Name, Department: **CL&P Conservation and Load Management (C&LM)** Samuel R. Fankhauser, Sr. Energy Engineer	Applicability: **CT, MA, NH**

All changes to TD procedures are controlled by TD 001 "Writing, Revising, and Publishing Transmission and Distribution Procedures."

Roll Out Instructions:
Prior to initial use of this new procedure, each individual using this procedure is required to attend familiarization training provided by the appropriate SME.

Approvals: **CL&P**: ______________________
Name: **Jessica B. Cain**
Title: **Director, Customer Solutions**

WMECO: ______________________
Name: **Jennifer A. Schilling**
Title: **Director, Business Planning**

PSNH: ______________________
Name: **Terrance J. Large**
Title: **Director, Business Planning & Customer Support Services**

Procedure applicable only to NU companies for which an approval signature appears above.

Ensure you are using the current revision by verifying it against the controlled electronic copy located on the Distribution Engineering Standards Bookshelf or the Regulated Businesses Policies and Procedures Lotus Notes Database.

TABLE OF CONTENTS

ATTACHMENTS

1. INTRODUCTION

1.1 Objective

Provide instructions and administrative requirements for the following:

- Delay infrastructure replacement expenditures by using C&LM programs to aggregate 1 to 5 MW capacity savings over a 5-yr period within a designated target area delaying the need for a capital project to make existing plant last longer before capital costs associated with full replacement are necessary.

1.2 Applicability

The following is a list of the groups and the appropriate personnel having primary responsibilities with this procedure and its content.

1. 1st Main Group involved with this TD: CL&P VP, Energy Delivery Services; WMECO President and CEO; PSNH President and Chief Operating Officer;
   - A sub division of that group: CL&P Customer Solutions; WMECO Business Planning; PSNH Business Planning & Customer Support Services.
   - Another sub division of that group: Conservation and Load Management (C&LM) Departments at CL&P, and WMECO; and Marketing Support Department at PSNH.

The following divisional personnel will have specific responsibilities listed in this procedure:

1. Main Group Title of whom will be doing the steps with in this TD: Conservation and Load Management (C&LM) Departments at CL&P, WMECO; and the Marketing Support Department at PSNH
   - Title of personnel: Program Administrators

2. Organizations responsible for submitting requests to trigger use of the procedure: CL&P Asset Management, WMECO System Planning and PSNH Field Engineering Departments.

1.3 References

- NU Distribution Capital Investment Project

Supporting References
Documents that support performance of activities directed by this procedure:

- DSEM Section 05.20 Circuit Load Projections;
- Asset Management Departments at CL&P, System Planning Department at WMECO, and the Field Engineering Department at PSNH.

Supporting Programs and Databases
Programs and databases that support performance of activities directed by this procedure:

- DPUC/DPU/PUC Approved C&LM Programs at CL&P/WMECO/PSNH respectively.

1.4 Discussion

Procedure need was established by the NU Distribution Capital Investment (DCI) Project. Currently, there is no process link between NU operating companies and C&LM to address a distribution system "rapid results initiative" to delay need for capital addition.

The purpose of this procedure is to provide process guidance for targeted application of C&LM programs when requested by an NU operating company.

C&LM programs may facilitate delay of infrastructure replacement expenditures within a designated target area of concern identified by an NU operating company. To maximize potential for success, the aggregate MW savings requested needs to be modest, e.g., one to five MW and period of aggregation needs to be relatively long, e.g., ~five-yrs. This condition would normally occur within towns that have limited load growth.

A meeting with management representatives from Asset Management/System Engineering/Field Engineering and their respective C&LM/Marketing representatives shall be conducted on an annual basis to evaluate load projections and discuss potential target areas for feasibility assessment per Section 2.0 of this procedure.

For CL&P, PSNH and WMECO, this annual meeting shall occur in January. This allows all operating companies sufficient time for completion of feasibility studies in advance of the capital budgeting process.

For CL&P this is subsequent to issue of the Distribution Substation Plan (DSP), typically published in January. The objective of this meeting is to review proposed projects that address overloads on sub-stations and to review overloaded feeders from the Load Estimating and Planning (LEAP) report.

C&LM implementation of this procedure is initiated by a written request from NU operating company's Asset Management (CL&P) or System Planning (WMECO) or Field Engineering (PSNH) Department that identifies the geographical target area of concern with associated MW savings that need to be achieved during ~five-yrs duration. (See NOTE 1).

Specific Requests can be submitted to C&LM throughout the year. Attachment 1 lists the information required by Engineering in order to start the process.

NOTE 1

At CL&P this procedure is initiated by a written request from the Asset Management Department. At WMECO this procedure is initiated by a written request from the System Planning Department. At PSNH this procedure is initiated by a request from the Field Engineering Department.

NOTE 2

This procedure refers to "C&LM" Department and "C&LM" Programs throughout for all three utilities. This is consistent with the nomenclature at CL&P and WMECO. However, at PSNH the nomenclature used is "Marketing Support Department" and "Marketing and Conservation Programs." For purposes of this procedure the term "C&LM" is used for all three utilities.

NOTE 3

There are regulatory prerequisites that need to be considered and addressed by the Companies prior to implementing targeted application of C&LM Programs.

CL&P and WMECO – Preliminary review does not reveal explicit regulatory barriers to targeted application of C&LM Programs. However, a thorough review by NUSCO Legal/Regulatory is recommended prior to initiation of the C&LM Lever.

PSNH – Will need PUC approval prior to implementing C&LM Lever (see below).

Background - - Previously, PSNH's LCIRP indicated that the electric industry restructuring legislation prohibited allocation of System Benefit revenues in a targeted fashion. However, in the last session of the New Hampshire legislature, a change was made to the state law which had previously prohibited the use of System Benefits Charge funds for "targeted conservation, energy efficiency, and load management..." The kind of thing that this prevented was PSNH evaluating a heavily loaded distribution circuit and using SBC monies to fund a program "targeting" customers on this circuit for efficiency measures. The idea would be to reduce the load on the circuit and thereby reduce PSNH costs by delaying the need for circuit upgrades. With this recent change in the New Hampshire law, targeting (with SBC funds) is now an option -- but this option can only be implemented with explicit Commission approval.
(This technique has been used in other jurisdictions (e.g. see Efficiency Vermont's "geotargeting" - http://www.efficiencyvermont.com/pages/Common/GeoTargeting/).

For Information: The following is the full text of the applicable portion of New Hampshire HB 395 passed by the legislature and signed by the Governor during 2009.

(e) Targeted conservation***, energy efficiency,*** and load management programs and incentives that are part of a strategy to minimize distribution costs ***may*** be included in the distribution charge ***or the*** system benefits charge***, provided that system benefits charge funds are only used for customer-based energy efficiency measures, and such funding shall not exceed 10 percent of the energy efficiency portion of a utility's annual system benefits charge funds. A proposal for such use of system benefits charge funds shall be presented to the commission for approval. Any such approval shall initially be on a pilot program basis and the results of each pilot program proposal shall be subject to evaluation by the commission***.

2. INSTRUCTIONS

2.1 C&LM Department feasibility assessment of proposed target application of C&LM Programs request by NU Operating Company's Asset Management (CL&P) or System Planning (WMECO) or Field Engineering (PSNH) Departments.

Appropriate C&LM SME

2.1.1 ENSURE Operating Company's request for each targeted application of C&LM Programs includes the following information: **(Refer to Attachment 1 for detailed list).**

a. Geographic location and size of proposed priority target area.

b. Capacity savings goal (MW) required: Criteria (1 → 5 MW).

c. Time duration to aggregate (MW) savings: Criteria (~5-yrs).

2.1.2 SUBMIT request to designated C&LM Supervisor to PERFORM a feasibility assessment of the Operating Company's request.

Designated C&LM Supvr

2.1.3 PERFORM a feasibility assessment of the Operating Company's request with consideration of all the following: **(Refer to Attachment 2 Checklist).**

a. GATHER all applicable information pertaining to the proposed target area including market size and types of customers, status of previous C&LM measures implemented, etc.

b. DETERMINE whether the proposed target area has sufficiently high % of C/I customers to be successful in attaining capacity savings goal.

c. DETERMINE status of C&LM budget for C/I programs and ability to support target area capacity savings objective.

d. DETERMINE if economy in proposed target area is conducive to C/I customers initiating projects needed to support capacity savings objective.

e. GATHER available information from the Connecticut Clean Energy Fund (CCEF) or equivalent agencies in WMECO or PSNH territory pertaining to the level of PV installations planned for installation within the proposed target area during the requested time duration.

f. GATHER available information from the appropriate C&LM Group pertaining to the level of existing Load Response under contract within the proposed target area during the requested time duration.

g. DETERMINE if there are any other activities identified or under contract that will serve to reduce MW demand within the proposed target area during the requested time. For example: Emergency Generators; "Green City" initiatives; "Marshfield" type pilot programs; etc.

Designated C&LM Supvr

2.1.4 REVIEW completed feasibility assessment with C&LM SME.

Appropriate C&LM SME

2.1.5 PROVIDE C&LM's feasibility assessment results and recommendations to the Operating Company Requestor during an annual meeting with management representatives from Asset Management/System Planning/Field Engineering and C&LM/Marketing. The objective of this annual meeting is to establish agreement on recommendations for proposed targeted application of C&LM programs.

For CL&P, PSNH and WMECO, this annual meeting shall occur during May-June time frame subsequent to completion of feasibility assessment.

For Specific Requests submitted throughout the year, C&LM shall respond via email within 45-days of receiving the request.

a. If feasibility assessment is a "Go" determination, PROCEED with Step 2.2.

b. If feasibility assessment is "No-Go, Do Not proceed with Step 2.2.

Note: If C&LM savings can be achieved, at a minimum the feasibility assessment shall include the MW savings estimated by year.

2.2 Implement Proposed Target Application of C&LM Programs.

Appropriate C&LM SME

2.2.1 ASSIGN designated C&LM Supervisor to IMPLEMENT proposed target application of C&LM Programs.

2.2.2 PROVIDE designated C&LM Supervisor with copy of results of the feasibility assessment of the Operating Company's request.

Designated C&LM Supvr

2.2.3 ESTABLISH core team of C&LM staff required to support implementation of proposed target application of C&LM Programs.

2.2.4 PERFORM target application of C&LM Programs with consideration of all the following elements:

a. DEVELOP targeted area marketing plan to meet the objective. Planning and implementation of the marketing plan will need to include Account Executive's (AE's) associated with the proposed target area.

b. DEVELOP appropriate tracking and reporting system to support monitoring, tracking, and reporting MW savings accrued within the proposed target area during the prescribed timeframe.

c. DEVELOP and IDENTIFY MW milestones to be reported during the prescribed timeframe.

d. MONITOR, TRACK and REPORT MW Savings Progress on a Quarterly Basis to ensure capacity savings objective is met within prescribed timeframe.

e. MAINTAIN close communication with C&LM Management; Operating Company's Asset Management or Field Engineering Department; and Load Forecasting Department during progress of the project to assess milestone progress, changes in the target area, etc.

End of Section

3. SUMMARY OF CHANGES

Revision 0 (This is a new Procedure). Effective Date 6/25/10

Attachment 1

Engineering Information Requirements Needed for C&LM Analysis

When requesting a feasibility assessment for a target area the following information should be included in the request and recorded in the project database of the respective operating company, i.e., Asset Management (CL&P), System Planning (WMECO), Field Engineering (PSNH).

- **Name of the substation, including:**
  - Nomenclature
  - Towns supplied by the substation
  - Circuits impacted in which load relief could help delay the proposed project.

- **Estimate year of load relief needed.**

- **One-line Map with the proposed relief area highlighted.**

- **Provide a brief description of the geographic area (include information that would provide C&LM with the primary drivers for your request. Include any known planned developments.**

- **For a Substation Project:**
  - Provide a total minimum target for the MW load relief needed in order to delay the project.

    (Example: If the substation normal peak load is 60 MW with a load growth of 1%, you may ask for an estimated load reduction expectation of about 0.6 MW to delay the project at least 1-year. Or, if any C&LM savings could help defer segments of the project, just note that any load relief would help to delay the project.

- **For a Feeder Project or Substation Project in which targeted efforts could help:**
  - A target MW load relief required to delay your proposed project. Or, if any C&LM savings could help delay segments of the project, just note that any load relief would help to delay the project.
  - List the circuits and/or circuit segments for which targeted C&LM could potentially delay the need for a feeder project. Specify the MW load reduction needed. To target a particular portion of the circuit, define the targeted area using the device sequence ID, street information, pole # and nomenclature (if appropriate).

Attachment 2

Feasibility Assessment Checklist

C&LM shall PERFORM a feasibility assessment of the Operating Company's request for a targeted application of C&LM Programs with consideration of all the following items:

a. GATHER all applicable information pertaining to the proposed target area including market size and types of customers, status of previous C&LM measures implemented, etc.

b. DETERMINE whether the proposed target area has sufficiently high % of C/I customers to be successful in attaining capacity savings goal.

c. DETERMINE status of C&LM budget for C/I programs and ability to support target area capacity savings objective.

d. DETERMINE if economy in proposed target area is conducive to C/I customers initiating projects needed to support capacity savings objective.

e. GATHER available information from the Connecticut Clean Energy Fund (CCEF) or equivalent agencies in WMECO or PSNH territory pertaining to the level of PV installations planned for installation within the proposed target area during the requested time duration.

f. GATHER available information from the appropriate C&LM Group pertaining to the level of existing Load Response under contract within the proposed target area during the requested time duration.

g. DETERMINE if there are any other activities identified or under contract that will serve to reduce MW demand within the proposed target area during the requested time. For example: Emergency Generators; "Green City" initiatives; "Marshfield" type pilot programs; etc.