# Public Service Company of New Hampshire

# Least Cost Integrated Resource Plan

# September 30, 2010

Public Service
of New Hampshire

A Northeast Utilities Company

## Table of Contents

# I. Executive Summary

Public Service Company of New Hampshire's (PSNH or "the Company") 2010 Least Cost Integrated Resource Plan (LCIRP) is filed pursuant to RSA 378:38. PSNH's previous LCIRP was filed on September 30, 2007.

## A. Current Planning Environment

The environment in which PSNH operates has undergone significant changes since the last LCIRP filing. There has been a heightened focus on renewable energy initiatives at the federal, state, and local levels. Renewable projects are facing financial challenges due to the tightening of funding availability and a constrained and limited transmission system. However, PSNH continues to make progress on supporting the environment through renewable energy options and providing customers with a cleaner generation fleet. The recession that affected the United States and New Hampshire has also had an impact on PSNH's energy sales and peak demands. As a result of the recession, PSNH's delivery sales plummeted, peak loads dropped, housing permits declined resulting in fewer new customers, and market energy prices dropped significantly. As a result of lower energy prices, competitive suppliers capitalized on the opportunity to serve more customers and PSNH's quantity of energy served on its default energy service (Energy Service or ES) rate dropped accordingly resulting in a lower supply resource gap for PSNH's default energy service customers. This change in the resource gap has changed the need for additional resources to supply default energy service customers as compared to the previous LCIRP filed in 2007.

### A.1. "Green" Policies and Initiatives

There are several policies and initiatives surrounding climate change, energy efficiency, and renewable energy currently ongoing that affect PSNH's business.

<u>Climate Change/Energy Efficiency</u>

In December 2007, the Governor established a Climate Change Policy Task Force and charged the Task Force with developing a Climate Action Plan for New Hampshire. PSNH is an appointed member of the task force. In October 2008, the Energy Efficiency & Sustainable Energy Board (EESE) was created by the New Hampshire legislature "to promote and coordinate energy efficiency, demand response, and sustainable energy programs in the state." PSNH is involved in the EESE Board and participates on various subcommittees. Both of these initiatives are aimed at developing solutions to reduce greenhouse gases through policy change and reduced fossil fuel consumption. In January 2009, the Commission issued a study performed by GDS Associates to identify the different levels of achievable energy efficiency in New Hampshire. This study is analyzed in depth in the demand-response section in this report.

The first compliance period in New Hampshire for the Regional Greenhouse Gas Initiative (RGGI) began in January 2009. In December 2008, New Hampshire participated in the first RGGI auction where the clearing price of a $CO_2$ allowance was $3.38/ton. One year later, the clearing price was $2.19/ton. As of December 2009, the state has received $15 million in allowance auction revenues. The Office of Sustainable Energy disbursed the $15 million from the Greenhouse Gas Emissions Reduction Fund (GHGERF) in two phases. Phase one awards supported foundational programs and phase two awards supported primarily energy efficiency programs and revolving loan funds. The New Hampshire CORE Program received $7.6 million in funding, with $3.3 million going to PSNH. As a result of that increased funding, expanded energy efficiency programs were funded in the beginning of 2010 in accordance with some of the recommendations outlined in the GDS Associates report. However, in June 2010, the New Hampshire Legislature voted to use $3.1 million of the RGGI fund to help balance the state's budget shortfall.

In January 2010, the New Hampshire Legislature passed Senate Bill 300 which changed the allocation of the 3.3 mills per kWh System Benefits Charge (SBC) such that 1.8 mills per kWh is allocated to the Electric Assistance Program (EAP) and 1.5 mills per kWh is allocated to energy efficiency programs. This change resulted in one time realignment of budgets in PSNH's CORE Programs. PSNH was able to reallocate funding from other sources to cover most of the gap left by the reallocation; however, this was a one-time adjustment. If the SB 300 allocation is extended beyond the scheduled June 30, 2011 date, significant cutbacks will need to be made in services delivered under the CORE Programs funded by the System Benefits Charge.

Renewable Energy

A new distributed generation law was put into effect in September 2008, allowing regulated utilities to invest in small scale (less than 5 MW per site) distributed energy projects to increase overall energy efficiency and provide energy diversity by eliminating, displacing, or better managing energy deliveries from the centralized bulk power grid under regulatory oversight. PSNH continues to investigate small scale renewable options, but even with federal tax credit incentives, the cost to customers is high. PSNH is looking into alternative sources of funding to buy down the over market cost of the renewable projects.

The net energy metering incentive was significantly expanded with the passage of House Bill 1353 in June 2010. Rulemaking that commenced in August 2010 will result in revised program rules and utility tariffs that will implement the expansion. Under the old rules, customer-sited generating facilities powered by renewable sources were eligible for net energy metering provided the total peak generating capacity was less than 100 kilowatts. The revised program expands the eligibility to facilities between 100 and 1,000 kilowatts, provided the facility first began operating after July 1, 2010. The new program will also provide for a payment to customers for surplus energy delivered onto the PSNH distribution system. The payment rate will be based on PSNH's avoided cost. The revised rules also allow PSNH to file for annual recovery of the net effect this program has on default energy service and distribution revenues.

## A.2. Making Progress toward a Cleaner Generation Fleet

As required by state law, PSNH continues construction on the Clean Air Project at Merrimack Station in Bow, New Hampshire to install a wet flue gas desulphurization scrubber system to remove mercury and $SO_2$ emissions. PSNH expects construction to be approximately 75 percent complete by the end of 2010 and is on track for project completion by mid-2012.

The first compliance period for the New Hampshire Renewable Portfolio Standard began in 2008 and the Renewable Energy Fund (REF) received about $4.5 million in total from Class III and Class IV alternative compliance payments from all electricity providers in New Hampshire. A portion of the funds collected for Class III and Class IV compliance are being used to support a rebate program for small residential solar photovoltaic systems, but such programs by design do not provide the Renewable Energy Certificates needed to comply with the RPS law. PSNH's payment into the REF was approximately $2.5 million for the 2008 compliance year and just under $1 million for the 2009 compliance year. PSNH receives New Hampshire Class I RECs for output from the Lempster Wind project and the upgrade made at Smith Hydro Station. PSNH is also currently co-firing cocoa shells, a biomass product, in its Schiller Station, however under current New Hampshire RPS rules, co-firing is not eligible for RECs. At this point, PSNH is most deficient in Classes II, III, and IV and continues to work on finding the best cost compliance solutions for its customers.

PSNH also received approval in March 2010 from the Commission to offer a Renewable Energy Service rate. Under this new optional rate, a customer can elect to have PSNH cover 25%, 50%, or 100% of each month's usage with Renewable Energy Certificates representing the renewable attributes of power generated from certified renewable energy sources. The customer will pay a premium for the service offering.

## B. Energy Efficiency Potential

PSNH along with the other New Hampshire utilities participate in energy efficiency through the statewide CORE Programs funded by a portion of the Systems Benefits Charge. Through the analysis performed in this LCIRP, PSNH concluded that the CORE Programs offered today are cost-effective and provide technical and financial assistance to all classes of customers. These programs are having an appreciable impact on New Hampshire's energy use, and they provide the base upon which significantly expanded programs can achieve New Hampshire's full energy efficiency potential. In addition, PSNH developed an analysis on the potential for energy efficiency in PSNH's service territory using the GDS Associates study's Potentially Obtainable Scenario as the starting point for the analysis. Based on PSNH's analysis, achieving the Market Potential Scenario within PSNH's service territory will save 13,551 MWh for residential customers and 55,781 MWh for commercial and industrial customers on an annualized basis and increase efficiency program costs by about 140 percent by 2015.

## C. Meeting the Energy, Capacity, and REC Needs of PSNH's Default Energy Service Customers

During the LCIRP planning period (2011-2015), distribution customers' energy consumption is expected to grow about 0.4 percent per year. PSNH's distribution customers' system peak demand is expected to grow about 3.4 percent per year overall, but ranges from 0.5 percent growth per year in Berlin/Lancaster to 4.5 percent per year in the Portsmouth area. In addition, the New Hampshire Renewable Portfolio Standard requires a portion of customers' default energy service requirements to be supplied from renewable sources. However, these general peak load growth observations are not directly applicable to serving default energy service requirements because PSNH's default energy service requirements are influenced by migration, whereas distribution requirements are not. Since the last LCIRP filing migration has become a material factor in determining how PSNH serves its default energy service requirements.

In very general terms PSNH's variable energy costs are significantly driven by coal prices while overall New England energy prices are driven by natural gas prices. PSNH's generation capacity costs are the fixed costs of the company's generation fleet while capacity prices in New England are driven by the Forward Capacity Market. Since customers have competitive retail choice options, customers will be inclined to leave PSNH's default energy service rate when gas prices are low and capacity prices are low and will return when gas prices are high and capacity prices are high, relative to PSNH's fleet costs. Conditions favorable to migration for some customer classes developed for the first time since Competition Day in the second half of 2008 and have persisted. These conditions are discussed in greater detail throughout the LCIRP. Whether these conditions will continue throughout the planning period is unknown. To address this uncertainty, a range of migration levels are discussed in this plan. However, because migration has gone from an immaterial level and/or a seasonal concern to a significant sustained level, this plan focuses on the flexibility needed to dynamically address changing default energy service requirements.

PSNH has a fixed group of generation resources available to serve its default energy service customers' needs. As a result, to the extent PSNH can not meet its default energy service requirements the Company is dependent on the New England wholesale electricity market for energy and capacity, and will be required to either purchase Renewable Energy Certificates from qualified facilities or make Alternative Compliance Payments to the State of New Hampshire for any renewable resource deficiency. The increase in migration resulting from changes in market fundamentals for energy and capacity has resulted in changes to PSNH's supplemental purchase plans.

## C.1. Supplemental Energy Purchases

Fundamentally, the starting point for determining how much supplemental energy is needed to meet default energy service requirements is to compare the expected economic operation of resources owned or contracted to PSNH, including IPP purchases, to its forecasted default energy service needs. In PSNH's last plan, including its supplemental filings, the Company provided a narrative describing what it had previously done to meet its forecasted default energy service needs. In summary, the approach was to forecast need about a year ahead and to make a series of energy purchases to meet the forecasted need. The expectation was that a large portion of next year's need would be bought and reflected in that year's default energy service price. Thus, assuming the sales forecast and migration levels throughout the subsequent year were as forecast, this strategy produced dollar cost averaged energy prices, and minimizes potential over / under recoveries. As noted in those very same filings, while descriptive of what had been done, PSNH was not bound to this approach and discussed the need to maintain flexibility and recognized the possibility of modifying how it would fulfill future needs. Furthermore, PSNH advanced its energy purchases such that some future years were purchased earlier than had been done previously. In 2008 some purchases were made for periods as far out as 2011 in an effort to secure over time portions of needed supply so as to dollar-cost average procurements and minimize over and under recoveries during the delivery period. This advanced energy purchasing strategy, like the year-ahead energy purchasing strategy, was predicated on having a good estimate of migration and overall electricity sales levels.

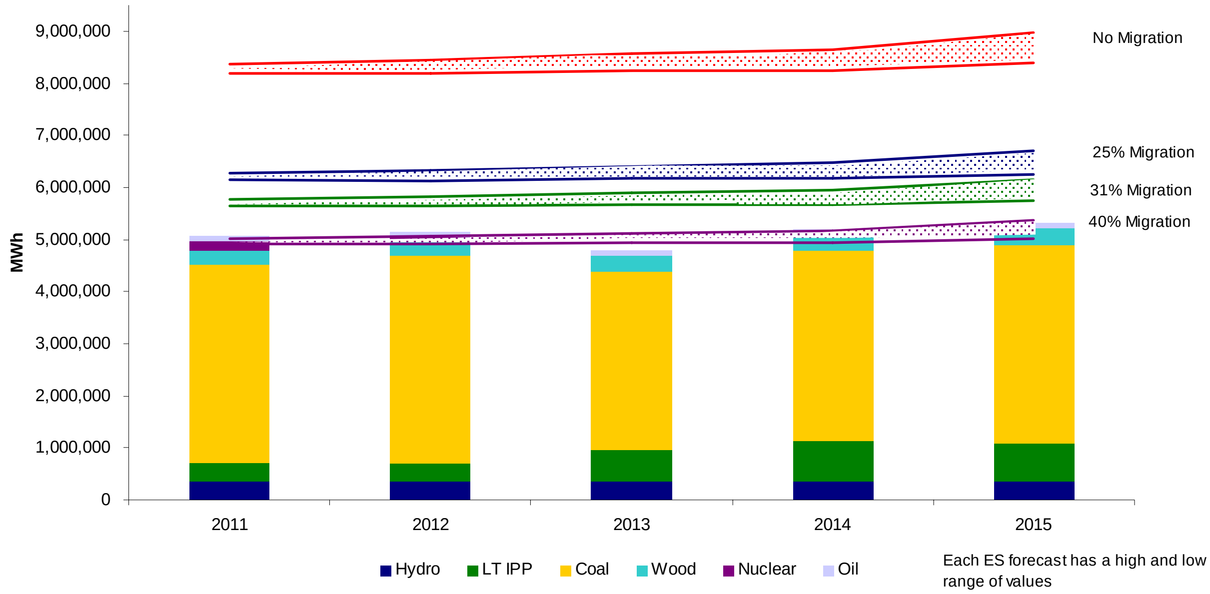
Part way through 2008, commodity prices collapsed and PSNH believes that competitive pricing moved toward and likely went below PSNH's then current default energy service rate for industrial customers by year's end. This price relationship continued into 2009 and competitive suppliers acquired customers throughout 2009 and into 2010, including expanding their reach to commercial customers. Concurrently, electric usage rapidly declined because of the recession. This invalidated the energy sales forecasts originally used for the calendar years 2009 and 2010.

As noted above, PSNH's default energy service rate provides significant benefits to customers when gas prices and/or capacity prices are high, resulting in higher energy prices in New England. Otherwise, PSNH's default energy service price may not be attractive to all customer groups. This paradigm may persist for the next few years while the country and state work their way out of the recession and demand for energy commodities gradually increases. Under these market conditions PSNH's continually evolving purchase strategy currently envisions looking at energy needs under a plausible high migration level when considering default energy service supplemental energy purchases prior to the start of the delivery period, and managing any remaining default energy service supplemental energy purchase needs through bilateral and ISO-New England administered energy markets during the delivery period.

In summary, the strongest motive behind PSNH's previous default energy service supplemental energy purchase strategy was to minimize over / under recoveries by locking in volumes and prices. However, the recession and resulting migration drastically impacted PSNH's prediction about the volume and price of energy to be purchased, and brought to bear factors in addition to over / under recoveries, thus highlighting the need to dynamically respond to changing circumstances.

Depending on migration levels PSNH will need to purchase varying amounts of energy annually in the open market over the planning period. Exhibit I-1 demonstrates PSNH's supplemental energy need under varying levels of migration levels under high and low load conditions. High and low load conditions are based on high and low economic conditions, prices, and C&LM efforts.

**Exhibit I-1: PSNH Supplemental Energy Need Under Varying Migration Levels**

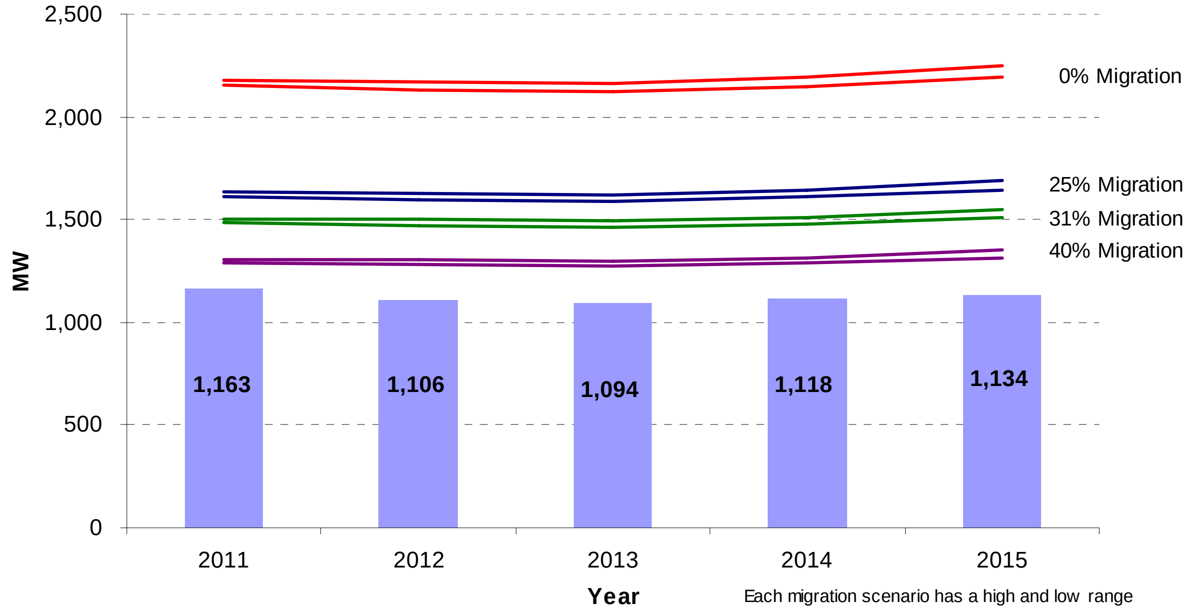



## C.2. Supplemental Capacity Purchases

Under current market rules, PSNH does not have to hold in its name the amount of capacity needed to serve default energy service customer requirements. PSNH is paid for the capacity it holds and pays for its share of ISO-New England capacity market costs resulting from serving default energy service customer load. Previously PSNH would adopt the planning approach of hedging the capacity shortfall to provide price certainty by locking in a fixed capacity price for a fixed level of capacity. As of the writing of this plan capacity prices are known through May 2014, however, with PSNH's current migration situation, the quantity is not known. Given this situation, PSNH has no incentive to hedge its short-term capacity deficiency, but instead will address any capacity shortfall by paying ISO-New England for PSNH's net requirement at known capacity market prices which will be reflected in the default energy service rate.

Depending on migration levels, PSNH will need to pay for varying amounts of capacity over and above its own resources. Exhibit I-2 shows the range of capacity amounts PSNH will need to pay for under the same range of migration levels under high and low load conditions as shown for energy purchases. High and low load conditions are based on high and low economic conditions and prices.

**Exhibit I-2: PSNH Supplemental Capacity Obligations Under Varying Migration Levels**

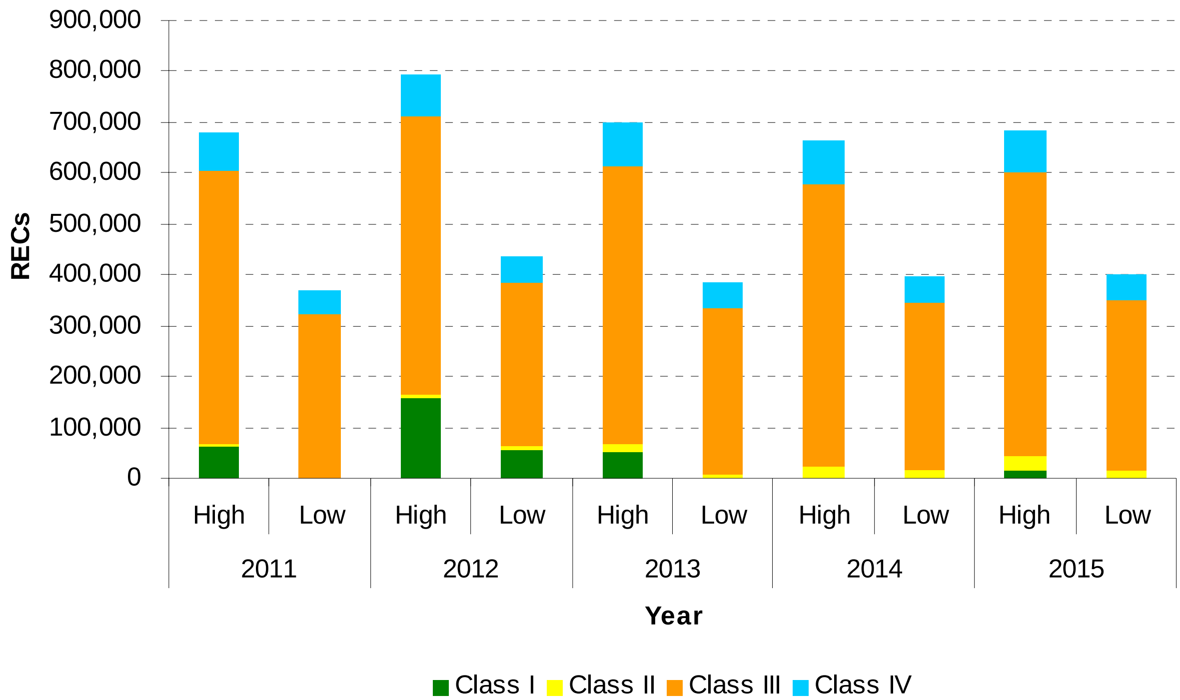



## C.3. Renewable Energy Certificate Purchases

Renewable Energy Certificates (RECs) that PSNH needs to comply with the New Hampshire Renewable Portfolio Standard (RPS) are procured through a variety of methods, including owned-resources (e.g., Smith hydro), long-term power purchase agreements (e.g., Lempster Wind), negotiated contracted with renewable resources, and via environmental resource aggregators and brokers. In addition, to the extent RECs are not available under reasonable terms and conditions, PSNH can comply with the RPS by making payments into the Renewable Energy Fund at the lowest Alternative Compliance Payment (ACP) price. Section X.C. provides more details on PSNH's procurement strategy.

PSNH's actions to meet the New Hampshire RPS requirements for its default energy service customers will also vary depending on migration levels. Exhibit I-3 shows the range of RECs PSNH will need to comply with RPS requirements under high load and low load scenarios. High and low load conditions are based on the base case sales forecast and C&LM efforts and vary based on high and low migration levels.

**Exhibit I-3: PSNH's Current Renewable Resource Need**




## D. Conclusion

PSNH will continue to pursue effective processes to manage its default energy service energy, capacity, and REC supplemental purchase needs as impacted by overall changes in distribution sales, including the effects of C&LM, and migration.

The events listed above highlight the changing environment in which PSNH operates and the challenges PSNH faces in planning due to the uncertainty that exists and the volatility of the underlying markets. PSNH continues to monitor external events and provide input to legislators, regulators, policymakers, and other stakeholders on shaping policies, regulations, and rules. PSNH utilizes its supply resources, energy efficiency, and demand resources to meet increasing customer demand and highlights PSNH's involvement as it relates to ISO-New England, state, and industry initiatives.

## E. Overview of LCIRP

A summary of the sections contained in the LCIRP filing are described below.

**Introduction and Nature of the Plan:** Provides an understanding of the environment in which PSNH operates and the role that PSNH plays in the current market.

**Electrical Energy Demand Forecast:** PSNH develops short-term and long-term energy and demand forecasts mainly for use in financial planning. This section describes the methodology and assumptions used to develop the delivered energy and peak demand forecasts and illustrates forecast scenarios based on high and low growth scenarios.

**Assessment of Demand-Side Programs:** PSNH is involved in conservation and load management (C&LM) efforts through the CORE Programs, a statewide energy efficiency program offered by each of New Hampshire's electric utilities. In addition to the CORE Programs, PSNH offers several additional demand-side management programs including the Peak Smart and HEATSMART. ISO-New England also offers demand-side programs at the wholesale level. These cost effective activities are available to all PSNH distribution customers regardless of the customer's retail electricity supplier.

**Assessment of Supply Options:** This section describes PSNH's existing generation supply resources including fossil fuel steam generating resources, fossil fuel combustion turbines, hydroelectric generating stations, biomass, long-term purchase power agreements with Independent Power Producers (IPP), and long-term rate orders. This section also discusses how PSNH meets its customers' energy requirements with a mix of owned and obligated resources and supplemental purchases.

**Assessment of Transmission Requirements:** ISO-New England is responsible for the coordination and planning of transmission in New England, including PSNH's transmission system.

**Provision for Diversity of Supply Sources:** PSNH's supply mix is diverse and includes coal, coal/oil, oil/natural gas, hydroelectric, biomass, Independent Power Producer contracts and rate orders and wholesale purchases. This supply diversity gives PSNH a flexible energy supply strategy.

**Integration of Demand-Side and Supply-Side Options:** Provides an analysis of a portfolio of supply side options in combination with demand side programs and identifies a combination of options that provides lower costs to customers compared to pure market purchases and is achievable given the constraints of the current environment.

**Assessment of Plan Integration and Impact on State Compliance with the Clean Air Act Amendments of 1990:** The federal Clean Air Act Amendments of 1990 established emissions goals for the electric power industry. PSNH has been proactively working to comply with these regulations using fuel switching and emissions allowance management strategies.

**Compliance with the New Hampshire Renewable Portfolio Standard:** The New Hampshire Legislature passed the Renewable Portfolio Standard requiring that a portion of PSNH's electricity supply come from renewable sources. This section describes the RPS requirements and PSNH's strategy for compliance.

**Compliance with the National Energy Policy Act of 1992:** The Energy Policy Act (EPAct) of 1992 added certain provisions to the Public Utility Regulatory Policies Act (PURPA) of 1978 standards which relate directly to integrated resource planning. This section describes PSNH's compliance with the EPAct in the areas of integrated resource planning and energy efficiency and demand-side management programs.

**Assessment of the Plan's Long-and Short- Term Environmental, Economic and Energy Price and Supply Impact on the State:** In addition to the Clean Air Act Amendments of 1990, there have been several federal and state environmental initiatives affecting PSNH's air emissions including sulfur dioxide ($SO_2$), nitrogen oxide (NOx), carbon dioxide ($CO_2$) and mercury (Hg). This section discusses the impact that current and potential federal and state regulations will have on PSNH and its customers.

**Newington Station Continuing Unit Operation Study:** Per Commission Order No. 25,061, PSNH is required to file a continuing unit operation study for Newington Station in its 2010 Least Cost Integrated Resource Plan filing. The study analyzes Newington Station's going forward costs and the benefits the Station provides to customers by continuing to be owned and operated as a regulated generation asset by PSNH.

# II. Introduction and Nature of Plan

This section introduces PSNH's Least Cost Integrated Resource Plan filing, describes the regulatory background behind the filing and the current environment in which PSNH operates.

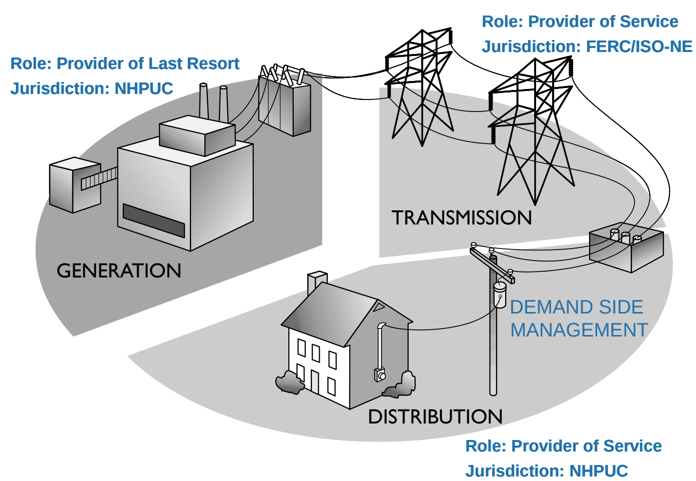
## A. Regulatory Compliance

This plan is filed with the Commission in accordance with requirements established by New Hampshire RSA 378:38. Its content is consistent with the Partial Settlement Agreements approved by Order No. 24,695 dated November 8, 2006 and Order No. 24,945 dated February 27, 2009, where applicable. In some instances, information was omitted as it was not relevant to the information presented in the 2010 LCIRP filing.

## B. Role in Delivering Energy to Customers

Exhibit II-1 illustrates the current operating environment for delivering energy in New Hampshire and indicates the role that PSNH plays in each part of the energy delivery process and the authoritative body that has jurisdiction over each function.

**Exhibit II-1: Energy Delivery Roles in New Hampshire**

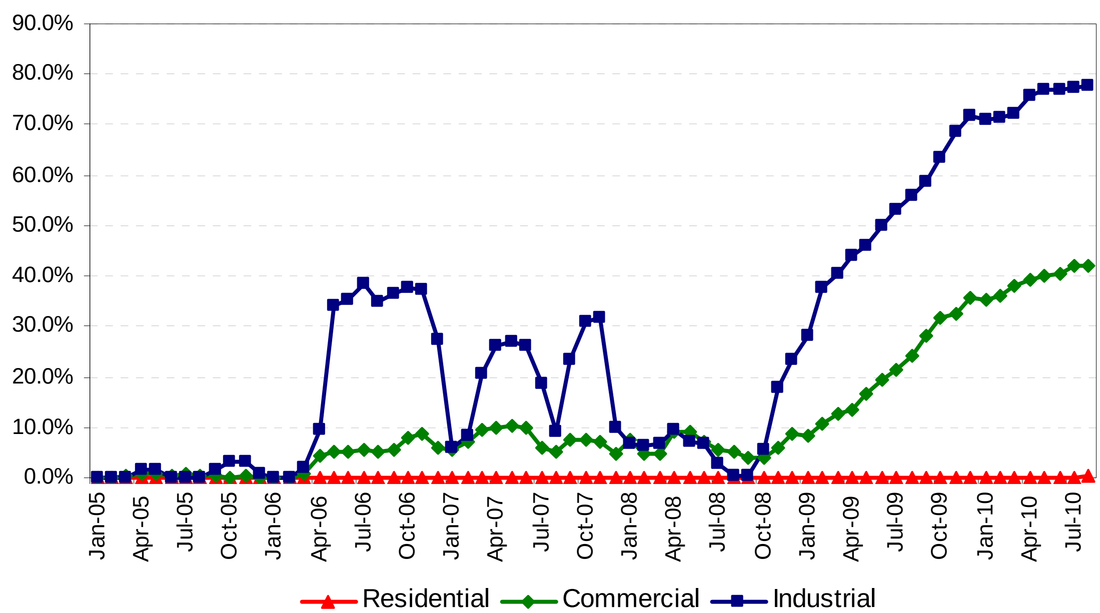



As a result of electric restructuring, PSNH's role in energy delivery is broken into several components – distribution, transmission, and generation. Under the distribution component, PSNH has responsibility to provide service to all of its distribution service customers, operate and maintain all poles and wires, perform services to connect new customers, plan, and build distribution plant for customers' peak demand requirements, and offer energy efficiency and demand side management opportunities to all of its distribution customers. Under the generation component, PSNH's role is to serve as the provider of last resort to those customers that do not choose to have their energy supplied by a competitive supplier. PSNH's objective in ownership of generation is to provide customers with reasonably priced default energy service, thereby offering a measure of price discipline in an otherwise unpredictable marketplace while also ensuring customers may freely choose a competitive energy supplier. As required under the law, PSNH uses the physical generating assets that it owns to serve its customers' load first and either purchases from the market any excess needed or sells to the market any excess supply that exists. PSNH, as a subsidiary of Northeast Utilities, provides Transmission service regulated by the Federal Energy Regulatory Commission and administered by ISO-New England.

## C. Competitive Environment

The competitive force of multiple suppliers vying to serve retail customers is the basis of the belief that competition will bring lower prices to retail customers in New Hampshire. PSNH continues to support customer choice in the competitive retail market. Over the past year, the amount of load served by third party suppliers has significantly increased, particularly in the industrial class, as shown in Exhibit II-3 below. The increased migration activity occurs when near-term market conditions enable retail suppliers to offer contract options that are competitive with PSNH's default energy service rate. Under current rules, migrated customers are free to return to PSNH's default service at any time. Customers choose the least cost option for them by comparing available rates for energy supply, including PSNH's default energy service rate.

**Exhibit II-3: Percent of Class Load Served by Third Party Suppliers, August 2010**




In addition to providing default energy supply to its customers, PSNH, as a regulated utility, implements energy efficiency programs in accordance with public policy requirements, as directed by the Commission. Competitive energy suppliers and other contractors may also provide energy efficiency programs to electric retail customers; however, to date, PSNH remains the principal supplier of such services in its service territory.

## D. Regional Energy Supply

At the time of the previous LCIRP filing in 2007, ISO-New England predicted that an additional 4,000 MW of generating capacity would be needed by 2016[1]. Due to the decline in economic activity throughout 2008 and into 2009, the more efficient use of electricity overall, and higher energy prices seen into mid-2008, New England actually saw a decrease in energy consumption in 2008 and 2009. As a result of market conditions and added generation, ISO-New England expects to have adequate resources in New England to meet customer peak demand through 2018, according to the 2009 Regional System Plan[2]. Work done by ISO-New England in preparation for the 2010 Regional System Plan shows this surplus extending through 2019[3]. While neither forecast predicts generation retirements, they also do not make any assumptions about ongoing C&LM efforts, or any new generation build-out driven by state RPS requirements.

## E. Planning Under Uncertainty

Since the previous LCIRP was filed, the planning environment in which PSNH operates has undergone significant changes. Environmental requirements and transmission constraints have moved to the forefront. More stringent environmental requirements could increase costs to customers. PSNH works to minimize any cost impact on customers resulting from these programs by efficiently operating its generation facilities and promoting energy efficiency programs. In addition, PSNH looks for lower cost alternatives to keep up with customer demand and regulatory requirements.

PSNH undertakes energy supply planning to provide customers who are not served by a competitive retail supplier with default energy service. The Commission has reviewed PSNH's generation planning and operation during annual stranded cost reconciliation and energy service dockets. Additionally, PSNH has demonstrated cost effective planning through the construction and operation of Northern Wood Power at Schiller Station, the runner upgrade at Smith Hydro, a renewable power purchase agreement with Lempster Wind, and REC purchase agreements with qualified facilities. These examples demonstrate PSNH's willingness to creatively prepare for the future energy supply needs of its customers, being simultaneously sensitive to the market realities of costs and environmental stewardship while complying with State energy policy and regulations. PSNH supported legislation to increase the amount of renewable energy produced in the state and continues to work to educate and prepare interested parties on the impact that these requirements will have on our state's economy.

---

[1] ISO-New England Presentation at the 31st Meeting of the Conference of New England Governors and Eastern Canadian Premiers, June 26, 2007 - http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2007/neg_ecp_6_26_07.pdf

[2] ISO-New England 2009 Regional System Plan, October 15, 2009 http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf

[3] ISO-New England 2010 Regional System Plan Working Group - http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2010/apr122010/future_icr_2014-19_apr_2010.pdf

Uncertainty persists with regard to potential investment in generation assets. PSNH, like other generation owners, operates in a changing world, where future events are uncertain, but may increase operating costs. Furthermore, while markets for natural gas are low, historically fuel markets have been volatile and natural gas prices may rebound in the future. In addition, coal prices have increased as world wide demand for this generation fuel source has increased, but such increases in coal prices may also decline in the future. These variables and changes require PSNH to remain flexible in the operation of its generation assets. PSNH remains flexible with its generation assets with the ability to burn natural gas at its Newington Station and is co-firing coal with a biomass fuel (cocoa bean shells) at its Schiller Station. Flexibility in supplemental power purchasing is also key as reduced demands and increased customer migration have reduced the amount of energy that PSNH needs to procure in the market.

The planning horizon for this integrated resource plan is five years. Due to the restrictions on expansion of large-scale generation ownership by PSNH, and the reduced loads the Company is experiencing, PSNH has no plans to build new generating capacity greater than 5 MW. However, under RSA 374-G, PSNH can invest in small-scale distributed generation sized at 5 MW or less per site. PSNH continues to investigate opportunities for cost-effective, renewable generation to meet our customers' RPS requirements.

# III. Electrical Energy Demand Forecast

This section describes the process used for forecasting electrical energy and demand for use in long-term financial planning, supplemental energy purchasing planning, and capital planning. The methodology, assumptions, and scenarios are discussed in the sections below.

## A. Overview

PSNH uses four types of forecasts for different business purposes as shown below in Exhibit III-1:

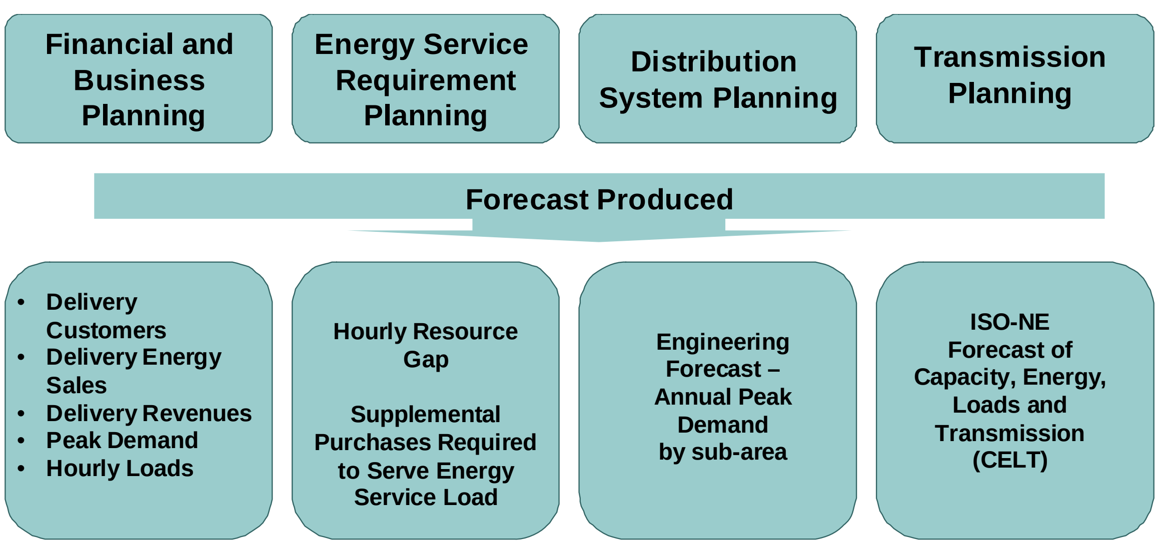
- Financial and Business Planning: Customer, Delivery Energy Sales by Class, Peak Demand, and Hourly Load forecasts.

- Energy Service Requirement Planning: Hourly load forecast, adjusted for customer migration or other forecast sensitivities, is used to develop the energy, capacity, and REC supplemental purchase requirement plan for PSNH's default energy service customers.

- Distribution System Planning: Engineering forecasts of the peak load by area for planning major capital projects affecting lines and substations.

- Transmission Planning: The ISO-New England has responsibility for regional transmission planning and develops its own independent forecast which is used by PSNH for its transmission planning. Refer to Section VI for the Transmission Plan filed herewith.

**Exhibit III-1: Forecast Types**



## B. Financial and Business Planning Forecasting

### B.1. Overview

PSNH produces two types of forecasts used for financial and business planning:

- Short-term (1-2 year) energy forecast used for budgeting purposes
- Long-term (5 year) energy and peak demand forecast used for business planning purposes

PSNH does not utilize long-term forecasts greater than five years for financial and business planning purposes because of uncertainty in the market and the inherent inaccuracy of forecasts. The long-term forecast is reviewed and revised at least annually to recognize the volatility of even a five year forecast. The forecasts presented in this section describe the market conditions that PSNH anticipates assuming the existing regulatory climate as of April 2010 (the date the forecast was prepared).

The following sections describe the forecast methodologies and discuss the base case, high case and low case forecast scenarios.

### B.2. Methodology

The following section provides a high level description of methodologies for the various types of forecasts that PSNH develops. For a more in depth discussion of the methodologies used, see Appendix A.

**Customer Count Forecast**

PSNH begins its forecast process with the development of a customer forecast. Econometric models are used to forecast customers by class, with customers as a function of an economic variable (households, non-manufacturing employment, or manufacturing employment).

**Delivery Energy Sales Forecast**

The next step in the forecasting process is the development of a Trend forecast and a Reference forecast for delivery energy sales. The Trend forecast is the starting point for the forecast development before any adjustments are made. The Reference forecast is equal to the Trend forecast adjusted for PSNH's Conservation & Load Management (C&LM), economic development programs, and projected net gains or losses resulting from large customer changes. These forecasts can also be described as "50/50" forecasts meaning that there is a 50 percent chance that the forecast will be exceeded. Both the Trend and the Reference forecasts assume normal weather conditions, are based on the total franchise area that PSNH serves, and represent all energy delivered to PSNH's retail customers. It is important to note what is included and excluded from the forecast.

The delivery energy sales forecast includes:

- Former CVEC customers beginning in 2004
- Customers of third party competitive suppliers
- Seabrook Station service

The delivery energy sales forecast does not include:

- Wholesale sales for resale and bulk power sales (Ashland, Wolfeboro, New Hampton, Unitil, New Hampshire Electric Co-operative and Central Maine Power customers served by PSNH's distribution system).
- Electrical losses

As a delivery company, changes in sales of default energy service due to industry restructuring are irrelevant and are therefore not factored into the financial and business planning forecast. However, for default energy service requirements planning, customer migration to third party suppliers is factored into the forecast used for that purpose, as discussed in section III.C.

**<u>Peak Demand Forecast</u>**

The next step in the forecasting process is the development of a Reference Peak Demand forecast. The highest hourly demand, which usually occurs during extremely hot or extremely cold weather, is referred to as the "peak demand." The purpose of the peak demand forecast is to develop the hourly energy forecast used for default energy service requirements planning.

The Peak Demand forecast uses sales by end use from the Trend Delivery Energy Sales forecast described in the previous section as an input to the process. Additional inputs include weather and historical peaks for each month. The peak demand is also adjusted to include electrical losses estimated at 5.8 percent.

**<u>Hourly Energy Forecast</u>**

The hourly energy forecast is used as an input into the default energy service requirements planning forecast. To develop the hourly energy forecast, the monthly delivery sales and monthly delivery peaks are combined into an econometric model and the shape of the line is adjusted so that the hourly loads add up to the monthly energy from the Reference Delivery Energy Sales forecast, which is divided by a delivery efficiency factor of 0.945 to convert into a pool transmission level, and the highest hour matches the monthly peaks from the Reference Peak Demand forecast.

The hourly loads for each year include company use, wholesale requirements, and electrical losses. This becomes the base forecast of system electrical energy requirements or output and is the amount of energy which must be supplied by generating plants or power purchases to serve the loads on the system. From this forecast, migration assumptions can be applied to develop a default energy service requirement forecast. For more detail on how the hourly forecast is used to make default energy service requirements decisions, see section III.C.

## B.3. Key Forecast Assumptions

Energy use forecasts for long-term planning purposes are based primarily on economic activity, price of electricity, projected efficiency improvements and saturation rates, weather, conservation and load management, and other key assumptions affecting energy usage. The sections below describe the major assumptions in greater detail.

### B.3.1. Economic and Demographic Assumptions

PSNH utilizes national and state economic and demographic forecast models developed by Moody's Economy.com in the delivery energy sales forecast models. These forecasts are developed by Moody's Economy.com for base, high growth, and low growth scenarios. A national forecast of inflation, the implicit price deflator for gross domestic product (PGDP), is used to measure income and prices on an inflation adjusted basis. All other economic and demographic variables used in the forecast are for the state of New Hampshire. Exhibit III-2 shows the economic and demographic assumptions used in PSNH's forecast and the Compound Annual Growth Rate (CAGR) from 2009 to 2015.

**Exhibit III-2: Economic Outlook, 2009-2015 (Base Case)**

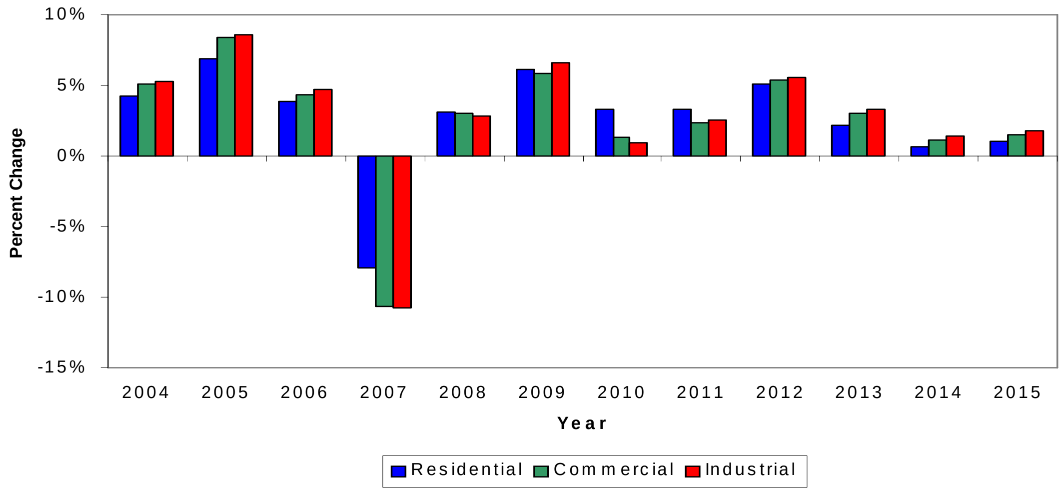
| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | CAGR |
|---|---|---|---|---|---|---|---|---|
| **New Hampshire** | | | | | | | | |
| Personal Income (Mil) | $56,801 | $57,540 | $59,790 | $63,635 | $68,134 | $72,199 | $75,567 | 4.9% |
| Real Personal Income ($2000 Mil) | $51,750 | $51,995 | $53,756 | $56,401 | $59,426 | $62,125 | $64,059 | 3.6% |
| Population (Thous.) | 1,326 | 1,334 | 1,343 | 1,353 | 1,362 | 1,371 | 1,379 | 0.7% |
| Housing Permits | 2,293 | 2,645 | 3,954 | 6,577 | 7,101 | 6,970 | 6,903 | 20.2% |
| Households (Thous.) | 508 | 509 | 512 | 517 | 521 | 525 | 528 | 0.7% |
| Non-Manufacturing Emp (Thous.) | 556.7 | 556.4 | 566.3 | 585.5 | 604.5 | 615.1 | 621.5 | 1.9% |
| Manufacturing Emp (Thous.) | 67.6 | 63.7 | 64.6 | 65.7 | 66.7 | 66.5 | 65.9 | -0.4% |
| Service Producing Emp (Thous.) | 533.1 | 534.4 | 544.3 | 562.1 | 579.6 | 589.6 | 595.9 | 1.9% |
| Non-Mfg Gross Product ($2000 Bil) | $43,305 | $44,660 | $46,538 | $49,230 | $51,103 | $52,475 | $53,850 | 3.7% |
| Mfg Gross Product ($2000 Bil) | $6,570 | $6,690 | $7,175 | $7,798 | $8,173 | $8,418 | $8,650 | 4.7% |
| Service Producing Gross State Product ($2000 Bil) | $41,933 | $43,303 | $45,193 | $47,770 | $49,538 | $50,888 | $52,265 | 3.7% |
| **United States** | | | | | | | | |
| Implicit Price Deflator for GDP | 1.10 | 1.11 | 1.11 | 1.13 | 1.15 | 1.16 | 1.18 | 1.2% |

Source: Moody's Economy.com, March 2010

### B.3.2. Retail Energy Price Assumptions

The forecast for each of the major retail classes contains a price of electricity variable. Annual historic prices of electricity used in the model are based on typical bills calculated from rate schedules by class of service. The forecast of electricity prices is based on current and projected rate levels as of April 2010. Prior to final analysis, all nominal electric prices are adjusted for inflation to provide real prices. Exhibit III-3 shows the real electric retail rate forecasts over the next five years for the residential, commercial, and industrial customer classes.

**Exhibit III-3: Real Retail Electricity Prices, based on typical bills (Base Case)**




Total delivery service is equal to the sum of the distribution, transmission, stranded cost recovery, system benefits, energy service, and consumption tax charges.

Additionally, high and low price scenarios were developed for use as inputs to the high and low forecast scenario analysis. The high price scenario was created by increasing the nominal energy service rate by 10 percent. Similarly, the low price scenario was constructed by decreasing the nominal energy service rate by 10 percent. The low price is used in the High Growth Case forecast since low prices generally indicate a stronger economy.

## B.3.3. Conservation Savings Assumptions

Estimates of projected C&LM reductions are developed based on the current level of funding through the System Benefits Charge. The Trend Delivery Energy Sales forecast is directly adjusted for these projected sales losses. Exhibit III-4 lists the estimated MWh saved by class each year on a cumulative basis as a result of conservation and load management programs. It is assumed that there will be continued funding for existing C&LM programs at the current funding level throughout the forecast period.

**Exhibit III-4: Conservation and Load Management**

| Cumulative C&LM Savings (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** |
| Residential | 0 | 13,798 | 27,593 | 41,390 | 55,188 | 68,986 |
| Commercial | 0 | 19,432 | 38,867 | 58,300 | 77,732 | 97,168 |
| Industrial | 0 | 6,478 | 12,956 | 19,433 | 25,911 | 32,389 |
| Streetlighting | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 39,708 | 79,416 | 119,123 | 158,831 | 198,543 |

## B.3.4. Other Key Assumptions

Economic Development

PSNH produces estimates of job gains or retentions as a direct result of economic development programs. An estimate of the additional MWh per class is developed using employment multipliers, an assumed average kWh per employee or customer, and an assumption on the percent of load due to economic development efforts already contained in the historical trend. Exhibit III-5 demonstrates the cumulative MWh effect of economic development programs. The Trend Delivery Energy Sales forecast is directly adjusted upward to account for the expected addition of load growth as a result of economic development programs.

**Exhibit III-5: Economic Development**

| Cumulative Economic Development Adders (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** |
| Residential | 96 | 276 | 456 | 636 | 813 | 997 |
| Commercial | 884 | 2,525 | 4,166 | 5,806 | 7,402 | 9,238 |
| Industrial | 628 | 1,772 | 2,916 | 4,060 | 5,156 | 6,347 |
| Streetlighting | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 1,608 | 4,573 | 7,538 | 10,502 | 13,370 | 16,581 |

Large Customer Changes

PSNH surveys its Account Executives to solicit field input on large accounts entering or leaving PSNH's service territory as well as anticipated changes in load usage of existing large accounts in the coming year. The Trend Delivery Energy Sales forecast is directly adjusted for the net result of sales as a result of large customer gains or losses.

Exhibit III-6 lists the estimated net MWh gained or lost by class each year on a cumulative basis due to changes in large customer usage. The forecast presented in this plan was adjusted to account for the opening of a large federal government facility in the State.

**Exhibit III-6: Large Customer Changes**

| Cumulative Large Customer Changes (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial | 9,504 | 18,996 | 18,996 | 18,996 | 18,996 | 18,996 |
| Industrial | 0 | 0 | 0 | 0 | 0 | 0 |
| Streetlighting | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 9,504 | 18,996 | 18,996 | 18,996 | 18,996 | 18,996 |

Self-Generation Losses

PSNH tracks customers that are planning to operate self-generation units for non-emergency purposes and therefore will not be taking full service from PSNH in the near future. Self-generation customers normally become Rate B customers since PSNH must deliver and possibly supply the customer with default energy service when the self-generation unit is unable to meet the load demands of the customer. Estimates of the amount of load served by self-generation are developed from discussions between PSNH's Account Executives and the customer. In the current base forecast there are no adjustments made for self-generation losses.

Generator Station Service

PSNH adjusts the Trend Delivery Energy Sales forecast to account for additional load provided to Seabrook Station during its refueling and maintenance outages. There is a specific adjustment for Seabrook Station load because of the large amount of energy delivered to the facility during a refueling and maintenance outage. PSNH does not adjust the Trend Delivery Energy Sales forecast for energy provided to other station service customers during generator outages due to their smaller size.

PSNH estimates the amount of additional load required for generation outages and adjusts the forecast to include additional sales expected as a result of increased station service requirements. Due to restrictions on public information related to specific generator outage schedules, the timing of planned outages at Seabrook are not known to the parties responsible for creating the PSNH forecast and therefore assumptions are made as to the timeframe and anticipated increase in load. Exhibit III-7 lists the additional load predicted as a result of Seabrook Station maintenance outages.

**Exhibit III-7: Station Service Additions**

| Annual Station Service Additions (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial | 0 | 11,326 | 11,326 | 0 | 11,326 | 11,326 |
| Industrial | 0 | 0 | 0 | 0 | 0 | 0 |
| Streetlighting | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 11,326 | 11,326 | 0 | 11,326 | 11,326 |

Weather

PSNH bases its forecasts on normal weather defined as the thirty-year average (1977-2006) of heating and cooling degree days for the Concord, New Hampshire weather station. Historical actual billed sales are weather normalized using heating and cooling degree days as reported for the Concord, New Hampshire weather station. The Trend and Reference Delivery Energy Sales forecasts assume normal weather conditions.

Electrical Loss Factors

The electrical loss factor, expressed as a percent of sales, used in reporting PSNH's system output is estimated at 5.8 percent for the distribution system. The electrical loss factors include distribution system losses but do not include transmission losses. Electrical loss factors are applied during the hourly load forecast development process.

## B.4. Energy and Demand Forecasts

Delivery energy and demand forecasts for 2010 through 2015 form the basis of resource planning in this integrated resource plan.

The Reference forecast is a 50/50 forecast, meaning that the forecast is adjusted to reflect normal weather conditions and is there is a 50 percent probability of the forecast being over or under the actual values. Additional forecast scenarios were developed to model high and low economic and price conditions and are demonstrated in this section. PSNH analyzed three growth scenarios to capture sensitivities to the forecast associated with uncertain economic and price conditions. The customer forecast and energy delivery forecasts were developed using these scenarios. The impact of extreme weather on the peak demand forecast was also analyzed resulting in extreme weather scenarios based on a hot or cool summer and a cold or warm winter. These forecast scenarios provide sensitivities to the forecast and demonstrate the range of potential outcomes rather than a single reference forecast. Economic and price conditions are modeled for energy and weather is modeled for peak because general economic and price conditions have more of an impact on energy sales than peak demand whereas weather has the most impact on the peak day. Higher or lower economic conditions can change the delivery energy sales forecast by ± 3 percent whereas higher or lower weather conditions can change peak demand by ± 12 percent. The forecast scenarios modeled for energy and peak demand include:

- The Reference or Base Case forecast, which assumes that the New Hampshire and United States economies grow consistently and smoothly into the future with no disruptions. For the peak demand forecast, this case assumes normal peak-producing weather conditions.

- The High Growth Case, which models good economic conditions and low energy prices and their impact on the customer and delivery energy sales forecasts.

- The Low Growth Case, which models weak economic conditions and high energy prices and their impact on the customer and delivery energy sales forecasts.

- The Extreme Weather Cases, which model extreme weather conditions (i.e., hot or cool summer peak day and cold or warm winter peak day) and their impact on the peak demand forecasts.

### B.4.1. Customer Forecast

Exhibit III-8 graphs the customer forecasts for the Base Case, High Growth Case, and Low Growth Case scenarios over the planning horizon. The Base Case forecast shows a compound annual growth rate (CAGR) of 0.7 percent, while the Low Growth Case shows a 0.6 percent annual growth rate and the High Growth Case shows a 0.8 percent annual growth rate. Higher or lower economic conditions can cause average annual growth to be ± 0.5 percent in any year. See Appendix B for the detailed data behind the forecast scenarios.

**Exhibit III-8: Customer Count Forecasts**

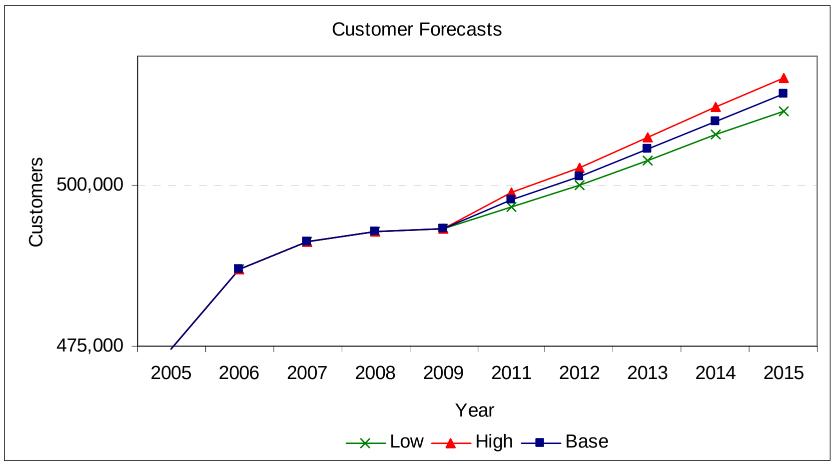



Exhibit III-9 below illustrates the Base Case forecast results by customer class. The 2005-2009 compound annual growth rate for total customers is 1.0 percent, compared to 0.7 percent over the 2010-2015 forecast period. The main reason behind the declining historical growth rates (2.6 percent in 2006 vs. 0.1 percent in 2009) is the recession that technically began in December 2007. A prolonged economic recovery will keep customer growth rates below their pre-recession values. Additionally, the introduction of the C2 billing system in 2008 altered how customers were counted. This had only a minor impact on the residential and commercial classes, and a more profound effect on the industrial and streetlighting classes.

**Exhibit III-9: Customer Count History and Forecast (Base Case)**

| Year | Res | % Chg | Com | % Chg | Ind | % Chg | St Lght | % Chg | Total Retail | % Chg |
|---|---|---|---|---|---|---|---|---|---|---|
| ***History*** | | | | | | | | | | |
| 2005 | 403,088 | | 68,232 | | 2,768 | | 563 | | 474,650 | |
| 2006 | 413,980 | 2.7% | 69,528 | 1.9% | 2,761 | -0.3% | 554 | -1.6% | 486,823 | 2.6% |
| 2007 | 417,420 | 0.8% | 70,341 | 1.2% | 2,770 | 0.4% | 564 | 1.8% | 491,095 | 0.9% |
| 2008 | 418,110 | 0.2% | 70,822 | 0.7% | 2,979 | 7.5% | 932 | 65.4% | 492,843 | 0.4% |
| 2009 | 417,670 | -0.1% | 70,984 | 0.2% | 3,134 | 5.2% | 1,399 | 50.0% | 493,187 | 0.1% |
| **Compound Annual Growth Rates (2005-2009)** | | | | | | | | | | |
| | 0.9% | | 1.0% | | 3.2% | | 25.6% | | 1.0% | |
| ***Forecast*** | | | | | | | | | | |
| 2010 | 419,571 | 0.5% | 71,736 | 1.1% | 3,095 | -1.3% | 1,456 | 4.0% | 495,857 | 0.5% |
| 2011 | 420,865 | 0.3% | 72,419 | 1.0% | 3,061 | -1.1% | 1,353 | -7.1% | 497,697 | 0.4% |
| 2012 | 423,420 | 0.6% | 73,457 | 1.4% | 3,050 | -0.4% | 1,358 | 0.4% | 501,285 | 0.7% |
| 2013 | 426,397 | 0.7% | 74,842 | 1.9% | 3,046 | -0.2% | 1,365 | 0.5% | 505,649 | 0.9% |
| 2014 | 429,283 | 0.7% | 76,282 | 1.9% | 3,042 | -0.1% | 1,371 | 0.5% | 509,978 | 0.9% |
| 2015 | 432,037 | 0.6% | 77,614 | 1.7% | 3,039 | -0.1% | 1,377 | 0.4% | 514,067 | 0.8% |
| **Compound Annual Growth Rates (2009-2015)** | | | | | | | | | | |
| | 0.6% | | 1.5% | | -0.5% | | -0.3% | | 0.7% | |

## B.4.2. Delivery Energy Sales Forecast

Exhibit III-10 shows the Reference Delivery Energy Sales forecasts for the Base Case, High Growth Case, and Low Growth Case scenarios over the planning horizon. The Base Case has an average annual growth rate of 0.4 percent over the planning horizon while the Low Growth Case has an average annual growth rate of -0.1 percent and the High Growth Case has an average annual growth rate of 0.8 percent. Therefore, based on these specific scenarios, there is approximately a 0.4 percent band around the Base Case forecast as a result of economic and price variability. See Appendix B for the detailed data behind the forecast scenarios.

**Exhibit III-10: Reference Delivery Energy Sales Forecasts**

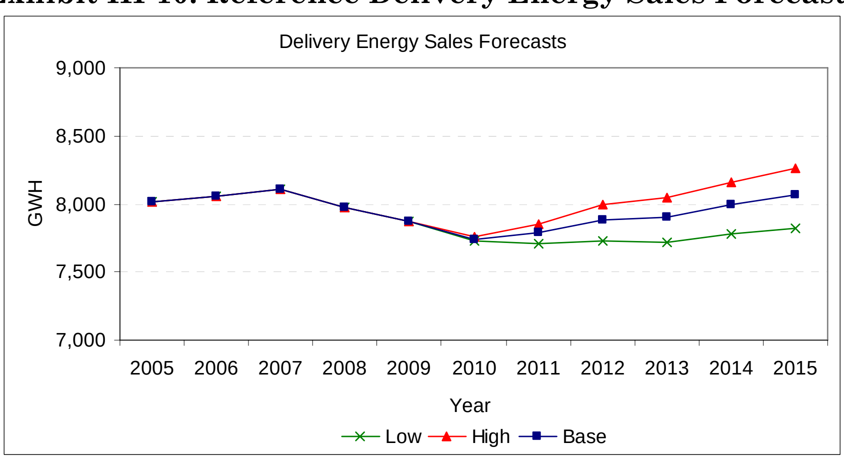



Exhibit III-11 below illustrates the Base Case forecast results by customer class, adjusted for PSNH's forecasted C&LM, economic development programs, and large customer changes. It does not include reductions due to ISO-New England's load response program, which is primarily focused on demand and not energy. The Base Case forecast assumes normal weather based on a thirty-year average (1977-2006) of heating and cooling degree days, a base case economic forecast, and continued funding of C&LM and economic development programs.

The 2005-2009 compound annual growth rate for total delivery energy sales is -0.5 percent on a weather-normalized basis. The 2009-2015 compound annual growth rate for total delivery energy sales is 0.4 percent on a weather-normalized basis. Without PSNH's C&LM programs, the forecasted growth rate would be 0.8 percent. In the forecast period, residential and commercial sales are expected to grow slightly more slowly than they have on average historically while industrial sales are expected to stabilize. During the recent historical period, oil and automotive gasoline prices reached record levels and housing values and financial markets collapsed, leading the U.S. into the deepest recession since the Great Depression. A slow economic recovery will result in subdued energy delivery sales in the forecast period.

**Exhibit III-11: Annual Reference Delivery Energy Sales (Base Case)**

| **Annual Reference Delivery Energy Sales (GWH)** | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Res Sales** | **% Chg** | **Com Sales** | **% Chg** | **Ind Sales** | **% Chg** | **St Light Sales** | **% Chg** | **Total Retail Sales** | **% Chg** |
| ***History (Weather Normalized)*** | | | | | | | | | | |
| 2005 | 3,102 | | 3,296 | | 1,592 | | 24 | | 8,014 | |
| 2006 | 3,118 | 0.5% | 3,341 | 1.4% | 1,574 | -1.1% | 23 | -5.4% | 8,057 | 0.5% |
| 2007 | 3,164 | 1.5% | 3,394 | 1.6% | 1,524 | -3.2% | 24 | 4.9% | 8,106 | 0.6% |
| 2008 | 3,132 | -1.0% | 3,380 | -0.4% | 1,442 | -5.4% | 25 | 2.2% | 7,978 | -1.6% |
| 2009 | 3,150 | 0.6% | 3,357 | -0.7% | 1,339 | -7.1% | 24 | -3.2% | 7,870 | -1.4% |
| **Compound Annual Growth Rates (2005-2009)** | | | | | | | | | | |
| | 0.4% | | 0.5% | | -4.2% | | -0.5% | | -0.5% | |
| ***Forecast*** | | | | | | | | | | |
| 2010 | 3,140 | -0.3% | 3,286 | -2.1% | 1,293 | -3.4% | 24 | 1.9% | 7,743 | -1.6% |
| 2011 | 3,156 | 0.5% | 3,316 | 0.9% | 1,291 | -0.2% | 25 | 0.5% | 7,788 | 0.6% |
| 2012 | 3,205 | 1.5% | 3,348 | 1.0% | 1,300 | 0.7% | 25 | 0.3% | 7,877 | 1.1% |
| 2013 | 3,242 | 1.1% | 3,352 | 0.1% | 1,285 | -1.2% | 25 | 0.3% | 7,903 | 0.3% |
| 2014 | 3,298 | 1.7% | 3,408 | 1.7% | 1,264 | -1.6% | 25 | 0.3% | 7,995 | 1.2% |
| 2015 | 3,337 | 1.2% | 3,453 | 1.3% | 1,250 | -1.1% | 25 | 0.3% | 8,065 | 0.9% |
| **Compound Annual Growth Rates (2009-2015)** | | | | | | | | | | |
| | 1.0% | | 0.5% | | -1.1% | | 0.6% | | 0.4% | |

Exhibit III-12 shows the adjustments made to the Trend forecast to arrive at the Reference forecast.

**Exhibit III-12: Annual Delivery Energy Sales Forecast Buildup, 2010-2015**

| Annual Delivery Energy Sales Forecast Buildup (GWH) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Trend | C&LM | Economic Development | Large C&I | Station Service | Company Use | Reference |
| 2010 | 7,732 | 7,732 | 7,734 | 7,741 | 7,732 | 7,732 | 7,743 |
| 2011 | 7,793 | 7,753 | 7,797 | 7,812 | 7,804 | 7,793 | 7,788 |
| 2012 | 7,919 | 7,839 | 7,926 | 7,938 | 7,930 | 7,919 | 7,877 |
| 2013 | 7,993 | 7,874 | 8,003 | 8,012 | 7,993 | 7,993 | 7,903 |
| 2014 | 8,111 | 7,952 | 8,124 | 8,130 | 8,122 | 8,111 | 7,995 |
| 2015 | 8,216 | 8,018 | 8,233 | 8,235 | 8,228 | 8,216 | 8,065 |

## B.4.3. Peak Demand Forecast

Exhibit III-13 shows the Peak Demand actual history and weather normalized forecasts for the Base Case and Extreme Weather Case scenarios over the planning horizon. See Appendix B for the detailed data for the Weather Scenarios.

For the summer peaks, the Base Case has a compound annual normalized growth rate of 0.7 percent over the planning horizon while the Extreme Cool Case has a compound annual growth rate of -0.5 percent and the Extreme Hot Case has a growth rate of 2.5 percent.

For the winter peaks, the Base Case has a compound annual normalized growth rate of -0.2 percent over the planning horizon while the Extreme Cold Case has a compound annual growth rate of 0.9 percent and the Extreme Warm Case has a growth rate of -1.9 percent.

These weather scenarios show that the variability of peak demand due to extreme weather conditions in the summer is up to about 11 percent. This results in about 194 MW of additional load in the summer due to extreme weather conditions.

**Exhibit III-13: Peak Demand Forecasts (Actual 2005-2009 and Forecast 2010-2015)**

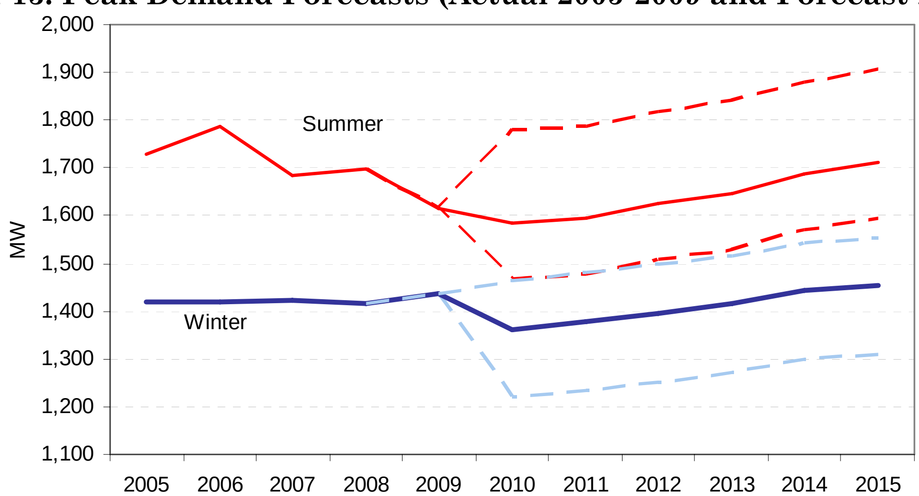


Exhibit III-14 below provides historic output and summer and winter peaks, normalized for weather. The 2005-2009 compound annual growth rate for peak demand is -0.6 percent in the summer and 0.9 percent in the winter on a weather-normalized basis. The 2009-2015 compound annual growth rate for peak demand is 0.7 percent in the summer and -0.2 percent in the winter on a weather-normalized basis. This table demonstrates that energy and peak load don't necessarily follow the same growth path. Weather and air conditioner use are the main drivers for growth in peak demands during the summer.

**Exhibit III-14: Annual Output and Peak Load, 2005-2015 (Base Case)**

| | Output (GWh) | % Chg | Summer (MW) | % Chg | Winter (MW) | % Chg |
|---|---|---|---|---|---|---|
| ***History (Not Weather Normalized)*** | | | | | | |
| 2005 | 8,655 | | 1,729 | | 1,419 | |
| 2006 | 8,489 | -1.9% | 1,786 | 3.3% | 1,418 | -2.7% |
| 2007 | 8,595 | 1.2% | 1,684 | -5.7% | 1,424 | -0.1% |
| 2008 | 8,408 | -2.2% | 1,698 | 0.8% | 1,417 | -0.5% |
| 2009 | 8,138 | -3.2% | 1,617 | -4.8% | 1,436 | 1.3% |
| **Compound Annual Growth Rate (2005-2009)** | | | | | | |
| | -1.5% | | -1.7% | | 0.3% | |
| ***History (Weather Normalized)*** | | | | | | |
| 2005 | 8,529 | | 1,670 | | 1,419 | |
| 2006 | 8,511 | -0.2% | 1,650 | -1.2% | 1,442 | 1.6% |
| 2007 | 8,569 | 0.7% | 1,662 | 0.8% | 1,388 | -3.7% |
| 2008 | 8,460 | -1.3% | 1,619 | -2.6% | 1,453 | 4.7% |
| 2009 | 8,258 | -2.4% | 1,619 | 1.2% | 1,471 | 1.2% |
| **Compound Annual Growth Rate (2005-2009)** | | | | | | |
| | -0.8% | | -0.6% | | 0.9% | |
| ***Forecast*** | | | | | | |
| 2010 | 8,194 | -2.5% | 1,585 | -6.6% | 1,362 | -5.1% |
| 2011 | 8,241 | 0.6% | 1.594 | 0.6% | 1,379 | 1.3% |
| 2012 | 8,336 | 1.1% | 1,626 | 2.0% | 1,396 | 1.2% |
| 2013 | 8,363 | 0.3% | 1,648 | 1.3% | 1,416 | 1.4% |
| 2014 | 8,461 | 1.2% | 1,686 | 2.3% | 1,442 | 1.8% |
| 2015 | 8,534 | 0.9% | 1,712 | 1.5% | 1,453 | 0.8% |
| **Compound Annual Growth Rate (2009-2015)** | | | | | | |
| | 0.8% | | 1.0% | | 0.2% | |
| **Normalized Compound Annual Growth Rate (2009-2015)** | | | | | | |
| | 0.5% | | 0.7% | | -0.2% | |

## B.4.4. Delivery Hourly Load Forecast

The Delivery Hourly Load forecast combines the Delivery Energy Sales forecast and the Peak Demand forecast to produce hourly values for use as a base forecast for Energy Service Requirement planning. In addition to the Base Case, the High Growth Case and Low Growth Case for Delivery Energy Sales and the Extreme Weather Cases for Peak Demand are provided to show the sensitivities to the forecast. A delivery sales hourly load forecast is developed as a final step in the financial and business planning forecasting process and is the base forecast used in the Energy Service Requirement forecasting process.

## C. Energy Service Requirement Forecasting

### C.1. Overview

The Energy Service Requirement forecast is used to determine the resource gap and required purchases needed to fill the resource gap. The Energy Service Requirement forecast is further refined throughout the year as more accurate planning information becomes available. This refined forecast ultimately is filed with the Commission during the Energy Service rate setting proceeding.

### C.2. Methodology and Assumptions

PSNH's Energy Service Requirement forecast incorporates customer migration, forecast sensitivities, planned generation outages, forced outages, forecasted dispatch patterns for the fossil units, and assumptions for hydroelectric and IPP production. These assumptions are discussed in further detail below.

#### C.2.1. Customer Migration and Forecast Sensitivity

PSNH is required to provide default energy service to all customers who do not select a competitive supply option. Current rules permit customers to move without limitation between competitive supply and PSNH's default energy service as often as every billing cycle. The base Delivery Hourly Load forecast is a forecast of the amount of energy PSNH expects to deliver to customers. Consequently, there is no assumed customer migration to competitive retail supply. Therefore, in order to develop the Energy Service Requirement forecast, the Delivery Hourly Load forecast must be adjusted to account for customer migration. In prior default Energy Service rate setting, PSNH has assumed a quantity of migration consistent with recent history (see Docket DE 09-180). Additionally, the sensitivities resulting from the high and low growth and extreme weather forecast scenario analyses have been taken into account when making adjustments to the Energy Service Requirement forecast.

For purposes of this LCIRP, PSNH developed a range of customer migration scenarios that drive the Energy Service Requirement forecast. The scenarios developed assume levels of migration by class. Exhibit III-15 describes the migration assumptions.

**Exhibit III-15: Migration Scenario Assumptions by Class**

| | Percent of Class Load Served by Third Party Supplier | | | |
|---|---|---|---|---|
| **Migration Level** | **Residential** | **Commercial** | **Industrial** | **Streetlighting** |
| **40%** | 0.2% | 53.9% | 99.3% | 43.5% |
| **31%** | 0.2% | 41.7% | 77.0% | 33.7% |
| **25%** | 0.1% | 33.7% | 62.1% | 27.2% |
| **0%** | 0.0% | 0.0% | 0.0% | 0.0% |

### C.2.2. Planned Generation Outages

Planned generation outages are based on the latest available maintenance schedule.

### C.2.3. Forced Outages

Between planned maintenance periods, a unique forced outage factor is applied to the full capability of each Schiller and Merrimack unit. This factor is based on historical performance, as modified to account for any anticipated, atypical operating conditions. Newington Station is assumed to be capable of its full claimed capacity between maintenance outages. Forced outages at the hydroelectric facilities are generically addressed by forecasting operation at the 20-year historical monthly average.

### C.2.4. Forecasted Dispatch Patterns for the Fossil Units

Fossil unit dispatch pattern assumptions are based on economic and operational considerations. For each major fossil unit (Schiller, Merrimack, and Newington), the anticipated per unit fuel expense (i.e., $/ton of delivered coal and wood, $/bbl of delivered oil, or $/MMBtu of delivered gas), plus variable O&M and emission adders, is converted into a $/MWh equivalent. This "dispatch price" is compared with the anticipated market price for power to determine the periods when the units will be economically dispatched. In general, the coal-fired and wood-fired units (Merrimack and Schiller) are economic in all periods and, thus, are assumed to operate as baseload resources outside of planned maintenance periods. Newington is generally dispatched in the more expensive months (e.g., December, January, July, and August) and is assumed to be in reserve for use in the remaining months. The combustion turbines are assumed to be in reserve to respond to short duration price spikes that exceed the average fuel and variable O&M expense of the units.

### C.2.5. Hydroelectric and IPP Production

Hydroelectric production is assumed to be equal to the 20-year historical average. IPP production is based on long-term historical averages.

## C.3. Energy Service Requirement Forecast and Planning

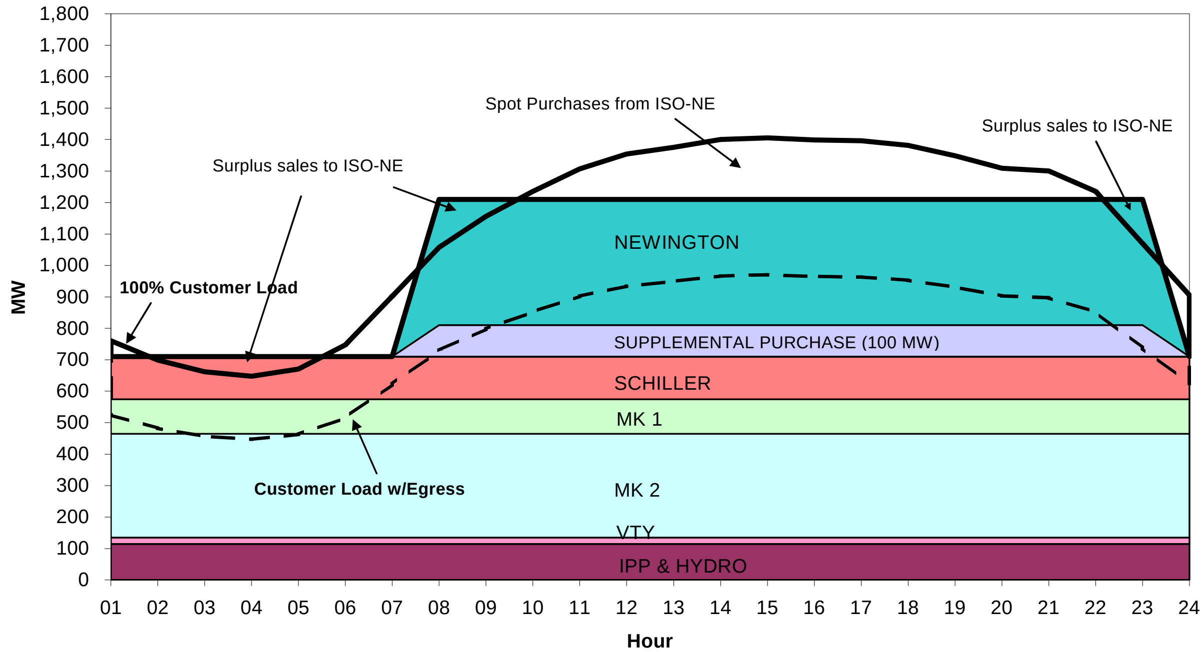
The hourly load forecast is converted into an energy service requirement forecast that varies hourly according to the default energy service load and supply resource balance. The purchase requirement changes hourly and can range from zero to a significant portion of total requirements, depending on the availability of PSNH's resources, the level of demand, the migration of customers to competitive energy service options, and the relative economics of PSNH's generation versus purchase alternatives. The hourly quantities are converted into monthly averages by time-of-use (e.g., on-peak and off-peak periods). In this manner, PSNH identifies a targeted set of block purchases that, on a volumetric basis, serves a quantity of load approximately equal to the sum of the hourly purchase requirement identified in the planning forecast. The volumetric approach converts a quantity that varies hourly into an average volume that can be procured via standardized bilateral contracts. PSNH's supplemental purchase procurement strategy is discussed further in Section V.

Long-term energy supply planning is further refined and/or supplemented by monthly, weekly, and daily planning. Prior to the start of a given month, PSNH reviews current load forecasts that include any customer migration to competitive supply. Also, any known changes to planned generation maintenance schedules are reviewed. Given the particular flexibility and fuel diversity of PSNH's Newington Station, the economics of this unit are closely monitored to ensure that the unit is operated in a manner that optimizes the fuel usage and incorporates operational considerations such as emission control, minimum down times, minimum run times, ramp rates, etc. For example, if replacement power contracts can be executed at prices that are less than the dispatch price of Newington, it may be possible to place the unit on economic reserve. A similar type of review is conducted prior to the start of each week and may be further refined during the week.

PSNH's supplemental purchases to support the default Energy Service requirement are heavily influenced by the economics of Newington. When Newington's fuel expense is lower than the cost of purchasing power, the unit is dispatched and PSNH's supplemental need is significantly reduced. Assuming minimal migration, during on-peak hours, when PSNH's baseload and intermediate resources (including Newington) are dispatched, PSNH requires supplemental purchases that range from zero (during low load months) to approximately 400 MW (during high load months). Typically, Newington is not economic for dispatch during the off-peak hours (weekends, holidays, and weekdays during hours 1-7 and 24). Again assuming minimal migration, the resulting off-peak purchase requirement will range from zero to 400 MW. Forced and planned outages increase the need for supplemental purchases.

On a daily basis, PSNH forecasts the hourly load and supply resource distribution for the following day. This process incorporates updated information on weather and load patterns, fossil unit availability, Newington status, hydroelectric and IPP production forecasts and existing power purchases. The daily forecast determines the anticipated level of energy obligation that is not being served by PSNH's generating units and purchases (i.e., the ISO-New England spot purchase exposure). PSNH reviews this exposure and, if required, executes additional bilateral purchases (PSNH's daily spot market risk policy is to limit daily spot exposure to 15 percent of the on-peak energy requirement and 30 percent of the off-peak requirement). Typically, and by necessity, a small portion of PSNH's energy obligation is procured via the ISO-New England spot market. Also, each day normally includes a number of hours in which PSNH has surplus supply that is sold into the ISO-New England spot market. To illustrate this interaction with the ISO-New England spot market, Exhibit III-16 depicts PSNH's typical summer weekday energy position.

**Exhibit III-16: PSNH Typical Summer Weekday Energy Position**




As migration increases the load line shifts down, the amount of supplemental energy needed is reduced and the amount of potential surplus generation that is sold into the wholesale market increases. Wholesale market revenues associated with surplus generation are credited to default Energy Service customers. Since late-2008 migration has been increasing and is affecting how PSNH approaches long-term supplemental energy purchases to meet default energy service customer needs. These changes are discussed in Section V.

## D. Distribution System Planning Engineering Forecasting

### D.1. Overview

Planning for capital expansion of the distribution system is driven by the System Planning Department engineering forecast for peak demand. As the first step of the annual planning forecast process, PSNH's distribution System Planning Department provides an engineering forecast for the overall system and by geographic area. The current methodology for forecasting is based on historical data analysis, probability forecast, and engineering judgment for PSNH's entire system and each geographic area. The engineering forecast is reviewed annually and updated based on actual peak demand data for each geographic area and overall PSNH simultaneous peak.

Ultimately, the distribution system must be capable of serving the peak load experienced; therefore, an accurate forecast methodology which results in construction recommendations at the 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. Invariably, any model which attempts to forecast the future will yield an estimate that is different 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 oversight and procedures. Distribution system only projects inherently require shorter planning and construction periods and therefore allow opportunities to modify plans and adjust in-service dates as circumstances change.

## D.2. Methodology

The first step in the engineering forecast development is identifying actual historical peak demands. PSNH records overall system peak load based on the highest single hour of demand as measured simultaneously at many points across PSNH's system and accumulated at the Electric System Control Center (ESCC). The overall PSNH system peak is used to calculate the compounded growth rate for the entire PSNH distribution system. PSNH also records each geographic area peak which is used to calculate a load forecast based for each area. The geographic area forecast is used in PSNH's computer model to identify capacity addition needs. Each area represents localized distribution systems and allows 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.

Exhibit III-17 shows the historical and engineering forecast percent growth rate for the overall PSNH system and each geographic area. It is based on ten years of historical peak data and the compounded growth rates for the years 1999-2009. 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.

**Exhibit III-17: PSNH Summer Peak Load Forecast by Area**

| | | Compound Annual Growth Rate (%) | |
|---|---|---|---|
| Area | 2009 Summer Peak (MW) | Historical (1999-2009) | Forecast (2010-2015) |
| Lakes Region | 165.6 | 4.24 | 3.0 |
| Derry | 122 | 5.36 | 4.0 |
| Dover/Rochester | 156.8 | 4.26 | 3.2 |
| Manchester | 343.7 | 2.98 | 3.75 |
| Sunapee | 39.0 | 1.71 | 2.7 |
| Berlin/Lancaster | 47.0 | -1.08 | 0.5 |
| Portsmouth | 236.6 | 5.42 | 4.5 |
| Nashua | 374.8 | 2.64 | 2.5 |
| Western | 162.7 | 2.83 | 3.0 |
| Conway/Ossipee | 68.7 | 3.79 | 3.5 |
| Seacoast | 147.4 | 4.83 | 4.0* |
| Concord | 122.9 | 3.63 | 3.5* |
| **PSNH System **** | **1734.8** | **4.21** | **3.4** |

*Unitil provides load data for these areas utilizing its forecast methodology.
** PSNH System data includes NHEC and municipal load fed at the distribution level.

## D.3. Planning Use of the Engineering Forecast

System planning is performed for PSNH'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. The study grows the system load annually according to the engineering forecast report. System overloads and operating constraints are identified per year based on PSNH's ED-3002 Distribution System Planning and Design Criteria Guidelines. These guidelines provide long-term solutions incorporating issues such as good engineering design, reliability, power quality, and operating strategies. These guidelines provide the basis for least cost planning of the distribution system.

The annual system study is a 10 year forecast analysis which identifies capacity needs for the PSNH distribution system based on PSNH procedure ED-3002. The first five years of the ten-year report are used for short term planning and budgeting. The second five years of the report are used to identify longer term loading and system issues. The long term system issues are analyzed by System Planning to determine what type of overall strategy for an area is best. In some cases doing 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 problems identified; however, the cost-benefit analysis always carries the most weight.

The first five years of the report are given more weight in identifying the least cost options for construction as well as addressing area-wide issues that may arise in the latter years of the ten-year study period. Additionally, the first five years of the ten-year study period clearly identify major substation and line additions and their needed in-service dates.

## D.4. Planning by Area

The construction requirements for the electrical system are based on each area's load growth and the area engineering forecast. Some areas experience peak demand growth rates 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 distribution capacity is required where the load growth is located, the planning process generally results in total system capital investment requirements that exceed what would be required if planning was simply performed based on PSNH's total system load growth. The summer peak demand history by area is shown in Appendix C.

## D.5. PSNH Actual Peak Load Curves

Since 1997, PSNH has been a summer peaking utility as depicted on Exhibit III-18. This is primarily because of the reduction in the use of electric heat and increase in the use of air conditioning by PSNH's customers. An increase in load related to residential air conditioning has been a significant factor during the past several years, partly because residential load is generally more temperature sensitive than industrial load. PSNH's historical compounded summer actual peak demand growth rate is 4.21 percent while the winter growth rate is 1.72 percent.

**Exhibit III-18: PSNH Peak Load Curve by Season**

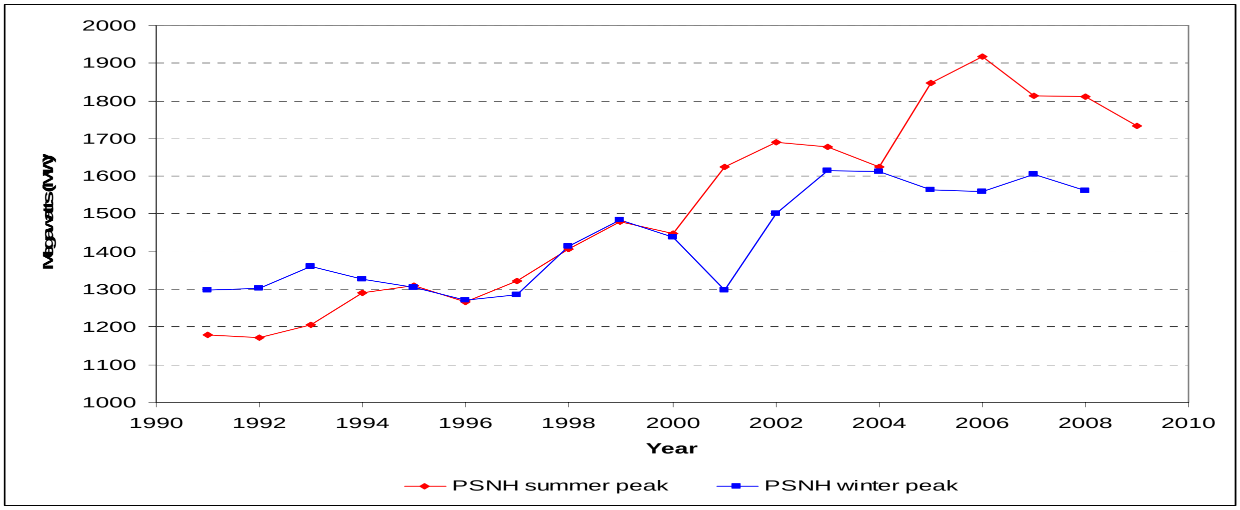
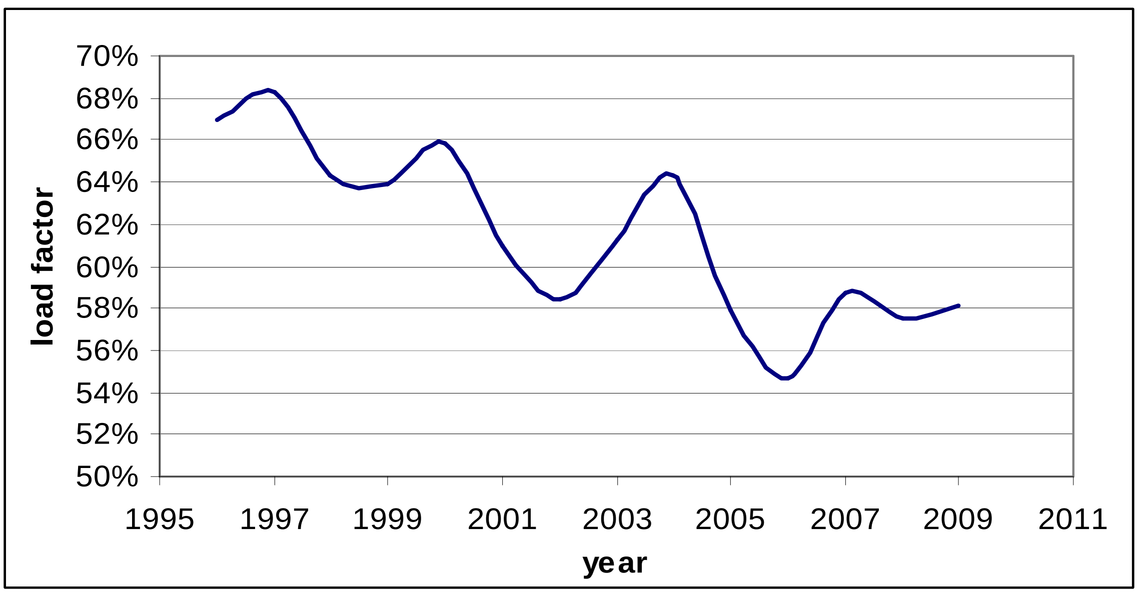



Exhibit III-19 shows PSNH's load factor from 1996 through 2009. There has been a steady decline in load factor since 1996 with some stability from 2006 to the present.

**Exhibit III-19: PSNH Load factor Curve, 1996-2009**




The 10 percent drop in load factor[4] from 2003 to 2006 is attributed to low cost window air conditioning units coupled with elevated summer temperatures. The added load created high peak demands but relatively low operating times for the air conditioning units. Conversely, from 2006 to 2009 a slower economy coupled with relatively moderate summer temperatures equated to level energy delivered and lower peak demands. Cooler weather reduces air conditioning consumption during peak periods, which results in a lower demand

[4] The calculation for load factor is Load Factor = kWh / (kW Peak x 8,760 Hours per Year)

during peak power consumption days. The lower LF requires the installation of additional peak capacity, which will be used for fewer hours on an annual basis.

Some peak demand-reducing methods such as the Peak Smart program have been in place and used successfully. However, there is an anticipation of trending toward higher peaks that require capital investment for a short duration of use. C&LM or distributed generation coupled with energy storage may be used effectively to reduce the peak demands and defer some of the peak load driven investments.

## E. Emerging Technologies Impacting the Forecast of Electrical Demand

### E.1. Electric Vehicles

The concept of electric vehicles (EVs) is not a new one. There have been electric cars in development since the early days of the automobile. However, widespread acceptance and implementation has been restrained by the high cost of EVs and an assortment of technical limitations.

During the oil embargo of the 1970s a major push to roll out electric vehicles and related infrastructure took place but made little headway once gas prices fell and Asian manufacturers such as Honda and Toyota flooded the American market with small, fuel efficient, vehicles. Similarly, when gas prices rose above $4/gallon in 2008 the auto industry accelerated their plans to bring EVs to market.

The success of the Toyota Prius and other hybrid vehicles has made the jump to EVs less daunting – a jump that has been supported by generous tax credits and President Obama's goal of one million EVs in use by 2017. This would represent less than 1 percent of the nation's light-duty vehicle stock[5].

While it is likely that little to no impact will be felt in New Hampshire during the planning period, EVs represent a new electric load that could increase demand for electricity while reducing GHG emissions.

#### E.1.1. EVs Defined

EVs can be split into three broad categories: Plug-In Hybrid Electric Vehicles (PHEVs), Extended Range Electric Vehicles (EREVs), and Battery Electric Vehicles (BEVs). Hybrid vehicles, such as the Prius, are not classified as EVs since they do not plug into the electric grid.

PHEVs are essentially the same as existing hybrid vehicles which have an internal combustion (IC) engine and batteries. The batteries in PHEVs are larger (5-22 kWh) and can be charged from an external power source. Since they have a traditional IC engine they have an unlimited driving range.

[5] U.S. Energy Information Association, Annual Energy Outlook, 2010

EREVs have much larger batteries than PHEVs (16-27 kWh) and can run for extended distances (40-60 miles) on battery power alone. They also have an IC engine that will charge the battery and provide unlimited driving range.

BEVs have no IC engine and must be charged once the battery has run down. These vehicles have the largest batteries (25-35 kWh), but also the longest battery-only range (> 60 miles).

Charging an electric vehicle can be done at either 120 Volts or 240 Volts. The time to fully charge a discharged battery will vary depending on voltage and the battery size. For example, the Nissan Leaf (a BEV expected to come to market in 2011) is anticipated to have a 25-30 kWh battery. At 120V the charging time could exceed 14 hours, while at 240V it would be closer to four hours. Currently, standards exist for charging interfaces which should facilitate larger scale adoption of EV technology.

### E.1.2. Market Penetration

During the time frame of this study the adoption of electric vehicles will be limited to early adopters in major metropolitan areas. It is anticipated that adoption in New Hampshire will be slow due to economic and production factors.

While some EV manufacturers exist (Tesla), larger scale introduction is not expected until late 2010 and 2011 as shown in Exhibit III-20 below. These initial production runs will be small and have limited distribution. Distribution is expected to be centered on large metro areas on either coast of the United States. Boston is one area targeted for the initial roll out which could translate into some EVs making their way into New Hampshire. New Hampshire's relatively long average commute time[6] (25.4 minutes) could also limit early adoption to PHEVs and EREVs.

**Exhibit III-20: Electric Vehicle Introduction**

| Model | Expected Launch |
|---|---|
| Tesla Roadster | now |
| Chevy Volt | late 2010 |
| Nissan Leaf | late 2010 |
| Ford Transit Connect | late 2010 |
| Think City EV | 2010 |
| GM PHEV SUV | 2010-2011 |
| Toyota Prius PHEV | 2011-2012 |
| BMW Active E 1 Series | 2011 |
| Ford Focus EV | 2011 |
| Volvo V70 PHEV | 2012-2013 |
| Cadillac Converi | 2012-2013 |
| Volvo C30 EV | 2012-2013 |
| VW E-Up | 2013 |

Source: Source: Plug In America & Corporate Press Releases

[6] U.S. Census Bureau, 2008 American Community Survey

Economic factors will only serve to limit large-scale adoption to small numbers. The price premium between an EV and a comparable IC powered vehicle could be as much as $20,000. While federal tax incentives will reduce this premium somewhat it will take reduced battery costs and/or sustained higher gasoline prices for these vehicles to broaden their appeal to the mass market. Nonetheless there will be some for which this added cost provides benefit as evidenced by the growing appeal of residential solar and wind installations which produce electricity at above market costs.

Mass adoption by fleets seems to be the area where EVs can have the most impact. As with general consumers, economics will play a large role in determining its success. In addition, fleet adoption will require significantly more charging infrastructure on the consumer's end.

A study by KEMA Inc.[7] projected that, if the President's goal was met, there could be as many as 51,000 consumer EVs in the ISO-New England region by 2017. They estimate that 34,000 (67%) will be in the metro Boston area, Rhode Island, and Connecticut. The report anticipates some adoption in New Hampshire (<10,000), mainly in the Manchester-Nashua corridor.

### E.1.3. Potential Distribution System Impacts

The impact on the distribution system of the adoption of EVs can be broken into two areas: load and price, which are affected by customer charging patterns and specific vehicle needs.

The KEMA study indicates that if EV adoption meets the President's goal the incremental load across the ISO-New England system would range from 50 MW (if charging were staged over 12 hours) to 338 MW (if EVs all charged at the same time). It therefore seems likely that even an optimistic view of EV adoption would not pose any major issues for maintaining reliable electric service across PSNH's distribution system.

Given the range in load, the KEMA study estimates that price effects would be negligible if charging were staged over long periods of time. If all charging took place at once prices across the ISO-New England system would be expected to increase by 2 percent.

### E.1.4. Environmental Impacts

One of the most promising aspects of EV adoption would be its environmental benefits. A modest view of EV penetration in the coming years would suggest only a small environmental benefit with net $CO_2$ and NOx emissions decreasing.

---

[7] Kema Inc., "*Assessment of Plug-In Electric Vehicle Integration with ISO/RTO Systems*", March 2010

# IV. Assessment of Demand-Side Energy Management Programs

This section examines the demand side programs currently offered by PSNH and provides an assessment of potential demand-side resources and possible future offerings. This section presents:

a. an overview of the energy and demand savings achieved by the CORE Programs;
b. the methodology and results of the assessment of the available demand side potential;
c. an economic analysis of energy efficiency program potential;
d. a sensitivity analysis to determine the impact on avoided costs of increasing the cost of $CO_2$ to climate sustainability levels;
e. a look at current and potential demand response and load management programs,
f. a discussion of Distributed Generation options;
g. an examination of other overarching factors that may have a significant impact on demand side activities in New Hampshire; and
h. a description of PSNH's involvement in demand-side research and development activities.

## A. CORE Energy Efficiency Programs

### A.1. Background

PSNH along with the state's other electric utilities launched the CORE Programs in June 2002. There are eight CORE Programs providing products and services tailored for business, residential and income-eligible customers. Each year the New Hampshire electric utilities work together to review the CORE Programs, make adjustments and improvements as needed or suggested by customers, interested parties, Commission Staff, and program administrators. PSNH also has four utility-specific programs designed to explore new ideas and practices not addressed by the CORE Programs or to test new technologies. Since their introduction, the CORE Programs have evolved in response to changing technology, market conditions, program evaluations, and new standards as well as input from customers and other interested parties. PSNH is confident that through a combination of prescriptive and custom incentives the CORE Programs offered today can accommodate nearly any cost-effective electric energy saving technology of interest to our customers. Further, as will be discussed later in this section, with adequate funding the CORE Programs can be expanded to address the available potential in New Hampshire.

### A.2. Impacts on Energy Consumption

The table in Exhibit IV-1 below summarizes PSNH's actual expenditures, lifetime kilowatt-hour savings, and customer participation for 2009, the most recently completed program year. While there are some year-to-year variations, these results are typical of those achieved since the launch of the CORE Programs.

Based on the 2009 results, PSNH saved energy at an average cost of 2.4 cents per lifetime kWh[8] – as compared to the current average retail price of a kWh of 14.65 cents[9]. This overall represents a simple benefit ratio on program investment of more than 6:1. Given that the installed measures have an average life of 12.5 years, the savings will continue well into the future, and should energy costs increase, these comparisons will become even more compelling.

**Exhibit IV-1: 2009 CORE Program Results**

| | Expenditures (Dollars) | Savings (Lifetime kWh) | Customers (Numbers) |
|---|---|---|---|
| **Residential** | | | |
| Energy Star Homes | $830,649 | 16,470,916 | 382 |
| Home Energy Solutions | $1,339,390 | 42,802,639 | 1,553 |
| HES Fuel Neutral Pilot | $437,549 | 1,604,647 | 89 |
| Home Energy Assistance | $1,841,978 | 8,827,996 | 518 |
| Energy Star Lighting | $771,605 | 61,775,768 | 233,053 |
| Energy Star Appliances | $686,352 | 27,393,686 | 10,357 |
| ES Homes – Geothermal | $363,241 | 41,626,175 | 54 |
| | | | |
| **Commercial & Industrial** | | | |
| Small Business Energy Solutions | $2,060,240 | 101,219,283 | 745 |
| Large C&I Retrofit | $2,165,043 | 190,768,341 | 199 |
| New Equipment & Construction | $1,848,255 | 91,377,836 | 179 |
| Educational Programs | $115,061 | | |
| Smart Start Program | $53,851 | | 59 |
| C&I Customer Partnerships | $35,552 | | 2 |
| C&I RFP Pilot Program | $280,795 | 12,656,943 | 3 |
| | | | |
| **PSNH TOTAL** | $12,829,561 | 596,524,230 | 247,193 |

## A.3. Impacts on Capacity

In addition to the energy savings discussed above, the CORE Programs also provide capacity reductions. On June 16, 2006, the FERC approved a Settlement Agreement that addressed the future capacity needs of New England and laid the groundwork for the Forward Capacity Market. Effective December 1, 2006, under FCM Transition Period rules, the ISO-New England was obligated to pay for qualified capacity reductions in accordance with a determined rate schedule from December 1, 2006 to May 31, 2010.

In order to qualify for payments, capacity reductions must have been installed after June 16, 2006, and the organization seeking payment must certify to ISO-New England's satisfaction that the capacity reductions are operational during hours of peak electrical usage. PSNH has developed the necessary reporting and Measurement and Verification (M&V) plans needed to evaluate the impact of efficiency measures at the time of system peak and thus the capacity reduction value that qualifies for ISO-New England payments. In addition, prior to payment, ISO-New England also requires monthly reporting of all

---

[8] The 2.4¢/kWh cited here includes the shareholder incentive of $1,478,171.

[9] Source: NH Office of Energy and Planning, fuel prices as of August 2, 2010.

claimed capacity reductions. PSNH's CORE Program capacity reductions, as qualifying passive demand resources, successfully participated in the FCM Transition Period which ended on May 31, 2010.

June 1, 2010, marked the beginning of ISO-New England's Forward Capacity Market in which capacity obligations are awarded through an annual auction. PSNH successfully used its CORE Program capacity reductions to secure supply obligations – and capacity payments on behalf of its customers – in each of the first three auctions. In each of these auctions and in accordance with ISO-New England Market Rules, PSNH opted to receive the auction clearing price for its capacity reductions for five years. Consequently, the Company has capacity supply obligations and corresponding revenues which run through May 31, 2017.

In addition, PSNH participated in the fourth Forward Capacity Auction which took place on August 2, 2010. PSNH intends to take all necessary steps to continue to qualify capacity supply obligation from the CORE Program capacity reductions in future Forward Capacity Auctions. Clearing prices applicable to the CORE Program capacity reductions for the following Forward Capacity Auctions are as follows:

**Exhibit IV-2: Forward Capacity Auction Clearing Prices**

| Period | FCA Clearing Price |
|---|---|
| FCA 1 – June 1, 2010 to May 31, 2011 | $4.50 / kW-month |
| FCA 2 – June 1, 2011 to May 31, 2012 | $3.60 / kW-month |
| FCA 3 – June 1, 2012 to May 31, 2013 | $2.951 / kW-month |
| FCA 4 – June 1, 2013 to May 31, 2014 | $2.951 / kW-month |

As part of the qualification process required by ISO-New England, PSNH has to file a Qualification Package. The latest Qualification Package filed for the fourth Forward Capacity Market included PSNH's estimate of the so-called "new capacity" reductions that will be installed between June 1, 2012, and May 31, 2013. For the commitment period June 1, 2013, through May 31, 2014, the total capacity reductions include the "new capacity" bid into the fourth auction plus the existing capacity still performing and qualified from earlier auctions. A Qualification Package for the fifth Forward Capacity Market for the period June 1, 2014, to May 31, 2015, will be filed in October 2010.

The impact of the CORE Programs' capacity reductions on system peak is constantly changing due to the installation of new measures and the end of useful life of older measures. Exhibit IV-3 shows the cumulative capacity reductions resulting from operable CORE Program efficiency measures installed between June 16, 2006, and May 31, 2010, and coincident with the New England system peak.

**Exhibit IV-3: CORE Program Capacity Reductions**
**Based On Measures Installed Between June 16, 2006 and May 31, 2010**

| | Coincident With ISO-New England Peak | |
|---|---|---|
| | **Summer kW** | **Winter kW** |
| **Residential** | | |
| ENERGY STAR Homes | 123.1 | 493.8 |
| Home Energy Solutions | 510.8 | 1,306.2 |
| Home Energy Assistance | 445.1 | 830.7 |
| ENERGY STAR Lighting | 2,521.2 | 9,487.9 |
| ENERGY STAR Appliances | 609.2 | 763.0 |
| Residential Utility Specific | 36.4 | 1,286.7 |
| **Total Residential** | **4,245.8** | **14,168.3** |
| | | |
| **Commercial & Industrial** | | |
| Small Business Energy Solutions | 5,942.4 | 4,351.8 |
| Large C & I Retrofit | 8,737.3 | 6,546.5 |
| New Equipment & Construction | 5,453.0 | 3,855.4 |
| C & I Utility Specific | 618.3 | 532.5 |
| **Total Commercial & Industrial** | **20,751.0** | **15,286.2** |
| | | |
| Grand Total (June 16, 2006 – May 31, 2010) | 24,996.9 | 29,454.5 |
| Average kW/Month | 526.2 | 620.1 |
| | | |
| **Annualized Coincident Capacity Savings** | **6,315.0** | **7,441.1** |

## A.4. The CORE Programs as a Demand-Side Resource

In summary, each year the CORE Programs implemented by PSNH save approximately 700 million $kWh_{lifetime}$ and reduce the coincident New England peak by 6.3 MW at a cost of $14.6 million. The average measure life is 12 years.

In applying this resource it is important to consider several restrictions imposed by New Hampshire legislation. The first has to do with targeting the CORE Programs to specific customers. For example, examining Exhibit IV-1 it becomes evident that the cost to save a kWh for a business customer is about twice that needed to save a kWh for a residential customer. Shifting program dollars to the commercial and industrial sector would yield more kWh savings per dollar spent. However, PSNH believes that the enabling legislation[10] for the CORE Programs requires that the System Benefits Charge revenues be allocated to customers in proportion to the amount collected from each customer class.

Reliability is another important consideration when evaluating the CORE Programs as a means of meeting the energy and capacity needs of PSNH's customers. In general the key factor in determining their ability to perform when needed is their measure life. Unlike

[10] RSA 374-F:3.VI: BENEFITS FOR ALL CONSUMERS states in part, "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…"

some other demand resources, once installed, CORE Program measures do not require periodic renewal of customer participation agreements or ongoing customer incentive payments. Furthermore, the claimed capacity reductions are always "on" and do not depend upon PSNH's staff, customer personnel, or communication equipment for activation. As a result, CORE Program measures are highly reliable.

## A.5. Base Case Scenario

A Base Case Scenario was developed as a projection of energy efficiency program costs and savings assuming that program funding continues at the current level. This scenario incorporates the following key elements:

- Program design, with the exception of Energy Star Lighting noted below, remains unchanged.
- The 2011 budget, savings, and participation are set equal to the nominal 2010 filed values.
- The 2012-2015 budget, savings and participation are set equal to the 2011 values, except for the revisions noted as follows:
    - The 2012-2015 budgets are escalated from the 2011 budget at the general inflation rate.
    - The Energy Star Lighting retail CFL participation values are scaled down for the period 2012-2015 to reflect the phase-in of the EISA standards.
    - The reductions in the Energy Star Lighting budget are re-allocated to the Utility-Specific Other budget.
    - Participation levels were reduced in the Energy Star Homes, Home Energy Assistance and Large C&I Retrofit programs to compensate for increasing customer incentive levels.

Exhibit IV-4 presents projected annual program expenditures, annualized electric savings (MWh), lifetime electric savings (MWh) and annualized peak demand savings (MW) for the Base Case Scenario. Annual program expenditures are escalated at an annual inflation rate of 1.6 percent. Annualized savings represent the estimated savings at the meter from all measures installed during the corresponding year, assuming that all measures are installed at the beginning of the year. This convention is consistent with the annual CORE Program filings and benefit-cost analysis as well as the Potential Study conducted for the Commission by GDS Associates. Lifetime savings were calculated based on an assumed average life for each measure category.

**Exhibit IV-4: Base Case Scenario**

| Year | EE Program Expenditure | Annualized Savings (MWh) | Lifetime Savings (MWh) | Winter Peak Savings (MW) | Summer Peak Savings (MW) |
|---|---|---|---|---|---|
| 2010 | $ 14,129,191 | 41,198 | 452,209 | 8.6 | 8.4 |
| 2011 | $ 14,129,191 | 39,075 | 429,526 | 8.3 | 8.1 |
| 2012 | $ 14,349,606 | 37,048 | 418,638 | 7.8 | 7.9 |
| 2013 | $ 14,573,460 | 34,312 | 404,557 | 7.2 | 7.8 |
| 2014 | $ 14,800,806 | 28,133 | 373,221 | 5.8 | 7.4 |
| 2015 | $ 15,031,698 | 28,102 | 372,824 | 5.8 | 7.4 |

The 2010 PSNH CORE Program budgeted expenditures and projected savings reported in the *2010 CORE New Hampshire Energy Efficiency Programs* filing (Attachment F) are presented here for comparison. The projected decline in annualized MWh savings is the result of the phase-in of the EISA standards and the corresponding reduction in Energy Star Lighting savings from CFLs. Exhibit IV-5 presents the expenditure and savings projections by customer sector. The effect of the reduction in Residential lighting savings is clearly illustrated in contrast to the constant savings projection for C&I programs. Estimated savings from CFLs purchased through the retail component of the Energy Star Lighting program account for 70 percent of the 2010 level of annualized savings.

**Exhibit IV-5: Base Case Scenario by Customer Sector**

| Year | Residential Program Expenditure | C&I Program Expenditure | Residential Annualized Savings (MWh) | C&I Annualized Savings (MWh) |
|---|---|---|---|---|
| 2010 | $ 6,636,557 | $ 7,492,634 | 15,185 | 26,013 |
| 2011 | $ 6,636,557 | $ 7,492,634 | 15,056 | 24,019 |
| 2012 | $ 6,740,087 | $ 7,609,519 | 13,028 | 24,019 |
| 2013 | $ 6,845,233 | $ 7,728,227 | 10,292 | 24,019 |
| 2014 | $ 6,952,018 | $ 7,848,788 | 4,113 | 24,019 |
| 2015 | $ 7,060,470 | $ 7,971,229 | 4,083 | 24,019 |

The projected Base Case Scenario program expenditures are presented in Exhibit IV-6.

**Exhibit IV-6: Base Case Scenario Program Expenditures**

| Program | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|
| Home Energy Assistance | $ 2,136,334 | $ 2,136,334 | $ 2,169,660 | $ 2,203,507 | $ 2,237,882 | $ 2,272,793 |
| NH Home Perf. w/ Energy Star | $ 1,620,080 | $ 1,620,080 | $ 1,645,354 | $ 1,671,021 | $ 1,697,089 | $ 1,723,564 |
| EnergyStar Homes | $ 945,047 | $ 945,047 | $ 959,790 | $ 974,762 | $ 989,969 | $ 1,005,412 |
| EnergyStar Appliances | $ 630,031 | $ 630,031 | $ 639,860 | $ 649,842 | $ 659,979 | $ 670,275 |
| EnergyStar Lighting | $ 945,047 | $ 945,047 | $ 918,829 | $ 875,385 | $ 755,253 | $ 767,035 |
| HeatSMART | $ - | $ - | $ - | $ - | $ - | $ - |
| ES Homes - Geothermal | $ 360,018 | $ 360,018 | $ 365,634 | $ 371,338 | $ 377,131 | $ 383,014 |
| U-S: Other | $ - | $ - | $ 40,961 | $ 99,377 | $ 234,715 | $ 238,377 |
| **Residential Total** | **$ 6,636,557** | **$ 6,636,557** | **$ 6,740,087** | **$ 6,845,233** | **$ 6,952,018** | **$ 7,060,470** |
| | | | | | | |
| SmartStart | $ 50,000 | $ 50,000 | $ 50,780 | $ 51,572 | $ 52,377 | $ 53,194 |
| Customer Partnerships | $ 30,000 | $ 30,000 | $ 30,468 | $ 30,943 | $ 31,426 | $ 31,916 |
| New Equipment & Construction | $ 1,958,884 | $ 1,958,884 | $ 1,989,443 | $ 2,020,478 | $ 2,051,998 | $ 2,084,009 |
| Large C&I Retrofit | $ 2,466,743 | $ 2,466,743 | $ 2,505,224 | $ 2,544,306 | $ 2,583,997 | $ 2,624,307 |
| Small Business Energy Solutions | $ 2,321,641 | $ 2,321,641 | $ 2,357,858 | $ 2,394,641 | $ 2,431,997 | $ 2,469,936 |
| RFP Program | $ 507,859 | $ 507,859 | $ 515,781 | $ 523,828 | $ 531,999 | $ 540,299 |
| Education | $ 157,507 | $ 157,507 | $ 159,964 | $ 162,460 | $ 164,994 | $ 167,568 |
| **C&I Total** | **$ 7,492,634** | **$ 7,492,634** | **$ 7,609,519** | **$ 7,728,227** | **$ 7,848,788** | **$ 7,971,229** |
| | | | | | | |
| **Program Total** | **$14,129,191** | **$14,129,191** | **$14,349,606** | **$14,573,460** | **$14,800,806** | **$15,031,698** |

## B. Demand Side Potential

In Order No. 24,945, the Commission directed PSNH to base its assessment of demand-side resources on the results reported in a study conducted by GDS Associates documented in the January 2009 report, *Additional Opportunities for Energy Efficiency in New Hampshire* (GDS Study) prepared for the New Hampshire Public Utilities Commission. The following sections discuss potential demand side programs in further detail.

## B.1. Methodology

### Overview

An analysis of demand-side resource potential was conducted in order to quantify the annual costs and benefits that can be achieved through concerted programmatic efforts to promote the installation of energy-efficient measures in the homes and commercial/industrial facilities within PSNH's service territory. The resource assessment embodies three fundamental criteria:

- Cost-Effectiveness – The value of the savings must be expected to exceed the cost of implementation. The Total Resource Cost (TRC) Test required by the Commission was accordingly employed in the economic analysis of demand-side measures in order to provide reasonable assurance that their implementation will result in an efficient allocation of scarce resources.
- Market Acceptance – The purchase and installation of efficient products and services depends on decisions made by consumers and suppliers that reflect their economic priorities, opportunity costs, technical resources, and access to investment capital.

Thus, the ultimate realization of the resource potential is a function of market acceptance.

- Market Transition – The CORE Programs developed and administered by the electric utility companies constitute a successful collaboration among the program administrators, product vendors, implementation contractors, and public policy agencies. These programs provide consumers, homeowners, and businesses with information, technical assistance, and financial incentives to facilitate investment decisions that produce significant economic benefits. A substantial increase in the purchase and installation of energy efficient equipment necessarily requires the recruitment of additional resources to expand customer awareness of existing programs, increased contractor and vendor participation, and development of enhanced marketing and implementation processes, all of which take time to further transform the markets.

The analysis of demand-side resource potential utilized a methodology that is based on GDS Study. The details of the methodology are described in the sections below.

Definition of Demand Side Potential

The assessment of Demand Side Potential was based on the electric energy (MWh) savings potential estimate reported in the GDS Study. GDS developed four different estimates of energy efficiency potential:

- Technical Potential
- Maximum Achievable Potential
- Maximum Achievable Cost Effective (MACE) Potential
- Potentially Obtainable Scenario

These estimates represent a hierarchy of defined potential starting at the broadest level of technical feasibility and then introducing progressively more restrictive criteria of achievability based on market turnover, cost-effectiveness, and market acceptance. Achievable Potential is essentially an annualized level of savings resulting from "market-driven" opportunities for technically feasible efficiency upgrades to equipment and building systems during replacement or additions to the existing stock. The point of departure for the present analysis was the **Potentially Obtainable Scenario**, defined by GDS as:

> *"the potential for the realistic penetration over time of energy efficient measures that are cost effective according to the NH TRC, taking customer behavior into consideration (including consideration of priorities and price). To achieve this potential, a concerted, sustained campaign involving aggressive programs and market interventions would be required. As demonstrated later in this report, the State of New Hampshire and its electric and gas utilities would need to continue to undertake, and perhaps aggressively expand its efforts to achieve these levels of savings."* (GDS Study, p. 4)

The objective of the analysis performed for the LCIRP was the production of a **Market Potential Scenario** based on the GDS Potentially Obtainable Scenario. The methodology undertaken by PSNH to perform this analysis consisted of the following tasks:

1. Review of the Potentially Obtainable methodology and results;
2. Translation of the Potentially Obtainable savings data from 10-year state-wide estimates into annualized savings values specific to PSNH;
3. Identification of major measure/end use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009;
4. Identification of the measures (priority measures) within each major category that account for the majority of potential savings in that category;
5. Review and revision (if warranted) of the technical/market assumptions employed in the development of potential savings estimates for the priority measures;
6. Selection of priority measures for inclusion in the Market Potential Scenario;
7. Determination of the program design elements, customer incentive levels and other program costs required to achieve the estimated market potential;
8. Development of Market Potential Scenario annual program participation, cost and savings projections for the planning period 2011-2015;
9. TRC analysis of Market Potential Scenario.

Each task is described in detail in the following section.

Market Potential Methodology

1. Review of Potentially Obtainable Scenario
   The methodology employed by GDS to develop the Potentially Obtainable Scenario was reviewed in order to evaluate and utilize the results in the development of PSNH's Market Potential Scenario for the LCIRP. As documented in the study report, GDS utilized a comprehensive modeling approach to analyze the state-wide energy efficiency electric and non-electric savings potential in all customer sectors. Separate models were developed for the Residential, Commercial and Industrial sectors. The model inputs consist of a combination of measure-specific and end-use specific technical, market and forecast sales data that were developed via primary and secondary data collection efforts described in the report. Energy savings, costs, and various market parameters were analyzed for hundreds of energy-saving measures. Every measure was analyzed for cost-effectiveness in order to estimate the aggregate cost-effective potential in New Hampshire.

2. Translation of Potentially Obtainable savings into Annualized Savings Specific to PSNH
   The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customer facilities within PSNH's service territory. The GDS electric savings potential results were therefore reduced by a factor derived from PSNH's percent of New Hampshire forecasted sales by customer sector.

   The GDS Study quantified Demand Side Potential savings in terms of annualized MWh savings in 2018 based on ten years of implementation of energy efficiency measures. The Maximum Achievable potential, defined as the "maximum penetration of an efficient measure that would be adopted absent consideration of cost or customer behavior", is based on "realistic penetration levels that can be achieved by 2018 if all remaining standard efficiency equipment were to be replaced on burnout (at the end of its useful measure life) and where all new construction and major renovation activities in the state were done using energy efficient equipment and construction/installation practices." The "achievable" potential savings that can be realized over a specified number of years is accordingly determined by the maximum number of program participants per year (market penetration limit), which is a function of the expected useful life of existing equipment and the new construction and major renovation markets, multiplied by the number of years. The Obtainable Potential (OP) is a subset of the Maximum Achievable potential, as defined above, after all measure applications are screened for cost-effectiveness and savings estimates are adjusted to account for market acceptance.

PSNH's Market Potential Scenario represents a projection of savings assuming an aggressive expansion of the current energy efficiency programs within PSNH's service territory over the period 2011-2015. The market transition process, discussed above, would entail a period of program ramp-up beginning in 2011. Therefore the Market Potential Scenario projections of annual program costs, participation, and savings reflect a substantial increase from current levels in order to attain the level of Obtainable Potential savings in 2015. This potential savings level represents cost-effective efficiency upgrades in the equipment replacement, new construction and major renovation markets as well as opportunities to retrofit existing equipment and facilities (e.g. controls and shell improvements). The projected 2015 savings is therefore constrained by the annual rates of equipment turnover, renovation, and new construction. Success will also hinge on customers' willingness and financial wherewithal to implement measures at a much higher level than is currently the case. Retrofit measure savings, as noted by GDS, "can theoretically be captured at any time; however, in practice it takes many years to retrofit an entire stock of buildings, even with the most aggressive of efficiency programs." The GDS potential calculations were calculated by multiplying the annual obtainable savings by ten to reflect a ten-year period of implementation. The 2015 annualized Market Potential savings is therefore quantified as one-tenth of the corresponding GDS values, i.e. the annual penetration limit.

3. <u>Identification of Measure Categories with Significant Remaining Potential</u>
   The Obtainable Potential savings, annualized and adjusted for PSNH's service territory, were analyzed by sector and major measure (end use) category in order to identify the major measure/end-use categories in which the estimated potential savings significantly exceeds PSNH's CORE program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission September 30, 2009. If the current savings goal was approximately equal to the potential savings estimate, then the Market Potential Scenario projection would incorporate the current program savings projections. If the estimated potential significantly exceeded current program savings levels, then additional analysis was performed, as described below.

4. <u>Identification of Priority Measures</u>
   Each measure category was analyzed to prioritize the individual measures within the category in terms of the magnitude of potential savings. The measures that

account for a significant portion of the potential savings were assigned a high priority for technical review.

5. Review and Revision of Technical Assumptions
The GDS modeling assumptions employed in the calculation of potential savings of priority measures were reviewed for reasonableness and consistency with CORE Program assumptions and experience. As reported in the GDS Study, most of the cost-effective measures analyzed by GDS are available through the current New Hampshire Energy Efficiency programs. For those measures, PSNH's savings and costs per participant were utilized in the development of the Market Potential Scenario. PSNH's unit savings and costs are derived from actual program implementation experience in its service territory and are based on a combination of project-specific and CORE Program common assumption data that are utilized in the annual CORE Program filing which is reviewed by the Commission. Utilization of PSNH's unit savings and cost assumptions represents a modification to the cost per kWh saved but not to the magnitude of the potential savings. The Market Potential Scenario participation was adjusted to achieve the total potential savings in 2015. However in certain cases, discussed below, the magnitude of the potential savings was revised to reflect more reasonable assumptions pertaining to measure savings or potential participation levels.

   Apart from revisions to measure-specific assumptions, there are two factors, discussed in more detail below, which effectively reduced the Residential sector savings potential by more than 50 percent. The GDS Study did not account for the Energy Independence and Security Act of 2007 (EISA) provisions concerning lighting standards that go into effect in 2012. This factor alone accounts for over 40 percent of reported potential savings that, in light of the EISA standards, is not obtainable in 2015. The other factor relates to program design considerations. There are several priority measures that entail the replacement of appliances with Energy Star qualified equipment instead of with standard efficiency models. While increased penetration of Energy Star appliances can make a significant contribution to potential savings, their incremental cost is essentially zero or sufficiently low to be inconsequential as a factor in the purchasing decision. The Market Potential Scenario provides for marketing efforts to inform customers of these energy savings opportunities, but it is difficult to quantify the impact of marketing on penetration levels with the precision required to establish program savings goals.

6. Selection of Priority Measures for Market Potential Scenario
The LCIRP Market Potential Scenario was developed as a five-year projection of annual costs and savings that could reasonably be achieved within a program implementation framework similar to the energy efficiency programs currently operating in New Hampshire. The projections accordingly contain the same elements as the annual CORE Program plans: a) annual program budgets, including customer rebates, contractor costs, administrative, marketing and evaluation costs, b) annual program savings and participation goals and c) a quantification of program benefits in terms of the projected value of energy and capacity savings.

   As such, the scenario is constructed upon detailed assumptions regarding measure category or end-use level savings and costs per participant in accordance with the best data available from the GDS Study, CORE Program experience, and secondary sources. As explained in the GDS Study (p. 62), the methodology employed to estimate savings potential varied according to customer sector. The Residential analysis was based on a "bottom-up" approach which quantified the size of each market for each measure in terms of the number of units of equipment or housing and the associated savings per measure. The Commercial and Industrial analyses were based instead on a "top-down" approach in which annual electric consumption was allocated to each building type and end use to which a measure-specific savings factor was applied. The Industrial sector analysis was modeled at the end-use level instead of the more detailed measure level of disaggregation.

The Market Potential Scenario reflects the corresponding level of disaggregation employed in the GDS Study, i.e. a more detailed disaggregation of savings potential in the Residential sector than in the Commercial and Industrial sectors. This is to a great extent a practical necessity given the much greater heterogeneity of building size, building systems, end-use applications and equipment types in the C&I sectors. Because of the broad range of diversity of measures and applications, PSNH's C&I programs currently provide rebates and technical assistance for "custom" projects via the Large Retrofit and RFP programs. These program delivery channels can accommodate almost all energy efficiency measures considered in the GDS Study.

The inclusion of priority measures in the Market Potential Scenario was modeled as follows. If a specific category of measures is not currently supported by the energy efficiency programs, it was explicitly incorporated in the analysis based on savings, cost and participation assumptions for that measure category. If a category of measures is currently supported by the energy efficiency programs, then the level of participation was increased over the planning period (2011-2015) in order to attain the potential savings level by 2015. In some cases the savings per measure category was increased to reflect a more comprehensive set of measures than what the category currently comprises.

Certain priority measures were not included in the scenario because of program design considerations, discussed in the following section.

7. Market Potential Program Design

As noted above, the Market Potential Scenario was developed within a program implementation framework in order to comprehensively account for program delivery costs, program design elements and the market transition process required to substantially expand the scope and magnitude of program savings and participation.

The GDS Study was not developed to represent a particular program planning scenario. The estimated potential savings reflects a level that is reasonably obtainable once an aggressive program portfolio has been placed into operation and "ramped up" over some period of time. In other words, the GDS Study did not attempt to model the program and market transition from the current state to a level that represents the market potential penetration of efficient measures. The GDS estimated implementation costs account for the incremental installed cost of the measures, but not program delivery, marketing and evaluation costs. Analysis of specific program design elements, implementation strategies, infrastructure development and marketing channels that would be required to achieve the potential savings were not within the scope of the study (see GDS Study p. 18).

Fortunately, the current CORE Program portfolio provides a foundation of technical resources, including implementation and marketing contractors, product suppliers and other trade allies which can serve as the point of departure for expanded implementation of energy efficiency services. The Market Potential Scenario is therefore based conceptually and analytically on the utilization and expansion of the program delivery and marketing channels, contractor and supplier infrastructure and customer incentive policies currently in operation through existing programs.

The GDS Obtainable Potential scenario was based on the assumption that program rebates would be sufficient to pay for at least fifty percent of the incremental energy efficiency measure cost in order to induce customers to purchase the higher-efficiency equipment. The Market Potential Scenarios therefore assumes that the customer rebate levels equal either 50 percent of the incremental (Total Resource) measure cost or current program rebate levels. Current rebate levels are assumed if a) the current levels are greater than 50 percent or b) the current levels are sufficient to attain potential savings, as discussed below. The GDS rebate of 50 percent must be regarded in this context as a generic modeling assumption pending measure and program-specific analysis that would be conducted as part of the development of program implementation plans. As usual, program rebate levels would be subject to further revision on the basis of the market response to the program as well as general market trends in the demand and supply of efficient products and services.

The incremental cost of certain priority measures (e.g., Energy Star refrigerators) is so low (<5%) that the cost is not likely to be a decisive factor in the purchasing decision. In such cases the payment of a financial incentive to the consumer would not be an effective use of the System Benefit Charge funds. In lieu of consumer rebates it would be preferable to allocate funds to marketing efforts designed to raise customer awareness of efficient products and inform them of the benefits of these products. This approach is reflected in the Market Potential Scenario program budget but there is no corresponding projection of energy savings because of the difficulty, mentioned earlier, in attributing changes in the penetration of efficient products to program marketing efforts.

Marketing is nevertheless an important component of the Market Potential Scenario. In addition to current marketing activities and increased emphasis on the dissemination of information to consumers about the benefits of energy efficient products, the GDS Study identified the potential to increase customer awareness of the New Hampshire Energy Efficiency Programs, particularly in the Residential sector.

In addition to increased rebates, the annual program budget projections also include increasing implementation contractor costs, marketing costs, internal implementation costs and program evaluation costs.

8. Development of Market Potential Scenario
   The Market Potential Scenario was developed by increasing program participation from current levels over the period 2011-2015 in order to reach the amount of annualized potential savings in 2015. Once the annual participation trends were set, then the annual savings and costs were calculated on the basis of assumed cost and savings per participant for each measure category.

9. TRC Analysis of Market Potential Scenario
   An economic analysis of the Market Potential Scenario was conducted utilizing the Total Resource Cost Test. The details of the benefit-cost analysis methodology are described in Section A.3.

## B.2. Energy Efficiency Program Potential Savings and Costs

**Summary of Results**

As explained in detail in the following section, the Market Potential Scenario projections are based on increased market penetration in the following priority measure categories identified in the review of the GDS results:

- Expansion of HVAC, refrigeration, and process measure installations in all existing Commercial and Industrial facilities
- Addition of a retro-commissioning service component as part of the program serving large Commercial and Industrial customers
- Expansion of the Residential Energy Star Homes program
- Expansion of the New Hampshire Home Performance with Energy Star program
- The addition of a Residential second refrigerator removal service component
- Expansion of Residential LED and outdoor lighting control penetrations
- Expansion of smart power strip penetration

Exhibit IV-7 presents projected annual program expenditures, annualized electric savings (MWh), lifetime electric savings (MWh) and annualized peak demand savings (MW) for the Market Potential Scenario. Annual program expenditures are escalated at an annual inflation rate of 1.6 percent. Annualized savings represent the estimated savings at the meter from all measures installed during the corresponding year, assuming that all measures are installed at the beginning of the year. This convention is consistent with the GDS presentation of results and the annual CORE Program filings and benefit-cost analysis. Lifetime savings were calculated based on an assumed average life for each measure category.

The 2010 PSNH CORE Program budgeted expenditures and projected savings reported in the *2010 CORE New Hampshire Energy Efficiency Programs* filing (Attachment F) are presented here for comparison. Projected expenditures in 2015 are approximately 2.5 times the amount of current expenditures. Annualized MWh savings in 2015 are 68 percent higher than current projections. The increase in expenditures is greater than the increase in savings because:

- Customer incentives were increased to 50 percent of the incremental cost of measures for which current incentives were substantially lower than 50 percent, per the GDS assumption discussed above under program design considerations.
- The priority measures in the Residential sector generally entail greater expenditures per kWh saved than the lighting measures that are being phased out by federal standards (see below).
- Residential marketing costs were increased to improve program awareness, per the GDS survey findings and recommendations, and to inform customers regarding the benefits of energy efficient products.

**Exhibit IV-7: Market Potential Scenario**

| Year | EE Program Expenditure | Annualized Savings (MWh) | Lifetime Savings (MWh) | Winter Peak Savings (MW) | Summer Peak Savings (MW) |
|---|---|---|---|---|---|
| 2010 | $ 14,129,191 | 41,198 | 452,209 | 8.6 | 8.4 |
| 2011 | $ 18,943,345 | 47,243 | 528,668 | 9.7 | 10.2 |
| 2012 | $ 22,815,951 | 52,081 | 600,266 | 10.5 | 12.7 |
| 2013 | $ 27,376,176 | 58,159 | 693,808 | 11.6 | 15.6 |
| 2014 | $ 31,616,372 | 60,639 | 765,344 | 11.9 | 18.3 |
| 2015 | $ 35,799,709 | 69,332 | 867,138 | 13.6 | 21.3 |

The projected level of annualized MWh savings in 2015 amounts to approximately two thirds of the GDS Obtainable Potential level of savings. Exhibit IV-8 presents the expenditure and savings projections by customer sector. There is a marked contrast between the savings projections for the Residential and Commercial and Industrial (C&I) customer sectors. In this scenario C&I savings are projected to ramp up to a level in 2015 that is approximately equal to the GDS Obtainable Potential savings, while Residential savings in 2015 are projected to be lower than the 2010 filed projection.

**Exhibit IV-8: Market Potential by Customer Sector**

| Year | Residential Program Expenditure | C&I Program Expenditure | Residential Annualized Savings (MWh) | C&I Annualized Savings (MWh) | Res. Summer Peak Savings (kW) | C&I Summer Peak Savings (kW) |
|---|---|---|---|---|---|---|
| 2010 | $ 6,636,557 | $ 7,492,634 | 15,185 | 26,013 | 1,288 | 7,153 |
| 2011 | $ 9,840,285 | $ 9,103,061 | 17,651 | 29,592 | 1,709 | 8,504 |
| 2012 | $11,671,748 | $11,144,204 | 16,997 | 35,084 | 1,770 | 10,906 |
| 2013 | $14,071,746 | $13,304,429 | 16,177 | 41,983 | 1,904 | 13,699 |
| 2014 | $16,098,057 | $15,518,315 | 11,758 | 48,882 | 1,790 | 16,491 |
| 2015 | $18,001,673 | $17,798,036 | 13,551 | 55,781 | 2,041 | 19,284 |

The primary factor that accounts for this trend is the effective elimination of potential savings from compact fluorescent lamps (CFLs) by 2014 as a result of the EISA standards discussed in Section A.1. Estimated savings from CFLs purchased through the retail component of the Energy Star Lighting program account for 70 percent of the 2010 level of annualized savings.

The magnitude of the effect of the EISA standards is illustrated by the Base Case Scenario projection of savings based on the continuation of the existing energy efficiency programs at current funding levels (see Section B.5). Exhibits IV-9 and IV-10 present a comparison of the expenditures and annualized MWh savings for the Market Potential and Base Case scenarios.

**Exhibit IV-9: Market Potential and Base Case Savings**

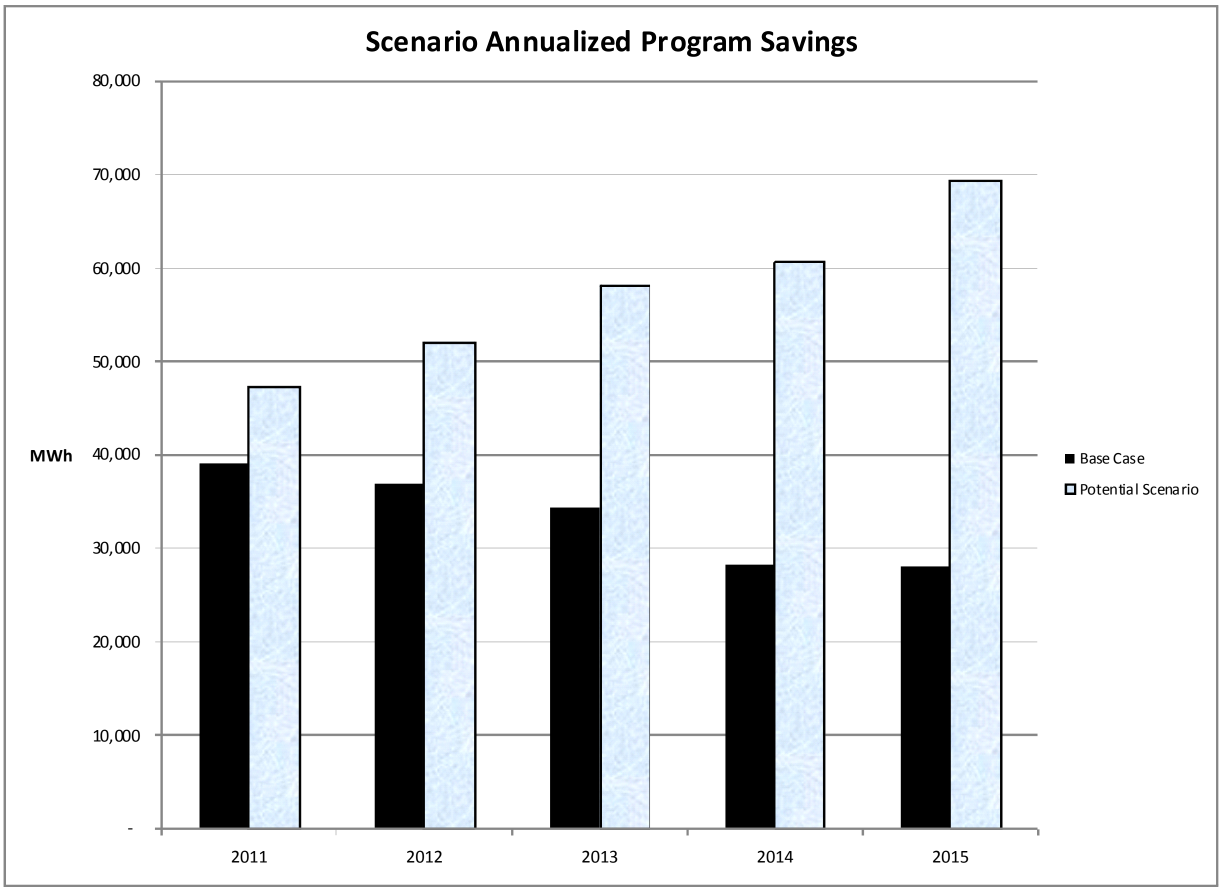



**Exhibit IV-10: Market Potential and Base Case Expenditures and Savings**

| | **Expenditures** | | **Savings (MWh)** | |
|---|---|---|---|---|
| Year | Base Case | Potential Scenario | Base Case | Potential Scenario |
| 2011 | $14,129,191 | $18,943,345 | 39,075 | 47,243 |
| 2012 | $14,349,606 | $22,815,951 | 37,048 | 52,081 |
| 2013 | $14,573,460 | $27,376,176 | 34,312 | 58,159 |
| 2014 | $14,800,806 | $31,616,372 | 28,133 | 60,639 |
| 2015 | $15,031,698 | $35,799,709 | 28,102 | 69,332 |

Thus while the 2015 potential savings projection is 68 percent higher than the 2010 projection, as presented in Exhibit IV-7, it is 147 percent higher than the amount of the corresponding 2015 Base Case projection.

**Commercial and Industrial (C&I) Sector Potential Analysis and Results**

Analysis of Remaining Potential and Identification of Priority Measures

The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customer facilities within PSNH's service territory. The GDS electric savings results were therefore reduced by a factor derived from the PSNH's percent of New Hampshire forecasted sales by customer sector. The Commercial and Industrial factors are respectively 76 percent and 71 percent.

The GDS Obtainable Potential results for the Commercial and Industrial sector were annualized as described in Section A.1. The Obtainable Potential savings, annualized and adjusted for PSNH's service territory, were analyzed in order to identify the major measure/end-use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009.

Exhibit IV-11 presents a comparison of the GDS Obtainable Potential annualized MWh savings to PSNH's savings projection reported in the 2010 program plans. This comparison indicates that the current level of energy efficiency program activity is able to achieve the Obtainable Potential savings in New Construction and from the installation of Lighting measures in existing buildings. On the other hand, there remains significant potential to achieve additional savings in the HVAC and Other measure categories in existing buildings.

**Exhibit IV-11: C&I Comparison of Obtainable Potential to Current Savings**
(Annualized MWh)

| Measure Category | Obtainable Potential | 2010 CORE Savings | 2015 Market Potential |
|---|---|---|---|
| New Construction | 2,866 | 5,642 | 5,834 |
| Existing Lighting | 15,211 | 15,452 | 15,452 |
| Existing HVAC | 12,350 | 682 | 12,350 |
| Existing Other | 22,145 | 4,238 | 22,145 |
| Total C&I | 52,572 | 26,013 | 55,781 |

Exhibit IV-12 presents a breakdown of the potential savings from Heating Ventilation and Air Conditioning (HVAC) measures in the C&I sector. The Industrial savings component is presented as a single category because the GDS analysis of the Industrial sector savings potential was conducted at the end-use level and therefore was not further disaggregated into different measure types. As reported in the study, most of the HVAC measures are supported by the existing PSNH CORE Programs. Technical assistance and customer rebates are available for unitary and split systems, chillers and HVAC controls, including variable-speed controls of pumps and fans, dual enthalpy economizers and demand control ventilation.

The largest single subcategory of HVAC potential savings is associated with commercial HVAC controls. The HVAC control measure with the largest potential savings is retro-commissioning, which accounts for 34 percent of potential HVAC savings in the commercial sector. Retro-commissioning is a systematic investigation process to optimize an existing building's performance. Significant savings can be achieved through the implementation of relatively low-cost operational and maintenance improvements. The CORE Programs do not currently include retro-commissioning services to commercial and industrial customers. Therefore the Market Potential Scenario explicitly incorporates retro-commissioning services as an expansion of the Large C&I Retrofit program.

**Exhibit IV-12: C&I Existing Potential HVAC Savings**

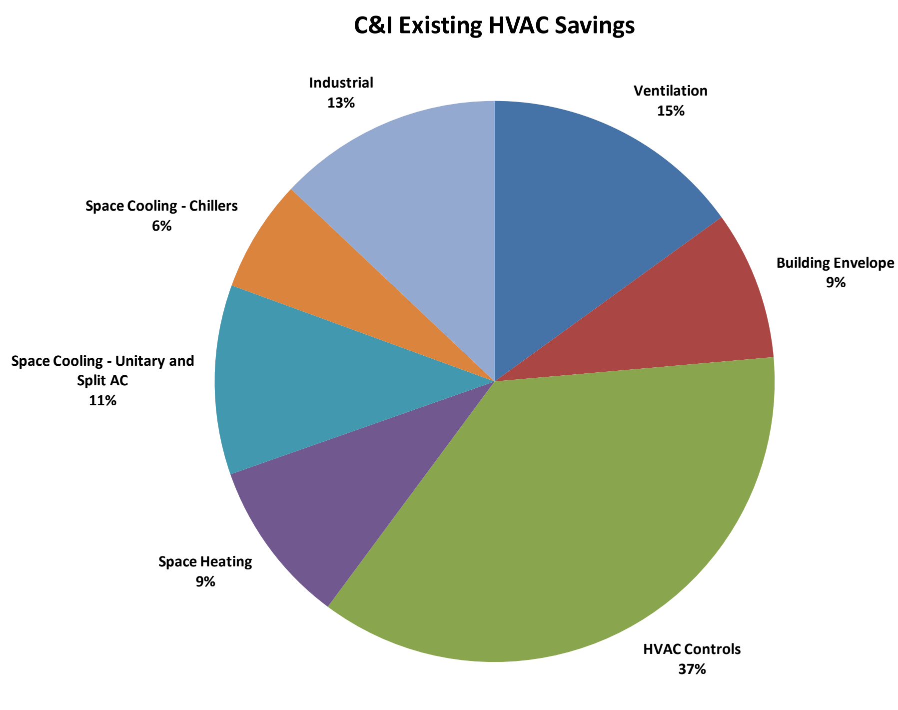
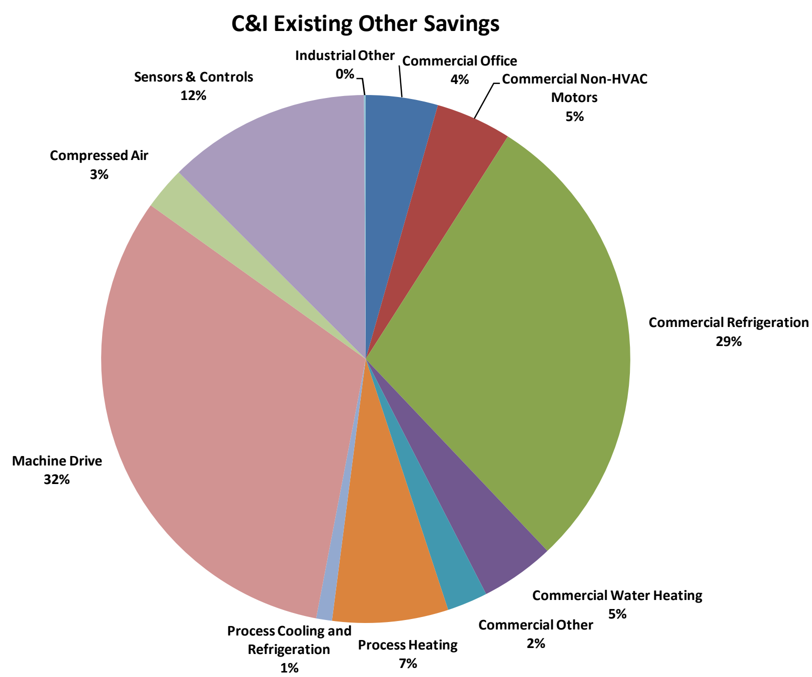


Exhibit IV-13 presents a breakdown of the potential savings from the Other measure category in the C&I sector. The end-use categories that are not labeled as "Commercial" are industrial measures. The Other category includes potential savings associated with efficient process, refrigeration and motor measures. These measures are generally supported by the existing PSNH CORE Programs.

**Exhibit IV-13: C&I Existing Potential Other Savings**




<u>Program Design and Implementation</u>

The Market Potential Scenario represents a transition from the existing CORE Program portfolio and participation levels to a programmatic expansion over a five-year period that is designed to realize the annualized potential savings in 2015. The program expansion incorporates the following key elements:

- Customer incentives for all non-lighting measures in existing buildings that are approximately equal to or greater than 50 percent of the incremental measure cost.
- Expanded implementation of non-lighting measures in existing buildings that ramps up from current levels in order to achieve the market potential savings in 2015.
- The addition of a retro-commissioning services component to the Large C&I Retrofit program.
- The expansion of HVAC and Other measure support in the Small Business Energy Solutions program.

The projected program expenditures required to achieve the savings potential are presented in Exhibit IV-14.

### Exhibit IV-14: C&I Market Potential Scenario Program Expenditures

| Program | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|
| SmartStart | $ 50,000 | $ 50,000 | $ 50,780 | $ 51,572 | $ 52,377 | $ 53,194 |
| Customer Partnerships | $ 30,000 | $ 30,000 | $ 30,468 | $ 30,943 | $ 31,426 | $ 31,916 |
| New Equipment & Construction | $ 1,958,884 | $ 2,014,989 | $ 2,046,423 | $ 2,078,347 | $ 2,110,769 | $ 2,143,697 |
| Large C&I Retrofit | $ 2,466,743 | $ 3,559,620 | $ 5,302,779 | $ 6,928,998 | $ 8,593,639 | $ 10,308,530 |
| Small Business Energy Solutions | $ 2,321,641 | $ 2,524,561 | $ 2,770,030 | $ 2,970,971 | $ 3,177,508 | $ 3,389,765 |
| RFP Program | $ 507,859 | $ 766,384 | $ 783,760 | $ 1,081,138 | $ 1,387,603 | $ 1,703,366 |
| Education | $ 157,507 | $ 157,507 | $ 159,964 | $ 162,460 | $ 164,994 | $ 167,568 |
| **C&I Total** | **$ 7,492,634** | **$ 9,103,061** | **$ 11,144,204** | **$ 13,304,429** | **$ 15,518,315** | **$ 17,798,036** |

## Residential Sector Potential Analysis and Results

Analysis of Remaining Potential

The GDS Study produced state-wide estimates of Demand Side Potential savings from electric and non-electric energy efficiency measures. PSNH's potential savings estimates apply to electric-savings measures installed in customers' facilities within PSNH's service territory. The GDS electric savings results were therefore reduced by a factor derived from PSNH's percent of New Hampshire forecasted sales by customer sector. The Residential factor is 72 percent.

The GDS Obtainable Potential results for the Residential sector were annualized as described in Section A.1. The Obtainable Potential savings, annualized and adjusted for PSNH's service territory, were analyzed in order to identify the major measure/end-use categories in which the estimated potential savings significantly exceeds PSNH's program savings goals reported in the *2010 CORE New Hampshire Energy Programs* plan filed with the Commission on September 30, 2009.

Exhibit IV-15 presents a comparison of the GDS Obtainable Potential annualized MWh savings to PSNH's savings projection reported in the 2010 program plans. This comparison indicates that in all measure categories the current level of CORE Program savings is substantially less than the Obtainable Potential savings and therefore that the remaining potential is significant. Also, in contrast to the C&I sector (see Exhibit IV-15), the projected Market Potential is much less than the Obtainable Potential savings. The reasons for this difference were briefly discussed in Section A.1 Market Potential Methodology, Review and Revision of Technical Assumptions and are discussed in more detail in the following section.

**Exhibit IV-15: Residential Comparison of Obtainable Potential to Current Savings**
(Annualized MWh)

| Measure Category | Obtainable Potential | 2010 CORE Savings | 2015 Market Potential |
|---|---|---|---|
| New Construction | 1,766 | 1,121 | 2,823 |
| Lighting | 27,447 | 11,779 | 2,421 |
| Refrigerator Removal | 5,280 | - | 1,954 |
| ES Appliances | 5,437 | 1,841 | 2,202 |
| HVAC | 2,537 | 147 | 1,141 |
| Domestic Hot Water | 1,170 | - | 1,170 |
| Weatherization | 1,220 | 226 | 619 |
| Other | 5,404 | 71 | 1,223 |
| Total Residential | 50,261 | 15,185 | 13,551 |

Identification of Priority Measures and Review and Revision of Technical Assumptions

The "bottom-up" approach taken by GDS to the analysis of Residential potential and the relative homogeneity of usage among households compared to C&I customers allows for a more disaggregated measure-specific review of generic savings assumptions and penetration rates. The magnitude of the Obtainable Potential savings for a given measure depends on a number of factors that determine the average annual kWh savings per measure and the number of measures that can potentially be installed in any year (annual penetration limit). The measures that account for a significant portion of the potential savings were assigned a high priority for technical review. The results of the technical review are discussed as follows by measure category. The effects of the revisions on potential savings are summarized in Exhibit IV-16.

**Exhibit IV-16: Residential Obtainable Potential Revisions**
(Annualized MWh)

| Measure Category | Obtainable Potential | Adjusted Potential | 2010 CORE Savings | 2015 Market Potential |
|---|---|---|---|---|
| New Construction | 1,766 | 2,823 | 1,121 | 2,823 |
| Lighting | 27,447 | 5,676 | 11,779 | 2,421 |
| Refrigerator Removal | 5,280 | 1,954 | - | 1,954 |
| ES Appliances | 5,437 | 2,228 | 1,841 | 2,202 |
| HVAC | 2,537 | 1,811 | 147 | 1,141 |
| Domestic Hot Water | 1,170 | 1,170 | - | 1,170 |
| Weatherization | 1,220 | 640 | 226 | 619 |
| Other | 5,404 | 2,170 | 71 | 1,223 |
| Total Residential | 50,261 | 18,471 | 15,185 | 13,551 |

New Construction

The Market Potential savings is based on a significant increase in the annual level of Energy Star Homes program participation consistent with the Obtainable Potential annual penetration limit as well as the continued installation of geothermal and air-source heat pumps in new homes. The latter component accounts for the increase in the adjusted potential savings because the GDS estimated potential savings from ground source heat pumps is substantially lower than current program savings estimates.

Lighting

Compact Fluorescent Lamps account for 83 percent of the Obtainable Potential savings from lighting measures. The EISA sets new performance standards for many common light bulbs. The new standards will be phased in over a two-year period, beginning January 1, 2012 and ending January 1, 2014. The GDS analysis of Obtainable Potential did not account for the new lighting standards. The savings potential is based on the assumption that CFLs replace standard incandescent bulbs. Standard incandescent bulbs do not comply with the new standards. Therefore, once the new standards take effect, the baseline technology will be either CFLs or advanced incandescent lamps that comply with the standards. While CFLs are significantly more efficient than the minimum efficiency prescribed by EISA, which is the expected efficiency of the advanced incandescent bulbs, the incremental cost of the CFLs over the advanced incandescent products is not likely to be sufficient to warrant a rebate. The Market Potential Scenario therefore reflects a transition from current CFL incentives to no incentives in 2014 for CFLs purchased through the retail channel of the Energy Star Lighting program. Incentives for fixtures (retail and catalog) and lamps available through the catalog are maintained on the assumption that some compliant products and products outside the scope of the EISA standards will continue to be promoted through the program.

Incentives and savings for all catalog products and fixtures sold through retail outlets were retained at current levels, with two exceptions. The annual penetration of Retail LED fixtures was increased to transition from current levels to the level assumed in the Obtainable Potential calculation. Also, the penetration of outdoor lighting controls, currently available through the catalog, was increased substantially, but the Obtainable Potential market penetration was considered to be too high to achieve by 2015, which accounts for the difference between the Adjusted Potential and the Market Potential in Exhibit IV-16.

Refrigerator Removal

Substantial savings may be achieved by the removal of operating second refrigerators and freezers if they are not replaced. These appliances tend to be older inefficient models and their use is somewhat discretionary. Technical review of the GDS assumptions indicated that the average annual savings per appliance, the maximum annual penetration and the cost of removal were not in line with actual program experience in Connecticut and New Hampshire.

The Connecticut Light and Power Company and The United Illuminating Company commissioned an impact, process and market evaluation of the Connecticut Appliance

Retirement Program. The study estimated an average savings per appliance and penetration limit that are substantially lower than the GDS assumptions. The Obtainable Potential savings were revised accordingly. The assumed average cost of removal was also revised to be consistent with New Hampshire implementation contractor costs.

Energy Star Appliances

The GDS estimate of Obtainable Potential includes significant savings from the purchase of Energy Star clothes washers, refrigerators and dish washers. PSNH's 2010 planned participation level is right in line with the GDS obtainable annual penetration limit for Energy Star clothes washers, but the GDS assumption for average annual kWh savings per unit is more than twice the average savings value employed by PSNH for program planning. It appears that the original GDS savings assumption, similar in magnitude to PSNH's value, was altered in the modeling process. Therefore the total potential savings from Energy Star clothes washers was revised by replacing the GDS savings per unit with PSNH's assumption.

While increased penetration of Energy Star qualified refrigerators and dish washers can make a significant contribution to potential savings, unlike clothes washers, their incremental cost is virtually zero or sufficiently low to be inconsequential as a factor in the purchasing decision. The Market Potential Scenario provides for marketing efforts to inform customers of these energy savings opportunities, but it is difficult to quantify the impact of marketing on penetration levels with the precision required to establish program savings goals. Therefore the Market Potential Scenario and the Adjusted Potential do not include potential savings from the increased market penetration of these appliances. They do, however, include projected savings from the replacement of refrigerators through the Home Energy Assistance program.

HVAC

PSNH's planned 2010 participation level is right in line with the GDS obtainable annual penetration limit for Energy Star room air conditioners, but the GDS assumption for average annual kWh savings is significantly higher than the average savings value employed by PSNH for program planning. Therefore, the amount of potential savings was revised to be consistent with the current planning assumption. Also, the Adjusted Potential savings exclude savings from Energy Star dehumidifiers because the incremental cost of Energy Star dehumidifiers is low, as in the case of Energy Star refrigerators and dishwashers. The difference between the Adjusted Potential and the Market Potential savings is accounted for by the efficient furnace fan measure. The Obtainable Potential market penetration was considered to be too high to achieve by 2015, so the 2015 penetration was reduced in the Market Potential Scenario.

Weatherization

In addition to standard weatherization measures, the GDS Obtainable Potential estimate includes savings from Energy Star windows, but, as in the case of other Energy Star qualified equipment, the incremental cost of efficient windows is not likely to be a significant factor in the purchasing decision. The Adjusted Potential therefore does not include savings from this measure.

Other

The Other measure category includes miscellaneous measures, such as phantom power controls, Energy Star office equipment, and televisions. The Adjusted Potential savings reflect a revision to the average savings and market penetration assumptions for phantom power controls, and the elimination of savings from Energy Star office equipment and televisions, due to low or no incremental cost to the customer associated with such measures.

As a general matter, the revisions to the Obtainable Potential savings introduce an element of conservatism into the Market Potential projections that is appropriate given the likelihood of increasing standards of efficiency for all types of equipment, a trend that is not accounted for by the GDS Study.

Program Design and Implementation

The Market Potential Scenario represents a transition from the existing CORE Program portfolio and participation levels to a programmatic expansion over a five-year period that is designed to realize the annualized potential savings in 2015. Exhibit IV-17 presents the modeled correspondence between the current programs and the priority measures indentified by GDS which make a substantial contribution to the Obtainable Potential savings. This correspondence is based on modeling assumptions regarding the program delivery channel for each priority measure. For example, Smart Power strips are currently offered through the Lighting Catalog program and HVAC and DHW measures would be delivered via the in-home services program.

**Exhibit IV-17 Residential Programs and Priority Measures**

| Program | New Construction | Lighting | ES Appliances | Refrigerator Removal | HVAC | Domestic Hot Water | Weatherization | Other |
|---|---|---|---|---|---|---|---|---|
| EnergyStar Homes | Eff. Design | | | | | | | |
| ES Homes - Geothermal | Eff. Design | | | | | | | |
| EnergyStar Lighting | | Outdoor<br>LEDs | | | | | | Smart Power |
| EnergyStar Appliances | | | Clothes Washers | Refr. Removal | Room AC | | | |
| NH Home Perf. w/ Energy Star | | | | | Thermostats<br>Fans<br>Heat Pumps<br>Duct sealing | DHW | Weatherization | |

The projected program expenditures required to achieve the savings potential are presented in Exhibit IV-18.

**Exhibit IV-18: Residential Market Potential Scenario Program Expenditures**

| Program | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|
| Home Energy Assistance | $ 2,136,334 | $ 4,005,466 | $ 4,674,877 | $ 5,117,641 | $ 5,573,082 | $ 6,041,487 |
| NH Home Perf. w/ Energy Star | $ 1,620,080 | $ 1,797,458 | $ 2,152,128 | $ 2,556,646 | $ 2,973,262 | $ 3,418,847 |
| EnergyStar Homes | $ 945,047 | $ 1,573,368 | $ 2,108,984 | $ 3,210,110 | $ 3,874,458 | $ 4,359,667 |
| EnergyStar Appliances | $ 630,031 | $ 1,029,290 | $ 1,187,985 | $ 1,523,326 | $ 1,893,732 | $ 2,275,324 |
| EnergyStar Lighting | $ 945,047 | $ 1,026,590 | $ 1,092,334 | $ 1,143,701 | $ 1,121,297 | $ 1,233,789 |
| HeatSMART | $ - | $ - | $ - | $ - | $ - | $ - |
| ES Homes - Geothermal | $ 360,018 | $ 408,112 | $ 414,479 | $ 420,945 | $ 427,512 | $ 434,181 |
| U-S: Other | $ - | $ - | $ 40,961 | $ 99,377 | $ 234,715 | $ 238,377 |
| **Residential Total** | **$ 6,636,557** | **$ 9,840,285** | **$ 11,671,748** | **$ 14,071,746** | **$ 16,098,057** | **$ 18,001,673** |

## C. Economic Analysis of Energy Efficiency Program Potential

An economic analysis of the Market Potential Scenario was conducted utilizing the Total Resource Cost (TRC) test of program cost-effectiveness. This section includes a description of the methodology along with a presentation of the results.

### C.1. Economic Analysis Methodology

<u>Total Resource Cost Test</u>

The economic analysis utilized the TRC test to evaluate the cost-effectiveness of the Market Potential Scenario. The TRC test has been approved by the Commission as the appropriate methodology to conduct benefit-cost analysis of demand side resource options. The key elements of the methodology are summarized as follows:

- The TRC test is a comparison of the present value of energy efficiency program benefits and costs over the expected life of the installed measures.
- The economic costs include all incremental program implementation costs:
    - Incremental measure cost, including participating customer costs
    - EE program expenditures, including program administration, marketing and evaluation cost.
- The economic benefits include all incremental program savings:
    - Avoided cost of electric generation energy and capacity, including environmental compliance costs.
    - Avoided cost of transmission and distribution capacity.
    - Avoided cost of end-use fossil fuel consumption.
    - Avoided cost of other resource consumption (e.g. water and sewerage costs).

<u>Avoided Costs</u>

The avoided costs employed in the economic analysis were developed through the efforts of the 2009 Avoided Energy Supply Cost (AESC) Study Group, comprised of electric utilities, gas utilities and other efficiency program administrators, non-utility parties and their consultants, for the use by New England energy efficiency program administrators in benefit-cost analysis of demand side resources. The AESC Study Group employed an independent consultant to develop "projections of marginal energy supply costs which will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England."

The background, methodology, and results of the 2009 AESC Study are documented in the August 21, 2009 report *Avoided Energy Supply Costs in New England: 2009 Report*. The utilization of the avoided energy supply costs and avoided transmission and distribution costs in the present analysis is consistent with the analysis reported in the document *2010 CORE New Hampshire Energy Efficiency Programs* filed with the Commission on September 30, 2009.

## C.2. Economic Analysis Results

The results of the TRC Test are summarized in Exhibit IV-19. The Base Case results are also presented for comparison.

**Exhibit IV-19: Total Resource Cost Test Results Summary**

| EE Program Scenario | NPV EE Program Cost | NPV EE TRC Cost | NPV Avoided Electric Cost | NPV TRC Benefit | Net TRC | TRC B/C |
|---|---|---|---|---|---|---|
| Market Potential | $126,945,408 | $199,510,160 | $313,236,907 | $404,471,604 | $204,961,443 | 2.03 |
| Base Case | $ 68,370,827 | $112,485,083 | $182,917,356 | $223,339,584 | $110,854,501 | 1.99 |

The results are defined as follows:

**NPV EE Program Cost** is the present value, over the period 2011-2015, of the projected energy efficiency program expenditures reported in Exhibit IV-7.

**NPV EE TRC Cost** is the present value, over the period 2011-2015, of the energy efficiency program expenditures plus the projected incremental costs incurred by participating customers to install the energy efficiency measures.

**NPV Avoided Electric Cost** is the present value, over the expected useful life of the energy efficiency measures, of the projected electric energy and capacity savings resulting from the energy efficiency investments.

**NPV TRC Benefit** is the present value, over the expected useful life of the energy efficiency measures, of all resource savings, including avoided electric costs, avoided fossil fuel costs, and other resource savings resulting from the energy efficiency investments.

**Net TRC** is the difference between the NPV TRC Benefit and the NPV EE TRC Cost.

**TRC B/C** is the ratio of the NPV TRC Benefit and the NPV EE TRC Cost.

The results indicate that the lifetime savings from energy efficiency investments over the five year planning period amount to over $200M and $110M, respectively, for the Market Potential and Base Case scenarios. The cumulative Net TRC for each scenario is presented in Exhibits IV-20 and IV-21, in order to illustrate how the cumulative net present value of the energy efficiency investments evolves over the expected life of the measure savings. In the charts below, after eight years the costs become negative, representing a savings.

**Exhibit IV-20: Cumulative Net TRC – Market Potential Scenario**

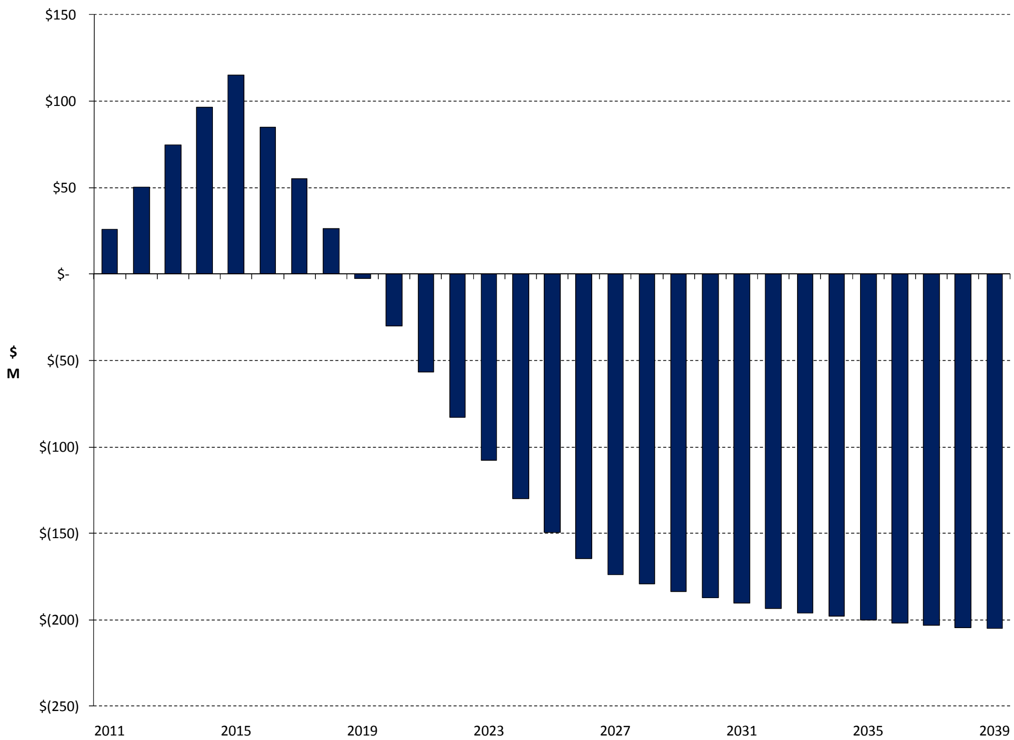
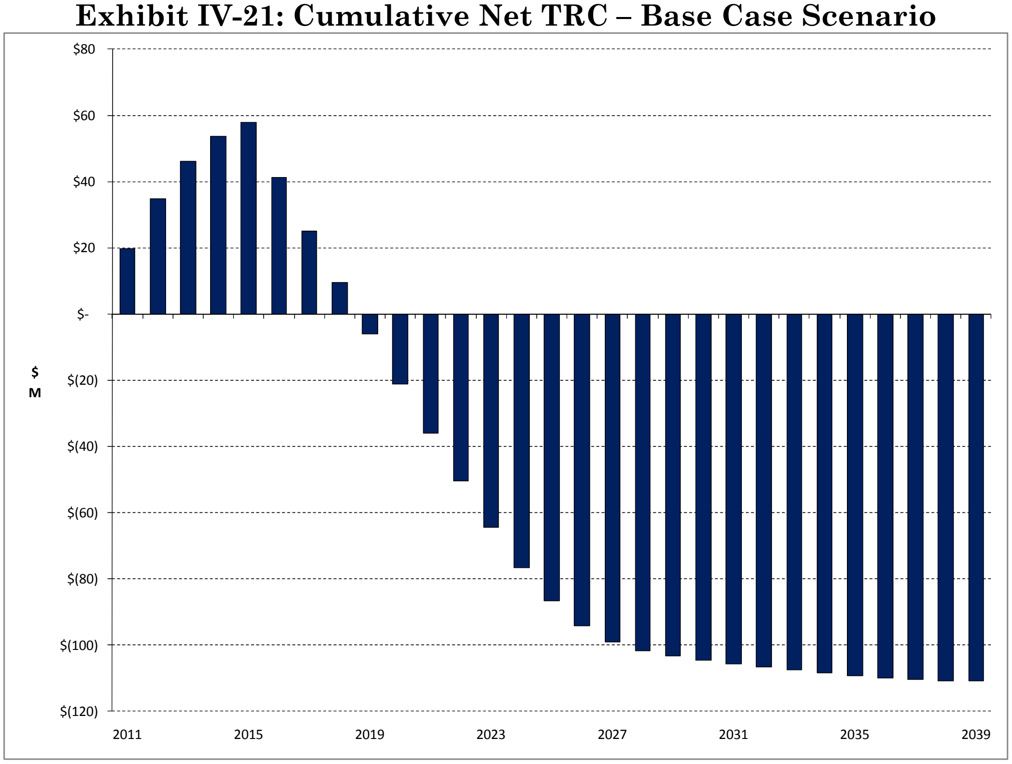



**Exhibit IV-21: Cumulative Net TRC – Base Case Scenario**



## D. Sensitivity Analysis

In Order No. 24,945 the Commission directed PSNH to conduct a sensitivity analysis of the Total Resource Cost test using a reasonable forecast of the full cost of $CO_2$ using climate sustainability targets for $CO_2$ and to examine the impact of the resulting higher avoided costs on Obtainable Potential savings. Also, as directed by the Commission, PSNH based this analysis on the most recent avoided energy supply cost study for New England (i.e. 2009 AESC Study, August 21, 2009). It should be noted that the prices shown here may differ from more recent forecasts used in other analyses elsewhere in this document.

An environmental externality is the value of an environmental impact associated with the use of a product or service, such as electricity, that is not reflected in price of that product. The derivation of the $CO_2$ externality values, described in the 2009 AESC Study report cited above, was based on the difference between an assumed long-run marginal abatement cost of $80 per ton of $CO_2$, necessary to stabilize global carbon emissions at a sustainable level ("sustainability target"), and the projected market price of $CO_2$ allowances internalized in the wholesale price of electricity. The externality values are presented in Exhibit IV-22.

**Exhibit IV-22: $CO_2$ Externality Calculations ($2009)**

| | Sustainability Target ($/short ton) | Allowance Price ($/short ton) | Externality ($/short ton) |
|---|---|---|---|
| | a | b | c=a-b |
| **2009** | $80 | $3.85 | **$76.15** |
| **2010** | $80 | $3.91 | **$76.09** |
| **2011** | $80 | $4.02 | **$75.98** |
| **2012** | $80 | $4.00 | **$76.00** |
| **2013** | $80 | $15.63 | **$64.37** |
| **2014** | $80 | $18.03 | **$61.97** |
| **2015** | $80 | $20.32 | **$59.68** |
| **2016** | $80 | $22.72 | **$57.28** |
| **2017** | $80 | $25.01 | **$54.99** |
| **2018** | $80 | $27.41 | **$52.59** |
| **2019** | $80 | $29.70 | **$50.30** |
| **2020** | $80 | $32.10 | **$47.90** |
| **2021** | $80 | $32.74 | **$47.26** |
| **2022** | $80 | $33.40 | **$46.60** |
| **2023** | $80 | $34.06 | **$45.94** |
| **2024** | $80 | $34.75 | **$45.25** |

Source: *Avoided Energy Supply Costs in New England: 2009 Report* (Exhibit 6-56)

The impact of the assumed externalities on the avoided energy costs is presented in Exhibit IV-23.

**Exhibit IV-23: $CO_2$ Externality Impact on Avoided Costs ($2009)**

| Year | Winter Peak Energy | Winter Off-Peak Energy | Summer Peak Energy | Summer Off-Peak Energy |
|---|---|---|---|---|
| | ($/kWh) | ($/kWh) | ($/kWh) | ($/kWh) |
| 2010 | 0.039 | 0.039 | 0.038 | 0.041 |
| 2011 | 0.039 | 0.039 | 0.038 | 0.041 |
| 2012 | 0.039 | 0.039 | 0.038 | 0.041 |
| 2013 | 0.033 | 0.033 | 0.032 | 0.034 |
| 2014 | 0.032 | 0.032 | 0.031 | 0.033 |
| 2015 | 0.030 | 0.031 | 0.030 | 0.032 |
| 2016 | 0.029 | 0.030 | 0.028 | 0.031 |
| 2017 | 0.028 | 0.028 | 0.027 | 0.029 |
| 2018 | 0.027 | 0.027 | 0.026 | 0.028 |
| 2019 | 0.026 | 0.026 | 0.025 | 0.027 |
| 2020 | 0.024 | 0.025 | 0.024 | 0.026 |
| 2021 | 0.023 | 0.024 | 0.023 | 0.024 |
| 2022 | 0.022 | 0.022 | 0.021 | 0.023 |
| 2023 | 0.021 | 0.021 | 0.020 | 0.022 |
| 2024 | 0.020 | 0.020 | 0.019 | 0.021 |

On a levelized basis, the addition of the $CO_2$ externality can increase the avoided electric cost by 10 to 50 percent, depending on the load shape and life of the energy efficiency measure. In terms of the GDS analysis of Obtainable Potential, an increase in the avoided cost could have two effects. One possible effect would be to include measure savings in the Maximum Achievable Cost-Effective (MACE) Potential that are excluded at a lower avoided cost. The other possible effect is to include cost-effective measure savings in the Obtainable Potential that is excluded at a lower avoided cost. The GDS calculation of Obtainable Potential savings was based on a percent of the MACE potential savings, depending on the levelized cost (LC) of the measure. The basic parameters of the calculations are presented in Exhibit IV-18.

GDS employed the assumption that the Industrial Sector Obtainable Potential savings is 48 percent of the MACE potential savings. All Industrial measures were determined to be cost-effective, but a supply-curve analysis was not utilized in this sector because the savings potential was modeled at the end-use level instead of the more detailed measure level of disaggregation.

A rough midpoint of 30 percent within the range of increase in the avoided cost was selected to evaluate the impact on the Obtainable Potential savings. The GDS supply curves were examined to identify the measures with a levelized cost between $0.07 (OP Threshold 1) and $0.09(≅$0.07 x 1.3), based on the assumption that the full cost of implementation of the sustainability target is internalized in the avoided cost, in which case the threshold payback to the customer would be translated up the supply curve to a proportionately higher levelized measure cost. The Obtainable Potential savings of cost-effective measures that fall within this interval along the supply curve would be doubled, because they would move below Threshold 1 (see Exhibit IV-24).

**Exhibit IV-24: GDS Obtainable Potential Calculation**

| Sector | OP LC Threshold 1 ($/kWh) | OP LC Threshold 2 ($/kWh) | OP % of MACE LC< a | OP % of MACE a<LC<b |
|---|---|---|---|---|
| | (a) | (b) | | |
| Residential | 0.07 | 0.50 | 73% | 37% |
| Commercial | 0.07 | 2.00 | 48% | 24% |
| Industrial | NA | NA | 48% | NA |

If, on the other hand, the full avoided cost of sustainability were not internalized in the market price of electricity, then the Obtainable Potential savings would not increase because the payback to the customer would be unchanged.

It is also possible that the TRC benefit-cost ratio (BCR) of certain measures that are excluded from the MACE potential would be included at the higher avoided cost that includes the $CO_2$ externality. The GDS BCR data were reviewed to identify measures with a BCR between 1.0 and .8 (≅1.0/1.3). If a measure is cost-effective at the higher avoided cost, then the Obtainable Potential will be increased as a percent of the MACE according to the threshold levelized measure cost (LC) in Exhibit IV-24. Measures with a levelized cost higher than Threshold 2 were not included in the GDS estimate of Obtainable Potential because of the long payback.

The results of the sensitivity analysis are presented in Exhibit IV-25. The table categorizes the measures as follows:

- Measures that are cost-effective (included in MACE) without inclusion of the externality, but which have increased Obtainable Potential savings with inclusion of the externality because the levelized measure cost falls between $0.07 and $0.09.

- Measures that are not cost-effective (excluded from MACE) without inclusion of the externality, but which are cost-effective with inclusion of the externality and which have increased Obtainable Potential savings with inclusion of the externality because the levelized measure cost falls between $0.07 and $0.09.

- Measures that are not cost-effective (excluded from MACE) without inclusion of the externality, but which are cost-effective with inclusion of the externality and which have the lower level of Obtainable Potential savings with inclusion of the externality because the levelized measure cost exceeds $0.09.

The inclusion of the additional savings from these measures has the effect of increasing the Obtainable Potential by 2.2 percent in the Residential Sector and by 3.7 percent in the Commercial Sector. If the externality is not internalized, these effects on OP would be reduced, respectively, to 0 percent and 1.6 percent, based on the contributions of the measures described in the second and third bullets above.

**Exhibit IV-25: Sensitivity Analysis Results**

| Measure | MACE | < OP T1 |
|---|---|---|
| **Residential** | | |
| Efficient Furnace Fan (Non-Electric Furnace) | NE | E |
| Integrated Building Design - Better (Oil Heat) | NE | E |
| High Efficiency Heat Pump (Tier 2) | NE | E |
| Programmable Thermostats (Oil Heat + Central Air) | NE | E |
| Integrated Building Design - Better (Electric Heat) | NE | E |
| **Commercial** | | |
| Evaporator Fan Motor Controls | NE | E |
| LED Exit Sign | NE | E |
| Fan Motor, 5hp, 1800rpm, 90.4% | NE | E |
| Chiller Tune Up/Diagnostics - 300 ton | NE | E |
| Variable Refrigerant Volume/Flow | NE | E |
| HE Combination Oven | NE | E |
| Energy Efficient Pool Pump with controls | NE | E |
| Point of Use Water Heater | E | N |
| LED lighting retrofits in refrigeration end-uses | E | E |

NE - Measure is cost-effective without CO2 externality.
E - Externality required to be cost-effective or for LC<OP Threshold 1.
N - LC>OP Threshold 1 with externality.

## E. Demand Response & Load Management Programs

The intent of this section is to review PSNH's current demand response and load management programs and to present an analysis of several new options PSNH has examined for possible expansion of its program offerings. In addition, the ISO-New England administered energy efficiency and demand response programs that are eligible for capacity payments under the pending Forward Capacity Market are reviewed along with energy efficiency programs offered by competitive market providers.

## E.1. PSNH's Current Programs

Beyond the CORE Programs, PSNH has several demand-side management programs in place that are used to help reduce system demands at periods of high use, high costs, or when there is an energy shortage. The PeakSmart and HEATSMART programs described below operate on a system-wide basis and are not designed to target in a particular geographic area or individual circuit.

**PeakSmart (formerly Voluntary Interruption Program)**

PSNH's PeakSmart Program (Rate VIP) is available during the high-load months of June through September each year. The objective of this interruptible load program is to establish a mechanism whereby PSNH can notify large commercial and industrial customers when the regional demand for electricity threatens to reach a peak or during times of high real-time New Hampshire zonal prices as determined by ISO-New England, and request that they curtail load. It is open to larger customers (Rates GV and LG) who have hourly metering available to estimate the amount of load curtailment when interruptions occur. This estimate will be based on hourly meter readings adjusted to account for normal load shapes. Participation and interruption is voluntary, with payments based on actual performance. Customers must be willing to interrupt 100 kW or 10 percent of their load, whichever is greater. During the last several years, PSNH has been able to achieve approximately 20 megawatts of voluntary participation among its large customers. In response to the changing demand response market, PSNH introduced PeakSmartPlus in April 2008, which is discussed below. While PeakSmart is still available today, the program does not have enrolled customers at the present moment. Customers have opted to enroll or are investigating to enroll in the ISO-New England's Forward Capacity Market.

**PeakSmartPlus**

In April 2008, PSNH implemented PeakSmartPlus based on ISO-New England's 30 Minute Real-Time Demand Response Program under the Forward Capacity Market (FCM) Transition Period. The program ended on May 31, 2010, coincident with the end of the FCM Transition Period. At the end of the program, PSNH had enrolled 25 customers with 10.679 MW of curtailable load.

Customers were compensated for the capacity they provided through load reductions or operation of their emergency generation. Once enrolled in the program and prior to the calling of a curtailment event by ISO-New England, program participants were compensated based on their committed load reduction (or emergency generator capacity). After a curtailment event, participant payments were based on actual performance during curtailment. Payments were based on a fixed fee schedule established for the FCM Transition Period which ran from December 1, 2006 through May 31, 2010. During the Transition Period, the ISO-New England recognized all qualified assets and compensated the assets in accordance with a published fee schedule.

Beginning June 1, 2010, the start of FCM, demand response assets must have obtained a capacity supply obligation via a Forward Capacity Auction (FCA) in order to receive payment and the amount paid for demand reductions will vary depending on the results of the auction. PSNH introduced PeakSmartPlus in April 2008, although not as part of the FCAs due to timing requirements imposed by ISO-New England. As a result, neither the current funding mechanism available during the Transition Period, nor its successor mechanism, the FCA, will be available to support PeakSmartPlus participation beyond May 31, 2010.

In Docket No. DE 09-158, PSNH proposed changes and possible sources of funding to continue to offer PeakSmartPlus beyond May 31, 2010. The Commission, in Order No. 25,059 dated December 31, 2009, determined that "viable market options exist for PSNH's commercial and industrial customers to continue DR [demand response] participation without the need to tap into CORE Program funds [energy efficiency funds which were one of the possible sources of funding proposed]." As required by the Order, PSNH assisted its PeakSmartPlus customers to transition into the FCM, and continues to offer its voluntary interruption program, PeakSmart.

**HEATSMART Program**

The HEATSMART program offers residential and small commercial customers a discounted delivery rate in exchange for allowing PSNH to curtail their usage using a radio controlled signal sent to equipment installed at the customer's premises. HEATSMART is primarily designed to help control winter peaking demands, and is most often initiated by ISO-New England Operating Procedure No. 4 (Action During a Capacity Deficiency), Action 10, but can also be initiated by PSNH's Dispatcher. This program is available 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. PSNH has over 3,600 residential customers and 75 commercial customers enrolled in the HEATSMART program. PSNH estimates there are 80 MW of connected HEATSMART load – approximately 8 MW coincident with the New England summer system peak (22 MW winter peak).

In exchange for the lower HEATSMART rate, PSNH can interrupt the HEATSMART 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.

## E.2. Potential Program Offerings

PSNH has examined a number of program concepts for possible inclusion in an expanded set of program offerings. The following sections highlight the results of the Company's review.

**Interruptible Residential Service**

The market for interruptible equipment in the residential sector continues to expand with new products. The equipment is designed to interrupt targeted loads such as air conditioners, water heaters, and pool pumps during periods of peak electrical demand. Similar to PSNH's HEATSMART program, a radio signal is sent to a device at the customer's home that can raise and lower thermostats or cycle equipment on and off.

Newer technologies, such as programmable thermostats, can be controlled by a utility dispatcher to cycle central air conditioning units, raise the temperature one to two degrees per hour for a set number of hours, or lower the temperature of the home in the morning in preparation for an anticipated afternoon interruption. In some cases these devices are web-enabled and the homeowner has the ability to monitor and control thermostats and other equipment remotely from any internet connection.

Two utilities which have recently started utilizing these interruptible technologies for residential customers include Kansas City Power & Light and Florida Power & Light. Both companies are using these interruptible technologies to help reduce energy demand during summer peak periods. The infrastructure supporting these interruptible technologies is emerging rapidly and further evaluation is needed before undertaking a full-scale deployment in New Hampshire. Anecdotally, application of these devices may help in managing peak loads and increasing system efficiency, however, key unanswered questions need to be addressed such as; selection of a particular technology, the magnitude of the peak load reductions attainable for each end-use, customer reaction to the technology and service interruptions, and an assessment of the net benefits and costs.

**Thermal Energy Storage**

PSNH will continue to assess the potential use of off-peak cooling (OPC) systems that use thermal energy storage to provide air conditioning to buildings during peak times. Typically, ice is made at night and is melted during the day to provide cooling. Ice storage tanks, similar to hot water tanks, make and store ice at night during periods of low electrical system demand. The ice is then used to cool air during the day when demand for electric energy is high. In order to be cost-effective, systems in use today are typically 150 tons or larger (enough to cool 50,000 square feet of office space).

Benefits often cited with this technology include:

- Reduced capacity (kW) requirements during periods of peak electrical demand
- May reduce power plant emissions
- May result in lower cooling costs when service is provided under rate structures with significant price differentiation between on- and off-peak periods

Potential disadvantages include:

- System designs typically combine standard HVAC with a thermal storage system added on, and as a result, they tend to be more complicated and require more real estate resulting in higher initial costs and higher maintenance costs
- Total energy consumption may increase as a result of conversion to a thermal storage system
- Insufficient storage can lead to an inability to provide adequate cooling or a lack of savings on hot days

The complexities of thermal energy storage system design and operation require a site-specific analysis in order to properly evaluate the feasibility and cost-effectiveness of either conversion of an existing system or application to new construction and major renovation projects. There are many different system configurations and control strategies that can be applied in a given situation. The applicability and potential effectiveness of a system depends on the operational requirements of the facility and the capability of the building operation staff who will implement the control strategy. A detailed site-specific technical and economic analysis is essential to determine whether the system will provide sufficient savings to the customer to justify the investment and to reduce the risk of potential performance problems such as inadequate cooling of the facility.

While the GDS Study did not analyze the potential savings of thermal energy storage systems, PSNH recognizes the potential for cost-effective application of such systems in certain facilities, depending on the site-specific factors discussed above. PSNH currently provides for the payment of incentives for custom measures through the C&I RFP Program for Competitive and Economic Development. The expansion of the Commercial and Industrial programs incorporated into the Market Potential Scenario also includes a provision for site-specific analysis of thermal energy storage project proposals as a service to PSNH customers.

## E.3. Dynamic Retail Pricing

Dynamic retail pricing is addressed in Docket No. DE 06-061, Energy Policy Act of 2005. PSNH has filed testimony explaining its position with regard to dynamic retail pricing in that docket. There are no changes or updates to PSNH's earlier filed testimony on this issue.

## E.4. ISO-New England Programs

Starting on June 1, 2010, ISO-New England operates one real-time demand response program for assets qualified to participate in the Forward Capacity Market. Qualified assets under the Real-Time Demand Resource (RTDR) and the Real-Time Emergency Generation (RTEG) are required to respond within 30 minutes of ISO-New England's instructions to interrupt.

Participation in this program is available to individual customers or aggregated groups of customers including commercial and industrial customers capable of reducing their load by at least 100 kW upon notification. Customers enrolled in the ISO-New England load reduction program under the FCM are notified via the Demand Designated Entity (DDE) which is the primary path for communication of curtailment event data between ISO-New England, the DDE (third-party) providers and the individual customers. Upon notification of a demand response event by ISO-New England, each participating customer is responsible for compliance and demand reduction within 30-minutes from notification. Participants continue curtailing usage until they receive a dispatch instruction to restore usage. In addition to the demand response program- available under the FCM, ISO-New England administers two load response, priced-based programs:

- Real-Time Price-Response Program—involves voluntary load reductions by program participants that are eligible for payment when the forecasted hourly real-time LMP is greater than or equal to $100/MWh and ISO-New England has transmitted instructions that the eligibility period is open. Assets registered in the Real-Time Response Program are not eligible as a demand resource under the FCM.

- Day-Ahead Load Response Program (DALRP)—an optional program that allows a participant in any of the real-time programs to offer interruptions in increments of 100 kW or more concurrent with the Day-Ahead Energy Market. The participant is paid the day-ahead marginal price for interruptions. Any price deviations between the day-ahead market and the real-time market are reconciled. Assets participating in the Day-Ahead Load Response Program may be eligible to participate as a demand resource asset in the FCM. Assets that participate in both the Day-Ahead Load Response Program and the Real-Time Price Response Program are not eligible to participate in the FCM.

These programs will be effective through May 31, 2012.

The ISO-New England Real-Time Demand-Response and Real-Time Emergency Generation programs are activated during zonal or system wide capacity deficiencies in order to maintain or support system stability and reliability. ISO-New England has determined that the Demand-Response programs are classified as "Reliability Program" resources and this classification determines when the participating customers are notified under ISO-New England's Operating Procedure Number 4 (OP-4). OP-4 establishes criteria and guidelines for ISO-New England actions during capacity deficiencies and contains 11 action steps that can be implemented individually or in groups depending on the severity of the situation. The Real-Time Demand Response program is activated at Actions 2, and the Real-Time Emergency Generator resources are activated at Action 6.

According to ISO-New England, overall enrollment in ISO-New England programs has been increasing steadily. Data as of August 2, 2010, indicates that participant enrollment in the programs totaled 2,748 MW compared to 747 MW in July 2006 – an increase of 260 percent. ISO-New England published data for 2009 that indicates that the Real-Time Price-Response program experienced the most activity during that year with 72 days with interruptions in New Hampshire. The 30-Minute and Two-Hour Real-Time Demand-Response programs were activated on three days in 2009. All three of the activations were for audit purposes. Exhibits IV-26 and IV-27 show the ISO-New England demand response program enrollment data as of August 2, 2010 for each major demand or price-response program.

**Exhibit IV-26: ISO-New England Demand Response Program Enrollment**[11]

| Enrolled MWs (as of August 2, 2010) | | | | | |
|---|---|---|---|---|---|
| **Zone** | **Real-Time Demand Response** | **Real-Time Emergency Generation** | **On-Peak Demand Resource** | **Seasonal Peak Demand Resource** | **Total** |
| ME | 335.643 | 20.836 | 74.990 | 0.000 | 431.469 |
| NH | 49.708 | 32.228 | 52.529 | 0.000 | 134.465 |
| VT | 50.426 | 14.445 | 46.128 | 0.000 | 110.999 |
| CT | 311.206 | 319.530 | 73.378 | 235.724 | 939.838 |
| RI | 54.939 | 38.807 | 47.198 | 0.808 | 141.752 |
| SEMA | 71.940 | 48.920 | 64.899 | 3.366 | 189.125 |
| WCMA | 162.914 | 65.336 | 69.119 | 18.876 | 316.245 |
| NEMA | 92.235 | 89.356 | 109.564 | 0.000 | 291.155 |
| **Total** | **1,129.011** | **629.458** | **537.805** | **258.774** | **2,555.048** |

**Exhibit IV-27: ISO-New England Real-Time Price Response and Day-Ahead Load Response Program Enrollment**

| Enrolled MWs (as of August 2, 2010) | | |
|---|---|---|
| **Zone** | **RTPR** | **DALRP** |
| ME | 0.000 | 13.577 |
| NH | 4.450 | 6.400 |
| VT | 1.840 | 6.100 |
| CT | 2.250 | 47.093 |
| RI | 12.800 | 10.700 |
| SEMA | 8.400 | 13.000 |
| WCMA | 14.250 | 17.300 |
| NEMA | 19.100 | 15.700 |
| **Total** | **63.090** | **129.870** |

The load control impact that the ISO-New England programs have had thus far on New Hampshire retail customers is minimal when compared with the amount subscribed in critical-need areas such as Connecticut – especially Southwest Connecticut. The critical need for such programs in southern areas of New England has been substantial in order to mitigate the impact that peak load growth has had on areas lacking sufficient load transfer capability. It is important to note that the demand- and price-response programs play an important role in managing system reliability on the record peak-demand day. Absent such load interruptions, the peak demand in 2009 would have been hundreds of megawatts higher. PSNH anticipates that as customer awareness increases and third party demand response providers contact more customers, the amount of load under agreement will continually increase in 2010 and beyond.

[11] ISO-New England website, "Load Response Statistics as of 08-02-2010", http://www.iso-ne.com/genrtion_resrcs/dr/stats/enroll_sum/index.html

## E.5. Competitive Market Provider Programs

As described above, customers now have a variety of programs made available by ISO-New England to reduce load and/or reduce energy costs during times of high load or high energy costs. Under the programs, a third party or individual can arrange with ISO-New England to become an "Enrolling Participant" and will then be eligible to work with qualifying customers and enroll them in one of ISO-New England's demand response programs. It is important to note that a third party Enrolling Participant can enroll customers within PSNH's franchise area without PSNH's knowledge or involvement. Any customer who can make a commitment to reduce their power consumption by a minimum of 100 kW within 30 minutes of ISO-New England's request to curtail load can participate.

## F. Distributed Generation Options

Distributed Generation (DG) is small-scale generation interconnected to PSNH's distribution system at voltages of 46 kV or below. It includes customer-owned facilities, independent power producers, and PSNH's hydro-electric and combustion turbine facilities. DG facilities are operated interconnected to the power grid. Customer-owned facilities may be interconnected to run in parallel with the electric system supplying their own load as well as supplying power to the electric system, or in some cases, the entire output of the DG source is used to supply the electric system while the customers facility are served via the PSNH distribution system.

Large power plants have excellent economies of scale, but require an electric transmission grid to transmit power to customers. DG can be located in close proximity to load thereby eliminating the need to transmit the power through the transmission system. Locating appropriately sized DG at the distribution system level reduces system losses if located at or near the load and provides the potential to reduce the peak demand on equipment throughout the grid. Reducing local peak demand can delay upgrades to the infrastructure required to prevent overloads during peak load conditions. The reduction of losses and peak demand also can result in avoided Installed Capacity (ICAP) payments. PSNH has been able to utilize its hydro-electric and combustion turbine units effectively to benefit its distribution system. These distributed generation units are capable of supporting the system for various operating scenarios which can offset capital investments.

Certain DGs produce waste heat that can be used for space heating, water heating or other combined heat and power (CHP) uses. Using DG to provide both thermal and electrical energy is the most efficient way to utilize CHP type DG units. Some of PSNH's customers utilize this technology today. The enactment of the New Hampshire Renewable Portfolio Standard and the ISO-New England Forward Capacity Market may increase the use of DG on PSNH's system over the next few years. RPS subsidies may encourage PSNH's customers to consider utilizing green technologies when installing DG to meet their energy needs. Customers participating with renewable generation that qualifies as REC-eligible facilities may help PSNH to meet New Hampshire RPS requirements. Additionally, the ISO-New England Forward Capacity Market provides potential capacity subsidies to DG facilities.

Typically, the location of new customer-owned or merchant-owned DG on PSNH's distribution system is not disclosed to PSNH until such time as the customer or developer submits a request to interconnect with PSNH. There is an opportunity for the siting of facilities to be integrated into PSNH's planning process to optimize the impact on PSNH's distribution facilities. Based on cost per kilowatt (kW) of capacity, DG may be a cost effective method to address system-wide load growth and/or peak load requirements. If DG is sited in an area where it offsets load there is an additional overall distribution system benefit.

Renewable energy and distributed generation technologies are critical to the future energy portfolio of New Hampshire. Energy access, energy security, and environmental considerations, combined with increasing fossil fuel prices, are key drivers for accelerating the adoption of affordable distributed generation. The recent passage of RSA 374-G allows regulated electric utilities to develop and own up to 5 MW per site of distributed generation. This law allows PSNH to become more involved in DG around the state. Working within this framework, PSNH could develop a DG model that would provide distribution system benefit through both traditional and new generation technology.

PSNH has looked at locations on its distribution system where distributed generation would be beneficial to the system to postpone or delay investment in distribution upgrades. PSNH performed such an analysis of a generic small scale (up to 5 MW), renewable distributed generation project given PSNH's supply requirements and ability to add small scale renewable distributed. Section V.B.7 contains a generic economic analysis of a small scale distributed generation ground-mounted solar PV project.

As part of the PSNH restructuring agreement, PSNH is allowed to install distributed generation to reduce peak circuit loads on installed equipment and offset load driven capital projects. An example of distributed generation offsetting capital projects is the recent installation of a mobile generator on a circuit in the town of New Boston. There were two thermal issues on the circuit. The first issue involved parallel step transformers that were approaching long-term emergency ratings and the second issue involved loading the mainline conductor beyond its emergency rating. A 1.5 MW mobile generator was installed and interconnected in parallel with the circuit. PSNH also remotely monitored circuit loading as well as the mobile generator from the Electric System Control Center (ESCC). The ESCC remotely started the mobile generator as circuit loading approached predefined loading limits. The resulting generation offloaded the circuit step transformers and mainline conductors.

The New Boston mobile generation project was successful in meeting the goal of overcoming the technological hurdles of remote monitoring and remote starting a distributed generator to relieve thermal overloads on a distribution circuit. The project also proved the benefits of using this strategy to offset capital costs associated with projects justified by relieving short duration capacity peak problems. It is anticipated that PSNH will use the mobile generator for the next four years as a peak shaving strategy. It is also anticipated that this strategy could be used in various other locations throughout PSNH's system to assist in managing the costs associated with summer peak loads.

## G. Other Influences

### G.1. Legislature

In recent years the New Hampshire General Court has passed legislation related to the state's energy efficiency programs and available funding. Examples include:

- RSA 125-O:5-a established the Energy Efficiency and Sustainable Energy Board "…to promote and coordinate energy efficiency, demand response, and sustainable energy programs in the state."
- Senate Bill 228 (November 2005) and Senate Bill 300 (January 2010) temporarily reduced annual energy efficiency funding by $2.8 and $3.2 million respectively.
- RSA 374-F:4.VIII(e) which provides for limited use the System Benefits Charge for "Targeted conservation, energy efficiency, and load management programs and incentives that are part of a strategy to minimize distribution cost…" (Note: PSNH recently implemented a new Transmission and Distribution Procedure (TD-190) which incorporates into the distribution system planning process an examination of the potential for energy efficiency/demand response to delay infrastructure replacement expenditures.)
- House Bill 1377 (June 2010) permits utilities to establish loan programs for owners of residential and business property engaging in renewable energy and energy efficiency projects.
- Senate Bill 300 (January 2010) directs the Commission to contract an independent study of certain energy policy issues. The study is to include: (1) a comprehensive review and analysis of energy efficiency, conservation, demand response, and sustainable energy programs and initiatives in the state and to make recommendations for possible improvements; (2) the appropriate role of regulated energy utilities, providers of energy and energy efficiency, and others; (3) the effectiveness and sustainability of funds, and; (4) the policy changes that may be necessary to achieve the state's energy efficiency and sustainable energy goals. The final study is due November 1, 2011.

This list is not comprehensive, but serves to illustrate recent legislative actions. It is not the intent here to speculate regarding future legislative actions, but merely to point out that the plans presented here are subject to review and modification.

## G.2. Program Funding

Achieving the Base Case Scenario savings presented above in Section A.5 is dependent on continued System Benefits Charge funding at 1.8 mills/kWh. Achieving the Market Potential Scenario savings as discussed in Section B.2 would require significantly more funding. Exhibit IV-10 details the required program funding as well as the resulting energy savings for both the Base Case and the Market Potential scenarios. The table below highlights the annual incremental funding beyond that provided by the System Benefits Charge that will be needed in order to achieve the Market Potential Scenario savings:

**Exhibit IV-28: Incremental Funding To Achieve Market Potential Savings**

| Year | Expenditures | | | |
|---|---|---|---|---|
| | Base Case | Market Potential | Incremental $ | Incremental % |
| 2011 | $14,129,191 | $18,943,345 | $4,814,154 | 34% |
| 2012 | $14,349,606 | $22,815,951 | $8,466,345 | 59% |
| 2013 | $14,573,460 | $27,376,176 | $12,802,716 | 88% |
| 2014 | $14,800,806 | $31,616,372 | $16,815,566 | 114% |
| 2015 | $15,031,698 | $35,799,709 | $20,768,011 | 138% |

Were the System Benefits Charge to be the only funding mechanism, an increase of nearly 140 percent would be required by 2015. PSNH believes that funding should not be limited to the System Benefits Charge. Other sources such as the Regional Greenhouse Gas Initiative (RGGI) and the American Reinvestment and Recovery Act (ARRA) need to be an integral part of fully realizing the Market Potential Scenario savings. In addition, private loan capital could be an important element to the success of a significantly expanded set of program offerings.

## G.3. Codes and Standards

Updating and enforcing building energy codes and minimum efficiency standards for appliances have the potential for significant energy and capacity savings. While in general these activities are beyond PSNH's direct influence or control, PSNH is engaged with these efforts locally by providing ongoing support and funding for code training throughout the state and as a stakeholder in the New Hampshire Building Code Compliance Project. In addition, on a national level, the Company is monitoring efforts such as the recent agreement[12] between the Association of Home Appliance Manufactures (AHAM) and the American Council for an Energy-Efficient Economy (ACEEE) to significantly improve efficiency standards for refrigerators, freezers, clothes washers, clothes dryers, dishwashers, and room air conditioners. ACEEE estimates this agreement could save 453 million kWh annually in New Hampshire by 2020.

[12] http://www.aham.org/ht/a/GetDocumentAction/i/49956

### G.4. Forward Capacity Market

The establishment of the Forward Capacity Market and the obligation for ISO-New England to pay for demonstrable demand-side capacity reductions may result in unforeseen market forces and consequences. For example, several of PSNH's large customers have indicated their reluctance to sign an agreement to participate in the CORE Programs because in doing so they must forego any rights to capacity payments from ISO-New England[13]. The intent of this provision was to prevent "double dipping" whereby a CORE Program participant would receive both a CORE Program incentive and an ISO-New England payment for installing the same energy efficiency measure. Customers who sign the participation agreement allow PSNH to receive any ISO-New England capacity payments on behalf of all customers and the payments received are then used to fund additional efficiency measures. However, an unintended consequence of this provision could be that a significant number of customers decide not to participate in the CORE Programs. While PSNH does not feel this is a significant concern at this time, the situation needs to be watched closely, and its impacts on the CORE Programs evaluated.

### G.5. Impact of Environmental Regulations on DSM Cost Effectiveness

The avoided cost of electricity used to evaluate Energy Efficiency program cost-effectiveness is based on a long-term forecast of the prices of energy and capacity in the New England wholesale market. The forecasted prices account for the estimated cost of compliance with regulations governing $CO_2$ emissions. The inclusion of compliance costs in the avoided cost of electricity increases the present value of the economic benefits and accordingly increases the cost-effectiveness of the programs.

## H. Demand Side Summary

The following summarizes key points and conclusions regarding demand-side management resources covered in Section IV:

- The CORE Programs offered today are cost-effective and provide technical and financial assistance to all classes of customers. These programs are having an appreciable impact on New Hampshire's energy use, and they provide the base upon which significantly expanded programs can achieve New Hampshire's full energy efficiency potential.

- The Potentially Obtainable Scenario developed by GDS Associates served as the starting point for development of the Market Potential Scenario. The Market Potential Scenario represents the savings PSNH believes can be achieved in its service territory after a detailed evaluation of the Potentially Obtainable Scenario and after incorporating PSNH's knowledge and experience with the CORE Programs.

---

[13] This provision was approved by the Commission as part of the 2007 CORE programs (reference *2007 CORE NH Energy Efficiency Programs*, DE 06-135, September 29, 2006, page 4).

- Increasing avoided energy costs to include the full climate sustainable costs of $CO_2$ impacts the potentially available cost-effective savings by less than 5 percent.

Achieving the Market Potential Scenario savings within PSNH's service territory will increase efficiency program costs by 140 percent by 2015.

# V. Assessment of Supply Resources

This section assesses PSNH's supply resources beginning with an overview of PSNH's diversified mix of generating resources including hydroelectric, coal, oil, natural gas, combustion turbines, as well as purchases from independent power producers and purchased power contracts. This section also outlines PSNH's future renewable power resources and discusses how PSNH creates a balanced portfolio using a mix of owned generation and power purchases.

## A. Existing Generation Supply

PSNH's generation supply portfolio is comprised of a balanced mix of resource types including three fossil fuel-fired stations, nine hydroelectric facilities, five fossil fuel combustion turbines and long- and short-term purchased power contracts or rate orders. In 2009, PSNH supplied 68 percent of the energy needs and 69 percent of the capacity needs of its default energy service requirements using owned generation, IPPs and long-term purchases. PSNH's owned and operated generating facilities can produce more than 1,110 megawatts of electric power. Specific descriptions of PSNH's supply portfolio resources are provided in the sections below.

### A.1. Fossil Fuel Generating Resources

PSNH operates three existing fossil fuel-fired generating stations. Currently Merrimack Station and Schiller Station's two coal fired units are used as base load resources and Newington Station is used as an oil-fired or gas-fired peaking and intermediate resource. Historically, PSNH has relied upon these three stations to meet a major portion of the load requirements of its default energy service customers and has continually invested in maintaining the facilities. Equipment such as turbines, blades and generator rotors, boiler components and auxiliary equipment have been installed as required to maintain reliability, and PSNH has demonstrated its commitment to the environment through a very significant and sustained investment in pollution reduction equipment at these stations. Exhibit V-1 describes PSNH's fossil fuel stations. The sections below describe each facility in greater detail.

**Exhibit V-1: PSNH's Fossil Fuel Stations**

| Units | Fuel Type | Winter Capacity Rating (MW) | Summer Capacity Rating (MW) | Energy (MWh) (Avg '05-'09) |
|---|---|---|---|---|
| Merrimack 1 (MK1) | Coal | 114.000 | 112.500 | 858,632 |
| Merrimack 2 (MK2) | Coal | 337.200 | 338.375 | 2,106,400 |
| Schiller (SR4) | Coal/Oil | 48.000 | 47.500 | 310,626 |
| Schiller (SR6) | Coal/Oil | 48.580 | 47.938 | 312,087 |
| Newington (NT1) | Oil/Gas | 400.200 | 400.200 | 401,589 |
| **Total** | | **947.980** | **946.513** | **3,989,334** |

## Merrimack Station

Merrimack Station, located in Bow, New Hampshire, is PSNH's primary base load plant. Merrimack Station has two coal-fired, wet bottom cyclone boilers (MK1 and MK2 or Unit 1 and Unit 2), two combustion turbines (CT1 and CT2) typically operated during periods of highest seasonal peak demand, a temporary auxiliary boiler, an emergency generator and the necessary support equipment to generate electricity.

MK1 began commercial operation in 1960. At full load, Unit 1 consumes approximately 1,000 tons of coal per day. The unit burns crushed coal in the Babcock & Wilcox-designed boiler's three cyclone burners. These cyclones are attached to the front of the boiler and burn the coal efficiently at temperatures in excess of 3,500° F. A regenerative type air heater is employed on Unit 1. Unit 1 produces 815,000 pounds of steam per hour at 1,800 psi and 1,000° F. This steam is supplied to the Westinghouse turbine generator, with one return to the boiler for reheating back to 1,000° F. The turbine generator is a tandem compound design with a double flow low pressure turbine. The turbine consists of 37 stages, and operates at 3,600 rpm. The Westinghouse generator is directly connected to the turbine and produces output of 133,689 kVA at 5,360 amps at a 0.85 power factor. The step-up transformer located outside of the turbine room wall increases the voltage to 115 kV for its interconnection with the New England transmission system in the adjacent switchyard.

MK2 began commercial operation in 1968. At full load, Unit 2 can consume approximately 3,000 tons of coal per day in a Babcock & Wilcox-designed boiler, with seven cyclone burners, four on the front of the boiler and three on the rear. The same types of crushed coal used in Unit 1 can be used in Unit 2. The universal pressure boiler produces 2,332,000 pounds of steam per hour at 2,400 psi and 1,000°F. Unit 2 employs a tubular air preheater. As with Unit 1, steam is supplied to a Westinghouse turbine. After use in the high pressure turbine section, steam is reheated in the boiler, returning it to a temperature of 1,000° F before being used in the intermediate and low pressure turbine sections. The Unit 2 turbine is of a tandem compound design, with two double flow low pressure sections, and a total of 24 stages. The Westinghouse generator is directly connected to the turbine and produces output of 384,000 kVA at 9,238 amps at a 0.90 power factor. The step-up transformer located outside the turbine room wall increases the voltage to 115 kV for interconnection with the New England transmission system in the adjacent switchyard. In the spring of 2008, a new, more-efficient high pressure/intermediate pressure (HP/IP) turbine was installed on Merrimack Unit 2. The HP/IP project involved the replacement of one of the six steam turbine components with a functionally equivalent component. The new, state-of-the-art turbine blades are more energy efficient resulting in more generation for the same amount of fuel burned.

PSNH has aggressively pursued fuel switching and fuel blending at Merrimack Station in order to reduce sulfur dioxide ($SO_2$) emissions. PSNH is currently blending a mix of low sulfur domestic and foreign coals in order to achieve an effective sulfur content of approximately 1.0 percent to 1.2 percent on each unit. Restricted to coals with inherently-low fusion temperatures, Merrimack Station's fuel supply consists of domestic coal from Pennsylvania, West Virginia, Ohio, and Virginia as well as foreign coal, primarily from South America.

More than $50 million has been invested in environmental initiatives at Merrimack Station since 1989. MK1 and MK2 are each equipped with two electrostatic precipitators (ESPs), operated in series, for the control of particulate emissions, and a selective catalytic reduction system, for the control of NOx emissions.

MK1 and MK2 were designed and constructed with original ESPs. However, supplemental ESPs were installed on MK1 and MK2 in 1989 and 1998, respectively, significantly reducing particulate emissions even further.

In 1995, MK2 became the first coal-fired utility boiler in the United States to install a selective catalytic reduction (SCR) system for the reduction of nitrogen oxide (NOx) emissions. In addition, a selective non-catalytic reduction system (SNCR) was installed on MK1 to reduce NOx emissions. In 1999, in order to achieve even greater NOx emissions reductions, the SNCR on MK1 was replaced with an SCR system. The installation of SCR systems on MK1 and MK2 has resulted in reductions in NOx emissions greater than 85 percent from each unit.

Merrimack Station is currently constructing a wet flue-gas desulfurization system (wet scrubber) to reduce mercury and sulfur emissions from Merrimack Unit 1 and Unit 2. The New Hampshire legislature passed RSA 125-O:13 in 2006 requiring PSNH to install a wet scrubber at Merrimack Station no later than July 1, 2013. The project is currently expected to be completed by July 1, 2012, a year early.

## Schiller Station

Schiller Station, located in Portsmouth, New Hampshire, is comprised of three utility boilers (SR4, SR5, and SR6 or Unit 4, Unit 5, or Unit 6), a combustion turbine presently operating as a load shaving unit (CT1), an emergency generator, a primary coal crusher, and the necessary support equipment to generate electricity. Schiller Station’s Unit 5 was modified in 2006 with the construction of a new wood boiler to replace the existing coal/oil boiler and is described in further detail in the Biomass section.

Schiller's steam units have historically served a base load or intermediate load role for NEPOOL. The units have the capability of starting up and shutting down daily if needed, but they have also effectively served in the base load role.

Originally completed in 1949, Schiller Station is PSNH's third largest generating plant. Its three existing units were built in 1952 (Unit 4), 1955 (Unit 5), and 1957 (Unit 6). Units 4 and 5 were originally designed to burn coal, and did so for the first six months of their operation. Both were then converted to burn oil as the primary fuel. Unit 6 was designed to burn oil originally. In 1984, Units 4, 5 and 6 were converted to burn coal. Units 4 and 6 continue to be able to burn coal and/or oil as boiler fuel, making them adaptable to changing fuel markets.

Schiller’s coal supply consists of low sulfur (typically 1 percent sulfur or lower) coal from Venezuela and Colombia. Occasionally, domestic coal is delivered by barge to Schiller in order to maintain adequate inventory levels. Due to its boiler characteristics, Schiller Station is better able to burn a wider range of available coals than Merrimack Station.

Schiller Station has undergone millions of dollars in environmental optimizations and improvements over the years. The emission controls for each unit at Schiller Station consist of low-NOx burners, a SNCR system and over fire air system for the reduction of NOx emissions and an ESP for the reduction of particulate emissions.

In 1999, SR4 and SR6 were retrofitted with burner equipment that reduces nitrogen oxide (NOx) emission levels by 50 percent. Subsequently, a selective non-catalytic reduction system and an over fire air system were installed. Further NOx reductions were obtained with burner replacements on Unit 4 in the fall of 2006 and on Unit 6 in the spring of 2007 for total NOx reductions of greater than 70 percent.

**Newington Station**

Newington Station, located in Newington, New Hampshire, was designed as a peaking unit for quick start up and load change capability. Newington Station is comprised of one utility boiler (NT1 or Unit 1), two auxiliary boilers, an emergency generator, and the necessary support equipment to generate electricity.

NT1 is PSNH's largest single generating unit. Newington Unit 1 was originally designed to burn crude oil and No. 6 fuel oil. The unit was designed for fast response and startup, making it an attractive unit for intermediate or daily cycling service.

The station began commercial operation in 1974 and was modified to burn natural gas in 1992. At full load the unit consumes nearly 17,000 barrels of oil per day in the Combustion Engineering-designed tangentially-fired boiler. Four elevations of burners, located in the boiler corners, provide the combustion process for the unit. Newington Unit 1 produces 3 million pounds of steam per hour at 1,800 psi and 950° F. This steam is supplied to a Westinghouse turbine generator, with one return to the boiler for reheating back to 950° F. The turbine generator is of a tandem compound design with a double flow low pressure section. The turbine consists of 18 stages and operates at 3,600 rpm. The Westinghouse generator is directly connected to the turbine and produces output of 24 kV at 12,000 amps at a 0.90 power factor. The step-up transformer located outside the turbine room wall increases the voltage to 345 kV for interconnection with the New England transmission system in the adjacent switchyard.

Emissions reductions at Newington Station began with the installation of new gas lines and burners in 1992. The emissions control system on NT1 includes an ESP, for the reduction of particulate emissions, and various NOx emissions controls including water wall soot blowers, arch blowers, low-NOx burners, a boiler tempering skid and an over fire air system. Employing these various methods, PSNH has been able to reduce the amount of nitrogen oxide emitted by NT1 by more than 50 percent. A new control system and fly ash collection system was also installed at Newington Station during its spring 2005 outage.

## A.2. Combustion Turbines

PSNH operates five combustion turbines, two of which are standalone. The combustion turbines are utilized to produce power during high demand periods. Merrimack Station's two combustion turbines operate during periods of highest seasonal peak demand or when quick response in generation is required to maintain electrical system reliability. Schiller Station has a separate combustion turbine, a jet engine capable of burning either AV Jet Kero II or natural gas. The two standalone combustion turbines, Lost Nation and White Lake, are managed by a single management and support organization and are utilized to produce power during high demand periods and/or to maintain electrical system reliability. Exhibit V-2 describes PSNH's five combustion turbines.

**Exhibit V-2: PSNH's Combustion Turbines**

| Name | Winter Capacity Rating (MW) | Summer Capacity Rating (MW) | Energy (MWh) (Avg '05-'09) |
|---|---|---|---|
| Merrimack CT1 | 21.676 | 16.826 | 228 |
| Merrimack CT2 | 21.304 | 16.804 | 195 |
| Schiller CT | 19.500 | 17.621 | 408 |
| Lost Nation | 18.082 | 14.069 | 292 |
| White Lake | 22.397 | 17.447 | 551 |
| **Total** | **102.959** | **82.767** | **1,674** |

## A.3. Hydroelectric Generating Stations

PSNH owns nine hydroelectric stations with 20 units that supply approximately 4 percent of PSNH's default energy service needs. Exhibit V-3 summarizes the details surrounding each facility. The hydroelectric facilities are managed by a single management and support organization. Coordinated operation of the units is essential to achieve maximized value. Three of these units share a common waterway, which can impact production output between the sites. In addition, Hooksett Station provides the cooling water impoundment required for once-through cooling of the Merrimack Station.

Smith, Gorham and Canaan hydroelectric generating stations are located in an "Upper Hydro" location. Ayers Island and Eastman Falls hydroelectric generating stations are referred to as the "Middle Hydro" location. Amoskeag, Hooksett, Garvins Falls and Jackman hydroelectric generating stations are located in the "Lower Hydro" area.

Each hydroelectric facility is an unmanned station and is monitored and controlled by supervisory control from the ESCC in Manchester, New Hampshire. Of the nine facilities, eight operate under the jurisdiction of FERC licenses. The ninth facility, Jackman Station, is not a FERC-jurisdictional project, but is subject to applicable state regulations. Three of the lower hydro units (Amoskeag, Hooksett and Garvins Falls named the "Merrimack Project") received a 40-year FERC license renewal in 2007 and Canaan received a 30-year FERC license renewal in 2009. The licenses for four of the hydroelectric facilities operated under FERC licenses are long-lived and expire between 2018 and 2036.

In 2006, a new renewable project was completed at Smith Hydro. The $2.75 million project replaced the water turbine or "runner" with a runner of a new, more efficient design. Smith Hydro, installed in 1948, is PSNH's largest single hydro unit, located in Berlin, New Hampshire. The project resulted in 8 percent more efficiency as a result of the new runner using less water flow per kilowatt and increasing the annual output of renewable hydro power to 17.6 MW.

**Exhibit V-3: PSNH's Licensed Hydroelectric Facilities**

| Licensed facilities | Winter Capacity Rating (MW) | Summer Capacity Rating (MW) | Energy (MWh) (Avg '05-'09) | License issued | License expiration date | FERC project no. |
|---|---|---|---|---|---|---|
| Amoskeag | 17.500 | 15.818 | 99,017 | 2007 | 2047 | 1893 |
| Garvins Falls/ Hooksett | 14.000 | 11.595 | 56,703 | 2007 | 2047 | 1893 |
| Eastman Falls | 6.470 | 5.132 | 28,914 | 1/26/1988 | 1/1/2018 | 2457 |
| Ayers Island | 9.080 | 7.899 | 49,870 | 4/1/1996 | 4/1/2036 | 2456 |
| Smith | 17.600 | 11.469 | 114,079 | 8/1/1994 | 8/1/2024 | 2287 |
| Gorham | 2.050 | 1.951 | 12,227 | 8/1/1994 | 8/1/2024 | 2288 |
| Canaan | 1.100 | 1.100 | 7,353 | 8/1/2009 | 8/1/2039 | 7528 |
| Jackman[14] | 3.305 | 3.550 | 9,933 | N/A | N/A | N/A |
| **Total** | **71.105** | **58.514** | **378,097** | | | |

Note: Amoskeag, Hooksett and Garvins Falls are currently covered under one FERC operating license designated the Merrimack River Project.

## A.4. Biomass

Schiller Station's Unit 5 (SR 5) was modified in 2006 with the construction of a new wood-fired boiler to replace the existing coal/oil-fired boiler. PSNH replaced a 50 megawatt coal-fired boiler at Schiller Station with a new boiler system which uses wood chips and other clean, low-grade wood materials for fuel. This conversion, named Northern Wood Power (NWP), allows PSNH to economically produce cleaner electric energy from environmentally sound renewable resources. Northern Wood Power serves in a base load role to meet PSNH's default energy service customer requirements.

PSNH's current portfolio of owned and operated power plants uses coal, oil, natural gas, water (hydro), and wood as fuels. Wood-fired generation is one step in providing more diversity to PSNH's fuel mix, and will help ensure a reliable supply of affordable electric energy for customers of PSNH. Exhibit V-4 lists the operating details for PSNH's biomass facility.

**Exhibit V-4: PSNH's Biomass Facilities**

| Name | Winter Capacity Rating (MW) | Summer Capacity Rating (MW) | Energy (MWh) (Avg '06-'09) |
|---|---|---|---|
| Schiller 5 (SR5) | 45.816 | 43.082 | 241,230 |
| **Total** | **45.816** | **43.082** | **241,230** |

[14] On May 26, 1988, FERC issued an order finding that the project is not subject to FERC jurisdiction.

## A.5. Jointly Owned and Generation Purchased Power Contracts

In addition to the generation resources described above, PSNH holds an ownership interest in Wyman 4 located in Yarmouth, Maine and a power purchase agreement with Vermont Yankee ending in 2012 and receives a portion of the power produced by those facilities. Exhibit V-5 describes PSNH's ownership and entitlement contracts.

**Exhibit V-5: PSNH's Ownership and Entitlement Contracts**

| Name | Type | PSNH's Share | Winter Entitlement (MW) | Summer Entitlement (MW) |
|---|---|---|---|---|
| Vermont Yankee | Nuclear | 3.32% | 20.878 | 20.088 |
| Wyman 4 | Oil | 3.14% | 19.186 | 18.970 |
| **Total** | | | **40.064** | **39.058** |

## A.6. Independent Power Producer Contracts and Rate Orders

Under the Public Utility Regulatory Policies Act (PURPA), PSNH is required to interconnect and purchase the generation from Qualifying Facilities (QF). The Qualifying Facilities or Independent Power Producer (IPP) contracts and rate orders include a mix of resources fueled by water, wind, wood, landfill gas and trash and account for 5 percent of PSNH's resource mix. Exhibit V-6 describes PSNH's IPP contract and rate order obligations as of June 2010.

**Exhibit V-6: PSNH's Long-Term IPP Contract and Rate Order Obligations, June 2010**

| Name | Type | Winter Capacity Rating (MW) | Summer Capacity Rating (MW) | Annual Energy (MWh) | Rate Order/ Contract End Date |
|---|---|---|---|---|---|
| West Hopkinton Hydro | Hydro | 1.250 | 0.396 | 3,300 | Oct-2012 |
| Garland Mill | Hydro | 0.000 | 0.000 | 33 | Oct-2012 |
| Penacook Lower Falls | Hydro | 4.615 | 2.803 | 18,800 | Sep-2013 |
| Rollinsford Hydro | Hydro | 1.500 | 0.774 | 6,000 | Sep-2013 |
| Great Falls Lower | Hydro | 1.100 | 0.366 | 3,400 | Apr-2014 |
| Newfound Hydro | Hydro | 1.367 | 0.649 | 6,000 | Aug-2014 |
| Nashua Hydro | Hydro | 0.840 | 0.803 | 4,300 | Dec-2014 |
| Steels Pond Hydro | Hydro | 0.975 | 0.190 | 2,600 | Dec-2014 |
| Watson Dam | Hydro | 0.250 | 0.049 | 1,000 | Jan-2015 |
| Sugar River Hydro | Hydro | 0.150 | 0.000 | 600 | Dec-2015 |
| Four Hills Landfill | Landfill Gas | 0.307 | 0.000 | 4,800 | Mar-2016 |
| Peterborough Lower Hydro | Hydro | 0.284 | 0.000 | 900 | Dec-2017 |
| Peterborough Upper Hydro | Hydro | 0.400 | 0.000 | 1,100 | Dec-2017 |
| WES Concord MSW | Trash | 3.600 | 1.938 | 103,000 | Dec-2018 |
| Penacook Upper Falls | Hydro | 5.000 | 2.588 | 13,900 | Dec-2021 |

| Name | Type | Winter Capacity Rating (MW) | Summer Capacity Rating (MW) | Annual Energy (MWh) | Rate Order/ Contract End Date |
|---|---|---|---|---|---|
| Briar Hydro | Hydro | 3.000 | 2.101 | 21,100 | Dec-2022 |
| Errol Dam | Hydro | 23.500 | 2.629 | 17,000 | Dec-2023 |
| Lempster Wind | Wind | 12.761 | 12.159 | 63,000 | Sep-2027 |
| **Total Long-Term IPP Contracts and Rate Orders** | | **60.899** | **27.445** | **268,382** | |
| Total IPP Replacement Power Contracts | | 1.250 | 0.396 | 75,842 | |

Note: Capacity Rating is Seasonal Claimed Capacity (SCC) as reported to ISO-New England.

## B. Load Resource Balance

As a load-holding entity, PSNH is responsible for having sufficient energy to meet the hourly needs of its default energy service customers and is also required to pay its share of the ISO-New England capacity requirement, net of revenues received for its capacity resources. PSNH meets its energy requirements through its owned generation, PURPA-mandated purchases under short term rates and long term rate orders, long-term IPP contracts, and through supplemental purchases of energy from the market. In 2009, PSNH supplied 68 percent of total energy requirements through its owned generation, IPPs and other long-term entitlements and 32 percent through spot market and bilateral energy purchases. Appendix D provides detail on the specific supply resources used to serve PSNH's 2009 default energy service requirement. In 2009, PSNH supplied 69 percent of total capacity requirements through its owned generation, IPPs and other long-term entitlements (including Hydro-Quebec interconnection capacity credits) and 31 percent through payments in the ISO-New England administered market. Appendix E provides detail on the resources used to serve PSNH's 2009 ISO-New England capacity obligation.

## B.1. Existing Power Supply Resource Portfolio

Exhibit V-7 lists the existing generating resource portfolio PSNH will use to serve its customers' default energy service requirements during the planning period. As shown in the exhibit, PSNH's existing supply resources during this period total about 1,207 MW for the summer months. The portfolio is comprised of the following resource groups (numbers may not add due to rounding):

- Coal (546 MW from Merrimack and Schiller Stations)
- Oil (419 MW from Newington and Wyman-4)
- Hydroelectric (59 MW from nine stations)
- Combustion turbines (83 MW from five units)
- Wood (43 MW from Schiller Unit 5)
- Nuclear (20 MW from the Vermont Yankee purchased power arrangement)
- Non-utility generation (27 MW from IPPs under rate orders or contracts and 10 MW from an IPP replacement contract)

IPPs that may or may not continue to provide power to PSNH under short-term rates are not listed and are not considered PSNH's supply resources for forward looking purposes of this planning document.

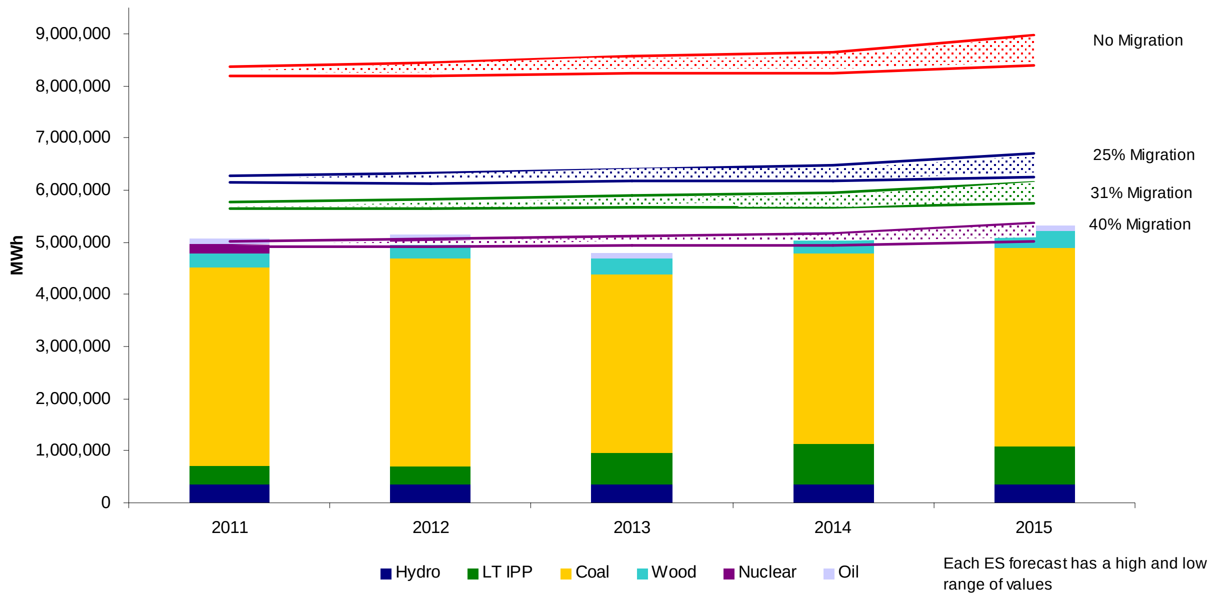
**Exhibit V-7: PSNH Resource Portfolio**

| Name | Fuel Type | Winter Rating (MW) | Summer Rating (MW) | Interest | Winter Entitlement (MW) | Summer Entitlement (MW) |
|---|---|---|---|---|---|---|
| Amoskeag | Hydro | 17.500 | 15.818 | 100.00% | 17.500 | 15.818 |
| Ayers Island | Hydro | 9.080 | 7.899 | 100.00% | 9.080 | 7.899 |
| Caanan | Hydro | 1.100 | 1.100 | 100.00% | 1.100 | 1.100 |
| Eastman Falls | Hydro | 6.470 | 5.132 | 100.00% | 6.470 | 5.132 |
| Garvins Falls/Hooksett | Hydro | 14.000 | 11.595 | 100.00% | 14.000 | 11.595 |
| Gorham | Hydro | 2.050 | 1.951 | 100.00% | 2.050 | 1.951 |
| Jackman | Hydro | 3.305 | 3.550 | 100.00% | 3.305 | 3.550 |
| Smith | Hydro | 17.600 | 11.469 | 100.00% | 17.600 | 11.469 |
| Vermont Yankee | Nuclear | 628.000 | 604.250 | 3.32% | 20.878 | 20.088 |
| Merrimack Unit 1 | Coal | 114.000 | 112.500 | 100.00% | 114.000 | 112.500 |
| Merrimack Unit 2 | Coal | 337.200 | 338.375 | 100.00% | 337.200 | 338.375 |
| Schiller Unit 4 | Coal/Oil | 48.000 | 47.500 | 100.00% | 48.000 | 47.500 |
| Schiller Unit 6 | Coal/Oil | 48.580 | 47.938 | 100.00% | 48.580 | 47.938 |
| Newington | Oil/Natural Gas | 400.200 | 400.200 | 100.00% | 400.200 | 400.200 |
| Wyman 4 | Oil | 610.375 | 603.488 | 3.14% | 19.186 | 18.970 |
| Schiller Unit 5 | Wood | 45.816 | 43.082 | 100.00% | 45.816 | 43.082 |
| Merrimack CT 1 | Jet Fuel | 21.676 | 16.826 | 100.00% | 21.676 | 16.826 |
| Merrimack CT 2 | Jet Fuel | 21.304 | 16.804 | 100.00% | 21.304 | 16.804 |
| Schiller CT | Jet Fuel | 19.500 | 17.621 | 100.00% | 19.500 | 17.621 |
| Lost Nation | Jet Fuel | 18.082 | 14.069 | 100.00% | 18.082 | 14.069 |
| White Lake | Jet Fuel | 22.397 | 17.447 | 100.00% | 22.397 | 17.447 |
| West Hopkinton Hydro | Hydro | 1.250 | 0.396 | 100.00% | 1.250 | 0.396 |
| Garland Mill | Hydro | 0.000 | 0.000 | 100.00% | 0.000 | 0.000 |
| Penacook Lower Falls | Hydro | 4.615 | 2.803 | 100.00% | 4.615 | 2.803 |
| Rollinsford Hydro | Hydro | 1.500 | 0.774 | 100.00% | 1.500 | 0.774 |
| Great Falls Lower | Hydro | 1.100 | 0.366 | 100.00% | 1.100 | 0.366 |
| Newfound Hydro | Hydro | 1.367 | 0.649 | 100.00% | 1.367 | 0.649 |
| Nashua Hydro | Hydro | 0.840 | 0.803 | 100.00% | 0.840 | 0.803 |
| Steels Pond Hydro | Hydro | 0.975 | 0.190 | 100.00% | 0.975 | 0.190 |
| Watson Dam | Hydro | 0.250 | 0.049 | 100.00% | 0.250 | 0.049 |
| Sugar River Hydro | Hydro | 0.150 | 0.000 | 100.00% | 0.150 | 0.000 |
| Four Hills Landfill | Landfill Gas | 0.307 | 0.000 | 100.00% | 0.307 | 0.000 |
| Peterborough Lower Hydro | Hydro | 0.284 | 0.000 | 100.00% | 0.284 | 0.000 |
| Peterborough Upper Hydro | Hydro | 0.400 | 0.000 | 100.00% | 0.400 | 0.000 |
| Penacook Upper Falls | Hydro | 3.600 | 1.938 | 100.00% | 3.600 | 1.938 |
| Briar Hydro | Hydro | 5.000 | 2.588 | 100.00% | 5.000 | 2.588 |
| Errol Dam | Hydro | 3.000 | 2.101 | 100.00% | 3.000 | 2.101 |
| Lempster Wind | Wind | 23.500 | 2.629 | 90.00% | 21.150 | 2.366 |
| WES Concord MSW | Trash | 12.761 | 12.159 | 100.00% | 12.761 | 12.159 |
| IPP Replacement Power | | 10.000 | 10.000 | 100.00% | 10.000 | 10.000 |
| **Totals** | | **2,477.134** | **2,376.059** | | **1,276.473** | **1,207.116** |

## B.2. Forecast of Energy Requirement and Supply Resources

Exhibit V-8 below shows PSNH's forecast of default energy service requirements under various migration and high and low load scenarios and the forecast of PSNH's supply resources. PSNH's forecasted supplemental energy purchases needed to meet default energy service requirements range significantly over the planning period depending on the level of assumed migration from no additional purchases needed under 40 percent migration to as much as 3,649 GWh in 2015 assuming no migration and a high load forecast.

**Exhibit V-8: PSNH Energy Balance**




| | GWh | | | | |
|---|---|---|---|---|---|
| | **2011** | **2012** | **2013** | **2014** | **2015** |
| Expected Generation | 5,063 | 5,143 | 4,792 | 5,192 | 5,312 |
| | | | | | |
| **Migration Level: 40%** | | | | | |
| Total ES Requirement – High scenario | 5,012 | 5,059 | 5,125 | 5,178 | 5,367 |
| Supplemental ES Purchases – High scenario | (50) | (85) | 333 | (15) | 56 |
| Total ES Requirement – Low scenario | 4,917 | 4,905 | 4,937 | 4,938 | 5,024 |
| Supplemental ES Purchases – Low scenario | (146) | (239) | 145 | (255) | (287) |
| | | | | | |
| **Migration Level: 31%** | | | | | |
| Total ES Requirement – High scenario | 5,764 | 5,817 | 5,891 | 5,945 | 6,153 |
| Supplemental ES Purchases – High scenario | 702 | 674 | 1,099 | 753 | 841 |
| Total ES Requirement – Low scenario | 5,655 | 5,640 | 5,671 | 5,660 | 5,741 |
| Supplemental ES Purchases – Low scenario | 592 | 496 | 879 | 468 | 429 |
| | | | | | |
| **Migration Level: 25%** | | | | | |
| Total ES Requirement – High scenario | 6,266 | 6,326 | 6,408 | 6,469 | 6,696 |
| Supplemental ES Purchases – High scenario | 1,204 | 1,183 | 1,616 | 1,277 | 1,385 |
| Total ES Requirement – Low scenario | 6,147 | 6,133 | 6,171 | 6,161 | 6,252 |
| Supplemental ES Purchases – Low scenario | 1,084 | 990 | 1,379 | 969 | 940 |
| | | | | | |
| **Migration Level: 0%** | | | | | |
| Total ES Requirement – High scenario | 8,357 | 8,446 | 8,564 | 8,652 | 8,960 |
| Supplemental ES Purchases – High scenario | 3,295 | 3,303 | 3,772 | 3,460 | 3,649 |
| Total ES Requirement – Low scenario | 8,199 | 8,190 | 8,251 | 8,250 | 8,382 |
| Supplemental ES Purchases – Low scenario | 3,136 | 3,047 | 3,459 | 3,058 | 3,070 |

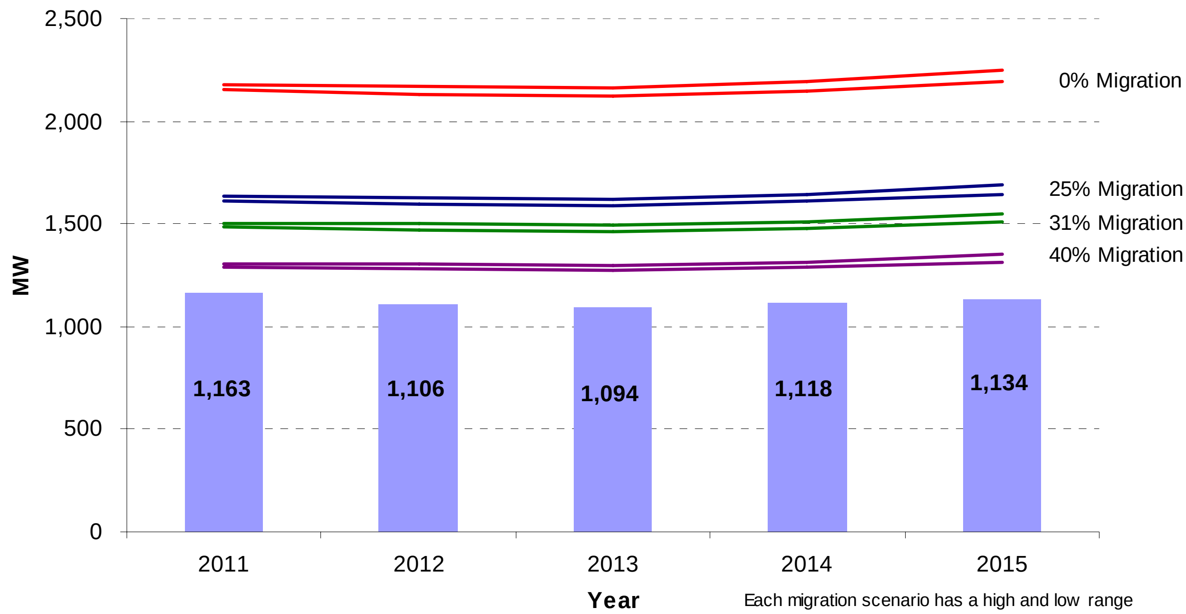
Exhibit D-4 in Appendix D further delineates the forecasted supplemental energy purchases needed by peak and off peak periods. As discussed previously and below in this plan, in practice these needs are further disaggregated into monthly and daily needs and are expressed in average MW when considering volumetric purchases. Further detail on the forecasted supply resources can be found in Appendix D such as a forecast of the energy production from existing supply resources during each year of the planning period and by on peak and off peak periods. Other than Newington Station and the combustion turbines, all supply resources are assumed to operate as baseload assets, taking into account historical availabilities, 20-year hydro averages, and anticipated maintenance. In the exhibits in Appendix D, the combustion turbines are assumed to provide zero MWh, but in reality provide an important source of reserves and energy during peak load and/or high price hours.

Newington Station's production shown in the exhibits in Appendix D is a result of operating at various output levels only during some on-peak hours in the months of January, February, July and August. This is based on a recent review of Newington's forecasted economics relative to market-based purchases which indicate customer savings during the noted months. Appendix G of this plan contains a Continuing Unit Operations study analyzing the value that Newington Station provides to PSNH's customers.

### B.3. Forecast of Capacity Requirement and Supply Resources

Exhibit V-9 shows the annual average MW PSNH will need to support in the capacity market during the planning period for the varying default energy service migration levels discussed above net of its credited capacity. The current capacity market design compensates resources for taking on capacity obligations and bills load serving entities for their share of the installed capacity requirement. PSNH uses its capacity obligation revenues to offset the bill it receives for serving default energy service load. The exhibits in Appendix F provide monthly details and the analytical assumptions that support the annual results. Exhibit F-1 in Appendix F is a review of the capacity balance forecast under the Forward Capacity Market rules, which are applicable beginning in June 2010. PSNH's capacity supply forecast is based on the assets listed in Exhibit V-7, as adjusted to account for the expiration dates of certain IPPs and the monthly schedule of Hydro-Quebec interconnection credits and how resources are valued in the ISO-New England Forward Capacity Market.

## Exhibit V-9: PSNH Capacity Balance




| | | Average Annual MW | | | | |
|---|---|---|---|---|---|---|
| | | **2011** | **2012** | **2013** | **2014** | **2015** |
| **PSNH Controlled Resources** | | 1,163 | 1,106 | 1,094 | 1,118 | 1,134 |
| | | | | | | |
| **ISO-New England Installed Capacity Resources (ICR)** | High | 33,534 | 33,413 | 33,298 | 33,732 | 34,641 |
| | Reference | 33,317 | 33,112 | 32,975 | 33,361 | 33,883 |
| | Low | 33,110 | 32,830 | 32,667 | 33,001 | 33,707 |
| **PSNH's Share of ICR** | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| | | | | | | |
| **PSNH's Share of ISO-New England Installed Capacity Resources (ICR)** | | | | | | |
| **Migration Level: 40%** | | | | | | |
| PSNH ES Capacity Share | High | 1,307 | 1,303 | 1,298 | 1,315 | 1,350 |
| Net Capacity Obligation | High | 144 | 197 | 204 | 197 | 216 |
| PSNH ES Capacity Share | Reference | 1,298 | 1,291 | 1,286 | 1,300 | 1,321 |
| Net Capacity Obligation | Reference | 135 | 185 | 191 | 183 | 187 |
| PSNH ES Capacity Share | Low | 1,290 | 1,279 | 1,273 | 1,287 | 1,314 |
| Net Capacity Obligation | Low | 127 | 174 | 179 | 169 | 180 |
| **Migration Level: 31%** | | | | | | |
| PSNH ES Capacity Share | High | 1,503 | 1,498 | 1,493 | 1,512 | 1,553 |
| Net Capacity Obligation | High | 340 | 392 | 398 | 394 | 419 |
| PSNH ES Capacity Share | Reference | 1,493 | 1,484 | 1,478 | 1,496 | 1,519 |
| Net Capacity Obligation | Reference | 330 | 379 | 384 | 378 | 385 |
| PSNH ES Capacity Share | Low | 1,484 | 1,471 | 1,464 | 1,480 | 1,511 |
| Net Capacity Obligation | Low | 321 | 365 | 370 | 362 | 378 |
| **Migration Level: 25%** | | | | | | |
| PSNH ES Capacity Share | High | 1,634 | 1,628 | 1,623 | 1,643 | 1,688 |
| Net Capacity Obligation | High | 471 | 523 | 528 | 526 | 554 |
| PSNH ES Capacity Share | Reference | 1,623 | 1,613 | 1,607 | 1,626 | 1,651 |
| Net Capacity Obligation | Reference | 460 | 508 | 512 | 508 | 517 |
| PSNH ES Capacity Share | Low | 1,613 | 1,599 | 1,591 | 1,608 | 1,643 |
| Net Capacity Obligation | Low | 450 | 494 | 497 | 490 | 509 |

| | | Average Annual MW | | | | |
|---|---|---|---|---|---|---|
| | | 2011 | 2012 | 2013 | 2014 | 2015 |
| **Migration Level: 0%** | | | | | | |
| PSNH ES Capacity Share | High | 2,178 | 2,171 | 2,163 | 2,191 | 2,250 |
| Net Capacity Obligation | High | 1,015 | 1,065 | 1,069 | 1,073 | 1,116 |
| PSNH ES Capacity Share | Reference | 2,164 | 2,151 | 2,142 | 2,167 | 2,201 |
| Net Capacity Obligation | Reference | 1,001 | 1,045 | 1,047 | 1,049 | 1,068 |
| PSNH ES Capacity Share | Low | 2,151 | 2,133 | 2,122 | 2,144 | 2,190 |
| Net Capacity Obligation | Low | 988 | 1,027 | 1,028 | 1,026 | 1,056 |

Net obligation is share of ISO-New England installed capacity obligation paid for by PSNH Energy Service customers after subtracting revenues received by PSNH controlled resources
*As of the preparation of this plan migration stood at about 31%

## B.4. Fuel Supply and Diversity

During the last few years prior to the recent recession, the energy commodities markets (natural gas and oil) experienced significant price volatility and an upward trend in prices. Even coal, a commodity with a fairly stable price history, had increased in price. However, the recession has put downward pressure on the energy commodities markets. Exhibit V-10 provides annual average fuel prices reported in the United States since 1990 and demonstrates the volatility in the energy commodity markets.

**Exhibit V-10: Commodity Price History**

| | Natural Gas ($/Thousand Cubic Feet) | Residual Fuel Oil 1% or less Sulfur ($/Barrel) | Bituminous Coal ($/Short Ton) |
|---|---|---|---|
| 1990 | 2.38 | 21.50 | 27.43 |
| 1991 | 2.18 | 16.80 | 27.49 |
| 1992 | 2.36 | 16.55 | 26.78 |
| 1993 | 2.61 | 16.51 | 26.15 |
| 1994 | 2.28 | 16.93 | 25.68 |
| 1995 | 2.02 | 18.19 | 25.56 |
| 1996 | 2.69 | 22.22 | 25.17 |
| 1997 | 2.78 | 19.82 | 24.64 |
| 1998 | 2.40 | 14.95 | 24.87 |
| 1999 | 2.62 | 17.05 | 23.92 |
| 2000 | 4.38 | 28.69 | 24.15 |
| 2001 | 4.61 | 26.04 | 25.36 |
| 2002 | 3.68 | 25.70 | 26.57 |
| 2003 | 5.57 | 32.97 | 26.73 |
| 2004 | 6.11 | 33.35 | 30.56 |
| 2005 | 8.47 | 48.22 | 36.80 |
| 2006 | 7.11 | 55.52 | 39.32 |
| 2007 | 7.31 | 60.69 | 40.80 |
| 2008 | 9.26 | 88.12 | 51.39 |
| 2009 | 4.89 | 59.72 | 54.25 |

Source: Energy Information Administration
Notes:
- All prices in Nominal dollars
- EIA Natural Gas prices reported for “Electric Power Sector”
- EIA Residual Oil prices reported for “Sales Price to End Users”
- EIA Coal prices reported exclude transportation

In addition, strained gas pipeline supply capacity and increased demand for coal rail transportation have caused New England prices to climb higher than prices in areas of the country without such deliverability issues. Around New England, the price increases have resulted in higher marginal generation expenses. Electric distribution companies that have divested their generation as part of industry restructuring are exposed to the full impact of price volatility via their total reliance on supplying their customers' energy needs from market-based sources. PSNH's ownership of a diverse portfolio of generation supply resources serves to reduce the impacts of commodity price volatility.

During 2009, approximately 58 percent of PSNH's default energy service requirements were met with coal, wood, oil, hydroelectric and nuclear resources (Vermont Yankee PPA). The coal-fired generation mostly utilized fixed-price coal under medium-term (2- to 3-year) contracts. Similarly, PSNH's hydroelectric facilities and the fixed-price Vermont Yankee purchased power contract provide power without any exposure to commodity price fluctuations. Newington Station is capable of operating on either residual oil or natural gas. Because of the diversity of its supply portfolio, PSNH is largely insulated from the extreme volatility of the natural gas market. Even during periods of high and volatile natural gas prices, PSNH's diversified resource mix provides relative price stability.

## B.5. Fuel Procurement Strategies

PSNH utilizes a fuel procurement strategy that is driven by emission constraints associated with state and federal regulations and State Operating Permits, and generating unit operations and fuel costs. Fuel for PSNH's generating stations is procured on a lowest-evaluated cost basis, which takes into account such factors as commodity price, transportation (logistics and price), heat (BTUs) and ash content, and elemental constituents (sulfur, mercury, etc.).

An annual fuel and emission planning meeting is held with Fuel Department personnel, PSNH Generation staff, and station managers. An additional eight to ten meetings occur throughout the remainder of the year to review year-to-date emissions, fuel procurement activity and delivery topics, station capacity factors to-date, and projected emission rates and capacity factors for the remainder of the year, as well as discussions regarding short- and long-term emissions compliance and fuel procurement scenarios.

### Coal

PSNH's base load coal plants burn approximately 1.5 million tons of bituminous coal per year. Environmental constraints and the limited number of coal types with the right characteristics to be successfully burned at PSNH's generating stations combine to limit the breadth of portfolio of supplies that could be solicited from the market. Specific types and tonnages of coal to be purchased, inventoried, and burned are extensively examined. PSNH has aggressively canvassed the global marketplace in search of fuels that can be reliably burned in PSNH's boilers, while meeting the increasingly restrictive emissions requirements in the most cost-effective manner. The installation of the scrubber at Merrimack Station will provide additional flexibility to comply with $SO_2$ emission requirements potentially broadening our coal procurement opportunities

Transportation logistics also play a key factor in determining the fuel sources supplied to each station. Fuel delivered to Schiller Station and Newington Station is transported via ocean-going marine vessels, while Merrimack Station is served via rail and is supplemented by truck service (transshipped from marine vessels).

PSNH typically issues Requests For Proposals (RFPs) for the majority of its coal supply and supplements the variety of multi-year contracts with spot purchases. Spot purchases can be used to resolve force majeure events, delivery delays, fuel quality variations, capacity factor variations, etc.

Due to its boiler characteristics, Schiller Station is able to burn a wider range of available coals than Merrimack Station, which is restricted to coals with inherently-low fusion temperatures. Schiller Station has been supplied with low-cost, low sulfur (typically 1 percent sulfur or lower) coal from Venezuela and Colombia delivered by handy-size ships (in cargo lot sizes of 30,000 to 40,000 tons). Occasionally, barges of domestic coal are interspersed into Schiller Station in order to maintain adequate inventory levels as required. It is anticipated that Schiller Station will continue to be supplied with offshore coal in the foreseeable future.

Merrimack Station has aggressively pursued fuel switching and tested a variety of fuel blends in order to comply with state and federal regulations. It is currently blending a mix of domestic and foreign coals in order to achieve a blended sulfur content of approximately 1.1 to 1.3 percent on each unit. Merrimack Station is supplied with low fusion temperature domestic coal from northern Appalachia, namely Pittsburgh seam coal located in southwestern Pennsylvania. It also receives coal originating in central Appalachia. These coals are typically procured using term agreements and, as necessary, purchased in the spot market to supplement the term purchases. Rail service is a two- or three-line haul and determines 40 to 50 percent of the delivered cost of Merrimack Station's coal supply. Merrimack Station has been able to take advantage of the favorable offshore coal prices by transshipping a percentage of its coal requirements through Schiller Station. This coal is transshipped through Schiller Station's coal yard and is delivered to Merrimack Station via truck service. The cost savings of using foreign coal, as compared to displacing and burning higher priced domestic coal of similar quality is significant. It is expected that the current supply sources will continue for Merrimack Station into the foreseeable future.

**Oil and Natural Gas**

Newington Station has played the role of the 'swing' station in terms of allowing PSNH to meet its emissions targets, with Newington Station burning natural gas and/or a blend of residual oil (up to 2 percent sulfur) as necessary. When a substantial margin to the emission caps exists, Newington Station is free to dispatch on either oil or natural gas, dependant on ISO-New England market clearing prices, commodity price differentials, and system electrical supply and demand. Fuel oil is procured via pre-scheduled cargos or barges based on forecasted utilization.

**Wood**

Wood fuel is procured for Schiller Station's Unit 5 boiler, known as Northern Wood Power (NWP). The procurement process begins with an estimation of the fuel requirements on an annual, weekly, and daily basis. Contracts for ten to fifteen percent more volume than the anticipated need are entered into with various suppliers. The surplus volume is required in order to offset delivery disruptions due to inclement weather, mechanical breakdowns, or supplier interruptions. Wood continues to be procured in accordance with an agreement that existed between PSNH and the New Hampshire Timberland Owners Association (NHTOA) since the unit began operation. NHTOA and PSNH recently agreed to dissolve the agreement as PSNH consistently exceeded the standards outlined in the agreement. All wood must meet the NWP boiler specifications and permit obligations. All wood suppliers are required to enter into a purchase and sales contract with PSNH for the delivery of wood and every supplier is given a copy of the city of Portsmouth Truck Management Plan and a copy of the PSNH Random Vehicle Search Procedure.

**Biomass**

PSNH's newest fuel source, cocoa bean shells, is burned in combination with coal at Schiller Station. PSNH has received permits to be able to burn cocoa bean shells in both units 4 and 6. The cocoa bean shells are a byproduct of Lindt's manufacturing process at its nearby facility in Stratham. Lindt recently expanded its facility to incorporate the chocolate production process, which had previously taken place in Europe.

A test burn of cocoa shells occurred in March 2009 and demonstrated that a 30:1 blend of coal and cocoa shells can be successfully integrated in Schiller Station's existing coal boilers.

In January 2010, New Hampshire's Department of Environmental Services approved PSNH and Lindt's plan to incorporate cocoa bean shells as a supplementary fuel source at Schiller Station on a more permanent basis. This allows PSNH to replace a portion of coal with a portion of biomass. Every ton of cocoa bean shells used to generate electricity for PSNH customers will displace the need to burn one half-ton of coal.

The burning of biomass at Schiller Station reduces the amount of carbon dioxide ($CO_2$) that Schiller Station would otherwise emit through the burning of coal. That helps meet requirements of the Regional Greenhouse Gas Initiative (RGGI) to reduce $CO_2$ emissions from fossil-fuel power plants.

### B.5.1. Fuel Inventory Management

Fuel inventory levels at PSNH's electric generating stations are optimized between fuel supply reliability and carrying costs. The overriding goal is to maintain sufficient supply quantities on hand to meet anticipated generation needs at all times. Merrimack and Schiller Stations' minimum coal inventory levels are targeted to certain levels that are recommended by the New Hampshire PUC. The targeted levels are 45 days and 30 days supply, respectively, for Merrimack and Schiller. PSNH manages Merrimack Station's inventory level by coordinating 90-car train sets, and trucking foreign coal from the New

Hampshire coast out of Schiller Station's coal yard and continually projecting the station's capacity factor months in advance.

Ten to twenty days of full-burn equivalent of residual oil is maintained in inventory on-site at Newington Station.

### B.6. Supplemental Energy and Capacity Purchase Procurement Strategy

Section III described the process by which PSNH identifies a targeted set of block purchases to meet the hourly energy requirements for PSNH's default energy service customers. At present the principal driver is migration uncertainty. This section discusses the general process of procuring the targeted purchase quantities.

The decision to buy forward for a future period or to purchase from the spot market requires a qualitative assessment of a number of uncertain factors, including:

- Available market intelligence regarding anticipated commodity price movement
- Historical and expected spot market volatility within the future period
- Forecasted purchase requirement including migration uncertainty
- Risk-tolerance of the purchaser
- Availability of competitively priced supply options

Periodic meetings are held with PSNH's senior management to review all of these factors and to make decisions regarding how PSNH will supply default energy service requirements during upcoming periods. Such review includes discussions of whether to operate Newington Station or to purchase energy for particular months to replace Newington's output, and the amount and duration of purchases.

Fundamentally, the starting point for determining how much supplemental energy is needed to meet default energy service requirements is to compare the expected economic operation of PSNH's resources, including IPP purchases, to its forecasted default energy service energy needs. In PSNH's last plan, including its supplemental filings, the Company provided a narrative describing what it had previously done to meet its forecasted default energy service energy needs. In summary, the approach was to forecast need about a year ahead and to make a series of energy purchases to meet the forecasted need. The expectation was that a large portion of the next year's need would be bought and reflected in that year's default energy service price. Thus, assuming the sales forecast and migration levels throughout the subsequent year are as forecast, this strategy produces dollar cost averaged energy prices, and minimizes potential over / under recoveries. As noted in those very same filings, while descriptive of what had been done, PSNH was not bound to this approach and recognized the possibility of modifying how it sought to fulfill future needs. Furthermore, PSNH advanced its energy purchases such that a portion of future years' supplemental energy requirements were purchased earlier than had been done previously. In 2008 some purchases were made for periods as far out as 2011. This advanced energy purchasing strategy, like the year ahead energy purchasing strategy, was predicated on having a good estimate of migration and overall electricity sales levels.

Part way through 2008, commodity prices for gas and oil collapsed. Subsequently, starting very late in 2008 PSNH started to see migration from PSNH's Energy Service rate to third party suppliers. Migration continued in 2009 and into 2010. In addition, as discussed above, electricity usage also rapidly declined because of the recession. The combined effect of migration and the recession resulted in the energy sales forecasts originally used to model supplemental energy requirements for 2009 and 2010 to be too high.

As noted above, PSNH's default energy service cost structure favors modest to high gas prices which drive energy prices in New England, and/or high capacity prices; otherwise PSNH's default energy service price may not be attractive to all customer groups. The new paradigm of low gas prices may persist for the next few years while the country and state work their way out of the recession and demand for energy commodities rebuilds. Under these market conditions PSNH's continually evolving purchase strategy currently envisions looking at energy needs under a plausible high migration level when considering default energy service supplemental energy purchases prior to the start of the delivery period, and managing any remaining default energy service supplemental energy purchase needs through bilateral and ISO-New England administered energy markets during the delivery period.

In summary, the strongest motive behind PSNH's previous default energy service supplemental energy purchase strategy was to minimize over / under recoveries by locking in volumes and prices. However, the recession and recent migration drastically impacted PSNH's prediction about the volume and price of energy to be purchased, and brought to bear factors in addition to over / under recoveries, thus highlighting the need to dynamically respond to changing circumstances

If market conditions change again and PSNH is confident that its future needs are highly predictable it could move back to its earlier approach of locking in prices and volumes for upcoming periods.

The typical products that PSNH utilizes to serve the supplemental Energy Service energy requirement are:

1) **Fixed-price, forward bilateral contracts for "strips" of energy** (i.e., a uniform amount of energy in each hour of the relevant contract period). These are procured in on-peak strips (Non-holiday, Mon - Fri from hour-ending 8 am to 11pm), off-peak strips (all other hours), and weekend peak strips (Sat and Sun from hour-ending 8 am to 11pm). Typical contract duration ranges from a single day to multiple months. Monthly or multi-month contracts are typically procured from 3 to 12 or more months prior to contract delivery. Single day and weekly contracts are typically utilized to fine-tune the energy position and are procured within a few days of contract delivery.
2) **Unit–contingent forward bilateral contracts for energy** (i.e. purchase in whole or part a generating resource's energy production at a fixed or varying price). These arrangements can be of any duration but deliveries are typically around the clock whenever the resource generates.

PSNH does not have to hold in its name the amount of capacity it needs to serve default energy service customer requirements. Rather it is paid for the capacity it holds and pays for its share of capacity market costs resulting from serving default energy service customer load. The difference between the two is the supplemental capacity cost reflected in the default energy service rate. The goal of any hedging option would be convert the uncertainty of the market price into a known price for a given quantity. As of the writing of this plan capacity prices are known through May 2014. Given this pricing knowledge, and the fact that PSNH does not know what its default energy service requirements will be during the planning period, PSNH believes hedging capacity requirements at this time has no conceivable customer benefit. Thus, PSNH's supplemental capacity need will be addressed by simply paying for its net requirement at known capacity market prices.

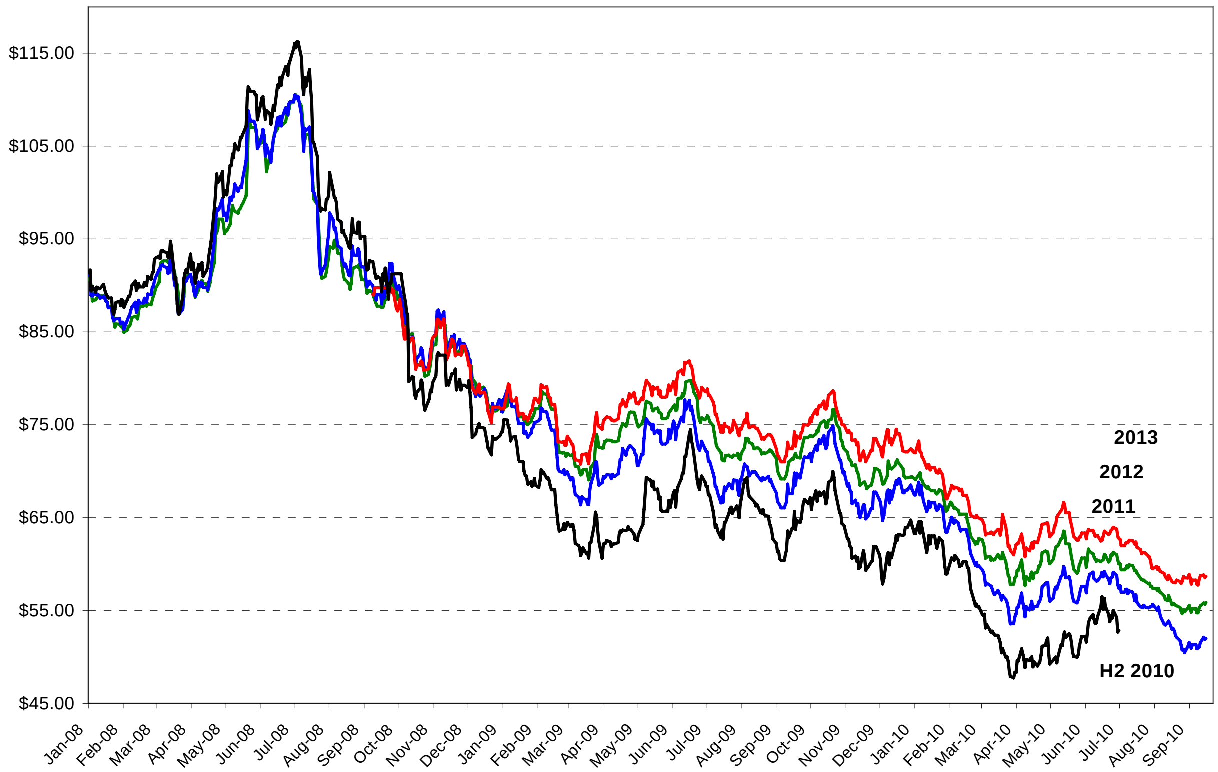
### B.6.1. PSNH's Hedging Strategy

As discussed above, PSNH does not have a prescribed hedging strategy (i.e., a plan that establishes specific dates, quantities, products, terms, etc.) and recognizes that not knowing a certain volume or price imparts some risk to default energy service customers, as does locking in firm supply at a fixed price prior to a delivery period. This dynamic necessitates a balance between forward and contemporaneous procurements. PSNH has the infrastructure, staff, and experience to enable a flexible approach to power supply planning. PSNH has retained over 1,100 MW of owned generation. PSNH submits daily generation offers and optimizes the dispatch of these assets within the ISO-New England markets. PSNH also analyzes the ISO-New England markets, interfaces with other market participants, is involved in numerous ISO-New England committees and task forces, reconciles settlement accounts with ISO-New England, and otherwise performs all the duties required to serve full requirements default energy service within the New England market structure. This is in contrast to numerous other distribution companies that have restructured, divested generation, and no longer have the appropriate staff to perform the functions of a load serving entity such as PSNH. Additionally, most or all of these distribution companies have specific solicitation schedules prescribed by the applicable regulatory agency.

PSNH is in a unique position that affords its customers numerous optimization tools that are not available to companies that are only permitted to procure full requirements service via wholesale solicitations from for-profit wholesale suppliers. To optimize the default energy service power supply, PSNH continuously forecasts, monitors, or makes adjustments for a number of critical factors, including operational and maintenance schedules at its generation facilities, fuel purchasing decisions, customer load forecasting, migration uncertainty, supplemental power purchasing decisions, and management of the renewable portfolio supply obligation. PSNH also must forecast and settle various ISO-New England administrative charges.

Up until recently, PSNH's supplemental energy purchase strategy to meet default energy service requirements was driven by minimizing over/under recoveries by locking up a large percentage of its default energy service requirements prior to setting default energy service rates. With migration becoming a larger variable in forecasting need, the volume of default energy service supplemental energy purchases has become more difficult to forecast. If migration is under forecast, PSNH will buy too much supplemental energy to meet default energy service requirements and will have to liquidate it at a price higher or lower than what it paid, thus creating an over/under recovery. If migration is over forecast, too little supplemental energy purchases will be made to meet default energy service requirements and an over/under recovery will result when the supplemental energy is purchased nearer to real time. Thus acting or not acting could produce over/under recoveries. Given the uncertainties surrounding customer migration and forward energy strip prices, delaying supplemental energy purchases perhaps even into the day-ahead or real-time ISO-New England energy markets, may be an attractive strategy at this time. Exhibit V-11 shows forward energy strip price trends since January, 2008, for calendar years 2010 through 2013.

**Exhibit V-11: Forward Energy Strip Price of On-Peak Power ($/MWH) - 2010, 2011, 2012 and 2013 for Jan 1, 2008 - Sep 15, 2010**




## B.7. New Generation Supply Options

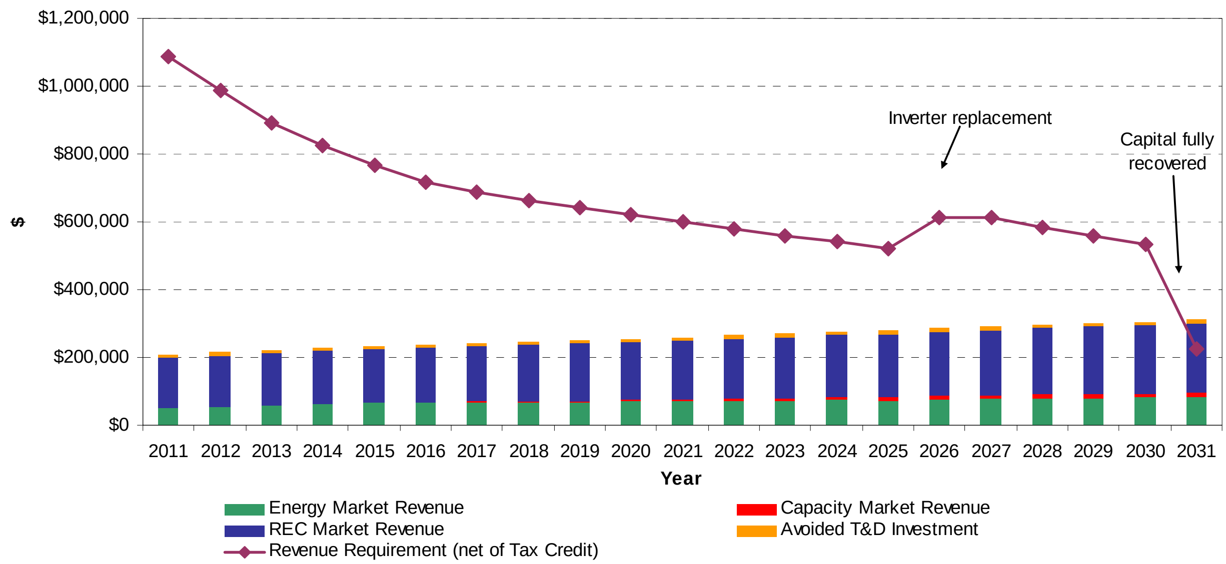
PSNH's delivery energy consumption is expected to grow about 0.4 percent per year while PSNH's system peak demand is expected to grow 3.4 percent per year over the planning period. In addition, the New Hampshire Renewable Portfolio Standard requires PSNH to supply a portion of its customers' default energy service energy requirements from renewable sources and the percentage of renewable sources increases over time through 2025. PSNH owned generation resources are presently fixed due to State policy restrictions on the expansion of utility-owned generation resources and expiring purchased power contracts. PSNH currently supplies 80 to 90 percent of its customers' default energy service energy requirements with its own and contracted generation supply sources. As a result of reduced consumption, increased migration, and increased conservation efforts, PSNH does not propose adding any significant new generation to its portfolio to serve customer load over the five year planning horizon. This is markedly different from the LCIRP filed in 2007 which shows how much the energy markets have changed in recent years.

To meet the projected energy requirements, PSNH will need to purchase anywhere from 0 to over 3 million MWh per year in the open market and up to 1,000 MW per year of capacity either in the ISO-New England Forward Capacity Market over the planning period, depending on the level of customer migration and energy consumption experienced. Additionally, PSNH will be increasingly short of supply of certain classes of RECs to meet New Hampshire's Renewable Portfolio Standard requirements and will be required to either purchase RECs from qualified facilities or make Alternative Compliance Payments to the state for the renewable resource deficiency. See section X for a more detailed discussion of PSNH's compliance with the New Hampshire Renewable Portfolio Standard.

In PSNH's previous LCIRP filing, several resource types were proposed as a way to fill the gap between owned or contracted supply resources and customers' default energy service requirements. Given PSNH's current gap at the 31 percent migration level, the Company is not proposing any additional supply resources except for small scale renewable distributed generation resources, if found to be economic.

Exhibit V-12 graphically shows the comparison of the revenue requirement (net of tax credits) compared to the benefits received from the energy, capacity, and REC markets for a generic 1 MW ground mounted solar photovoltaic project. Revenue requirements include ongoing operating and maintenance expenses, return of the capital for the asset and return on the capital for asset. The offsetting revenues include ISO-New England Forward Capacity Market revenue, energy market revenue, and Class II RPS revenue that the project would receive from its energy and capacity output. These benefits would offset the revenue requirement paid by customers. As can be seen in this exhibit, the costs of solar PV are much higher than the benefits until the capital cost of the project is fully recovered. After that time, because the fuel source is free, the annual benefit to customers is positive. Absent significant changes in capital costs and energy market prices, or an increase in state or federal subsidies for REC-producing solar facilities, it is unlikely that New Hampshire will meet its class II solar RPS requirements.

**Exhibit V-12: Example 1 MW Distributed Solar PV Project (Ground Mounted) Revenue Requirement and Benefits**




PSNH will pursue these opportunities as supplemental funding sources and optimal solar locations are presented. If an opportunity arises, PSNH will present the distributed generation project to the Commission under RSA 374-G.

## VI. Assessment of Transmission Requirements

Attached is PSNH's Transmission Plan. PSNH's Transmission Plan is filed on a biennial basis to the New Hampshire Public Utilities Commission. PSNH's Transmission Plan was updated for this LCIRP filing.

# Public Service of New Hampshire Transmission Plan

**Saco Valley Substation Phase Shifting Transformer**

## September 30, 2010

Public Service of New Hampshire
The Northeast Utilities System

# TABLE OF CONTENTS

# EXECUTIVE SUMMARY

## A Continuing Responsibility to Ensure Electric Delivery System Reliability

Public Service Company of New Hampshire ("PSNH" or "the Company") is an electric utility that serves more than four-hundred and ninety thousand homes and businesses in New Hampshire. PSNH's primary responsibilities include the provision of safe and reliable electric delivery service to our customers. In order to ensure reliable electric service, PSNH monitors system loads and works within the Independent System Operator New England, Inc. ("ISO-NE") transmission planning process to plan system modifications and new facilities needed to reliably meet its load serving requirements.

PSNH is filing its 2010 Transmission Plan pursuant to RSA 378:38, which requires each electric utility to file a transmission plan with the New Hampshire Public Utilities Commission ("NHPUC").

Transmission systems transport power from generation sites to the local "neighborhood" systems that distribute power to residences, businesses, and communities. PSNH's transmission system serves an important role in ensuring electric service reliability, and it must be robust and flexible enough to accommodate an ever-changing generation marketplace. This transmission system also has a critical supporting role in the economic growth of New Hampshire and the New England region by providing access to diverse, competitively-priced, and environmentally beneficial electrical energy resources. It is the crucial link between power generation and New Hampshire consumers. PSNH is investing in New Hampshire's future by strengthening the regional transmission infrastructure.

PSNH foresees that the transmission system is facing several challenges over the next ten years:

- PSNH is performing studies to connect new renewable generation resources to the electric grid and upgrade the transmission delivery system. PSNH is working with the State of New Hampshire, ISO-NE , interested state parties, and regional stakeholders to identify the needs and interconnection solutions for new renewable and other generation resources
- PSNH must comply with mandatory reliability standards as established by the North American Electric Reliability Corporation ("NERC") and approved by FERC as a result of the Energy Policy Act of 2005.
- PSNH is performing studies to analyze the performance of its transmission network to reliably and economically serve growing electric load demands. PSNH will need to strengthen and upgrade its transmission system and build new facilities to resolve electric delivery requirements.

# Chapter 1: INTRODUCTION

## 1.1 Report Overview

In this report, PSNH presents and discusses the following:

- The forecast of peak demands for electricity.
- Load areas in New Hampshire currently under evaluation.

PSNH presents tables listing proposed modifications and new facilities to its transmission system through the planning period.

## 1.2 Planning Principles

The key principle of transmission planning is to have a known and measurable plan to reliably meet future peak demands for electricity. New investments in transmission facilities ensure the continuance of a reliable and dependable electric system to support the expansion of the New Hampshire economy.

Planned transmission facilities generally serve at least one of the following purposes:

1) To reliably serve customers' peak demands for electricity.

2) To maintain system reliability under varying generator dispatch scenarios.

3) Interconnect new generation resources.

4) To provide transmission transfer capability on a regional basis.

5) To resolve system reliability and safety concerns of high short-circuit currents.

The PSNH and ISO-NE planning processes employ similar methodologies with respect to the identification of system needs, the consideration and evaluation of multiple alternatives and the final development of a recommended plan. PSNH, through extensive coordination efforts with ISO-NE, effectively integrates its planning functions with other regional entities including neighboring electric systems. Therefore, PSNH's planning process is coordinated with the ISO-NE regional planning process. This coordination continuously reflects the changing environment with respect to transmission service, in order to ensure efficient and reliable transfer of electric energy that serves the needs of the local delivery systems while enhancing the capabilities of the transmission grid on a regional basis.

# Chapter 2: LOAD FORECAST AND GENERATION SUPPLY

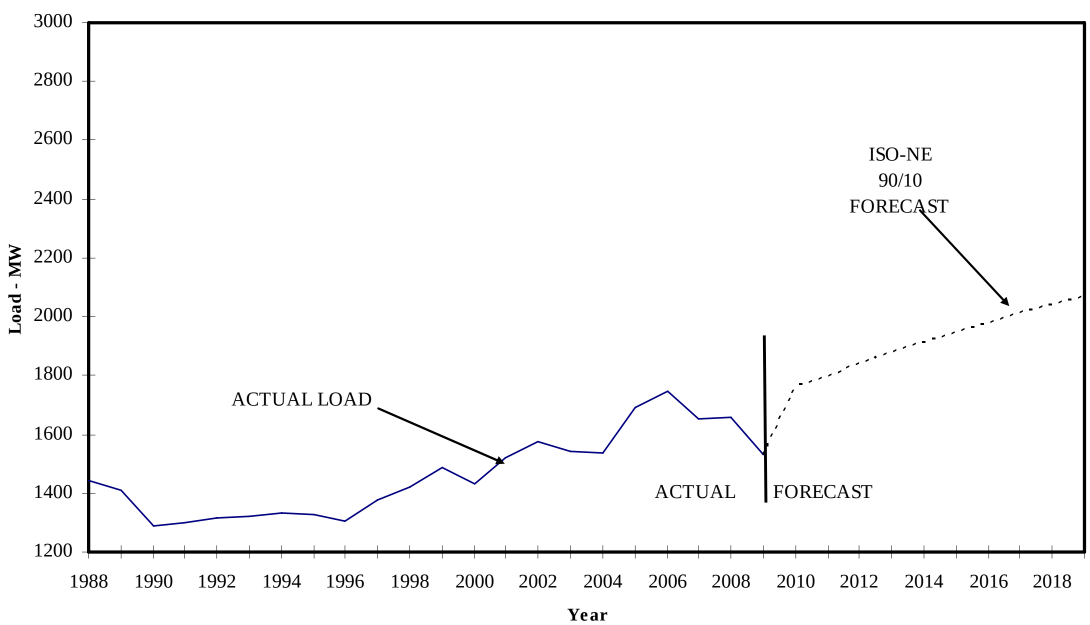
## 2.1 ISO-NE Load Forecast

ISO-NE in conjunction with PSNH and other transmission owners develops annual forecasts of peak loads for each New England state. The load data is contained in the annual filing of the ISO-NE Forecast Report of Capacity, Energy, Loads and Transmission ("CELT") report and in the ISO-NE Regional System Plan ("RSP").

ISO-NE and transmission owners use a planning approach which provides more certainty of ensuring a transmission system capable of providing reliable electric service even under the most severe weather conditions.

New England utilities use a 90/10 demand forecast developed by ISO-NE for transmission planning purposes. This forecast assumes that the actual peak load has a 10% chance of exceeding the 90/10 forecasted load level. Chart 2-1 contains the ISO-NE 2010 CELT report peak-demand forecast data for PSNH that is used as input in New England power flow models.

**Chart 2-1**
**ISO-NE Demand Forecast for PSNH**
**Summer Peak**





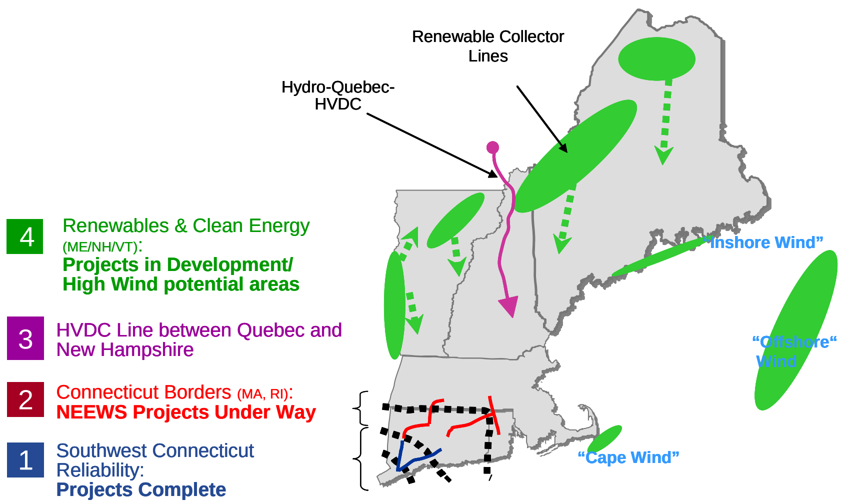

000111

## 2.2 Incorporation of Renewable Energy through Transmission

Transmission has an essential role to play in providing access to remote renewable electric energy resources. Renewable resources like wind and hydro power will likely not be sited close to load centers, so transmission will be needed to move this energy to the load. The prospect of transporting renewable energy from northern New England and Canada is particularly promising.

The availability of generation capabilities for transmission planning purposes is obtained from the most recent issue of the ISO-NE CELT report, RSP09 and from the ISO-NE generation interconnection queue. Generation additions and known retirements are analyzed to determine their impact on transmission system reliability. Various generation dispatch scenarios are used as input into power flow models of PSNH's electrical system.

Long-term forecasts show surplus renewable/low carbon generation in the eastern provinces of Canada and insufficient renewable /low carbon generation in Ontario, New York, and New England. Strengthening New Hampshire's transmission interconnection with the rest of New England will give the state the opportunity to share in the region's access to Canada's projected surplus power. Northeast Utilities ("NU") has studied various options and has proposed a high-voltage direct current transmission tie line with Hydro Quebec.






000112

# Chapter 3: TRANSMISSION PLANNING

## 3.1 Transmission Planning In A Restructured Electric Market

The introduction of competition into the previously integrated electric industry altered the focus of transmission system planning. Local transmission systems built in the past to serve customer load from generation within a limited geographic area are now expected to serve the same customer load from remote generation. Transmission systems must now be able to operate reliably with less reliance on local generation.

In 2001, FERC required the New England Power Pool ("NEPOOL") to cede responsibility for the system planning process of the bulk power system to ISO-NE. As the regional transmission organization ("RTO"), ISO-NE is now responsible for transmission planning of the bulk power system in New England. Pursuant to the regional system planning process in the ISO-NE Transmission, Markets & Services Tariff, ISO-NE determines system reliability and market efficiency needs and approves regulated transmission plans.

Under the RTO structure, ISO-NE identifies, through a system needs assessment process, New England reliability problems. ISO-NE solicits alternative solutions to these reliability problems. Finally, ISO-NE will determine which transmission projects will address system reliability needs that are not resolved by market responses. Through this planning process ISO-NE is responsible for developing and maintaining a transmission plan on a coordinated regional basis. The annual RSP that is approved by the ISO-NE's Board of Directors encourages the development of generation and transmission facilities that ensure the reliability of the New England bulk power system, taking into account load growth and known resource changes.

In addition to assessing the amount of resources needed by the overall system and individual sub areas of the system, the planning process assesses the types of resources that can satisfy these needs and any critical time constraints for addressing them. Thus, the RSP specifies the characteristics of the physical solutions that can meet the defined needs and includes information on market solutions to address them. Market participants can then use this information to develop the most efficient solutions, such as investments in merchant generation, demand-side projects, distributed generation, and merchant transmission. If the market responses fall short of meeting these needs, or if additional transmission infrastructure is required to facilitate the market, the RSP must also identify a regulated transmission solution.

RSPs must account for the uncertainty in assumptions about the next 10 years considering changing demand, fuel prices, technologies, market rules, environmental requirements; other relevant events; and the physical conditions under which the system might be operating. In addition, ISO-NE must also coordinate study efforts with surrounding RTOs and control area and analyze information and data presented in neighboring plans, to develop the RSP. Each report must also provide the status of proposed and ongoing transmission upgrades and justify any newly proposed transmission improvements.

RSPs must comply with NERC and NPCC criteria and standards and ISO-NE Planning and operating procedures. The RSPs must also conform to transmission owner local criteria.

Transmission system planning is now more complex than prior to electric industry restructuring as plans must consider generation market variables that include, deactivations or retirements of aging generators, and potential for retirements of generators due to environmental or economic reasons.

The transmission planning process must be dynamic and sufficiently flexible to incorporate these factors to meet increasing demands to transfer power from remote resources to load centers. Maintaining the reliability of the transmission system is necessary to ensure a robust competitive marketplace for electricity, satisfy customer demands for electricity and expectations with regard to service reliability, and protect the health, welfare and safety of the public.

In the March 15, 2007 Order No. 890, "Preventing Undue Discrimination and Preference in Transmission Service," FERC has required greater transparency and openness in the transmission planning process, and has directed all transmission providers to develop a transmission planning process that satisfies nine principles, to be incorporated in a new Attachment K to their open access transmission tariffs. These principles include coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation. As a result, ISO-NE is working with the New England transmission owners and other stakeholders to ensure that the existing, already robust transmission planning process meets these principles and addresses any areas of FERC concern.

## 3.2 Mandatory National Reliability Standards

The New Hampshire transmission system is part of the larger New England regional grid and thus subject to the interdependencies of generation, load and transmission in neighboring electric systems. NERC recognizes that the actual planning and construction of new transmission facilities has become more complex.

The Federal Energy Policy Act of 2005 required FERC to designate an entity to provide for a system of mandatory, enforceable reliability standards under FERC's oversight. This action is part of a transition from a voluntary to a mandatory system of reliability standards for the bulk-power system. In July 2006, FERC designated NERC as the nation's Electric Reliability Organization ("ERO"). The ERO is to improve the reliability of the bulk-power system by proactively preventing situations that can lead to blackouts, such as that which occurred in August 2003.

On March 15, 2007, FERC approved mandatory reliability standards developed by NERC. FERC believes these standards will form the basis to maintain and improve the reliability of the North American bulk power system. These mandatory reliability standards apply to users, owners and operators of the bulk power system, as designated by NERC through its compliance registry procedures. Both monetary and non-monetary penalties may be imposed for violations of the standards. The final rule, "Mandatory Reliability Standards for the Bulk Power System," became effective on June 18, 2007.

Currently PSNH follows the requirements of TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0 standards (i.e., NERC Categories A, B, C and D) when planning its electric power systems in New Hampshire. ISO-NE Planning Procedure No. 3 ***"Reliability Standards for the New England Area Bulk Power Supply System"*** (ISO-NE PP3) and NPCC Regional Reliability Reference Directory #1, ***"Design and Operation of the Bulk Power System"*** are also used by PSNH.

At present NERC has proposed to replace all four TPLs (i.e., TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0) and two additional standards (TPL-005-0 and TPL-006-0) with a single standard (TPL-001-1). The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

# Chapter 4: TRANSMISSION SYSTEM BACKGROUND

## 4.1 Background on PSNH's Transmission System

Transmission lines collectively form the infrastructure that is an interstate electric "highway system," moving electric energy from where it is produced to where it is used. In New England, moving electric energy is achieved primarily by the interconnected 345-kV regional bulk power system. The 345-kV transmission ties to neighboring utilities and control areas and expansion of the high voltage networks enables PSNH to meet its customers' peak demands for electricity. Operating this system at 345 kV allows for the efficient transfer of bulk power within and outside of the New Hampshire area. This integrated grid enables PSNH to efficiently transmit power throughout its franchise service territory and share in the reliability benefits of parallel transmission paths to neighboring electric systems.

The total mileage of PSNH's existing transmission circuits in New Hampshire is comprised of:

- 252 circuit-miles of 345-kV lines
- 9 circuit-miles of 230-kV lines
- 738 circuit-miles of 115-kV lines

## 4.2 Transmission System

PSNH's transmission system is part of the interconnected New England transmission network. Transmission lines across the New England region and outside of the region are interconnected to form a transmission network, sometimes called a "grid" or "system." The transmission grid serves multiple purposes, all of which work together to enhance reliability. PSNH, ISO-NE and other electric utilities design the transmission grid to meet federal, regional and company reliability criteria. ISO-NE operates the system as one integrated network in order to provide reliable and economic delivery of energy throughout the region.

PSNH's electrical network, with its tie lines to neighboring utilities, provides a path that allows power to move freely within and over the New England transmission system. This means power can flow in any direction, depending on generation dispatch and load patterns and the configuration of the transmission system. PSNH's electrical network, in combination with tie lines to neighboring electric systems enables PSNH to rely on import capabilities. The interconnected transmission tie lines provide both PSNH and neighboring systems access to economic generation and increased reliability during emergencies.

PSNH's electrical network is composed of 345-kV and 230-kV high voltage transmission lines interconnecting with high voltage systems, principally 115 kV, to serve both a sub-area transmission function and an intra-regional function. At numerous substation locations on the network, voltage transformation is performed to enable the efficient delivery of power to area load centers. There are four major bulk power substations that tap the 345-kV and 230-kV transmission networks: the Scobie Pond and Deerfield Substations transform voltage from 345 kV to 115 kV, and the Littleton and Merrimack Substations transform voltage from 230 kV to 115 kV. Tapped at numerous locations are step-down substations for local distribution that transform voltages from either 345 kV or 115 kV to 34.5 kV and below.

Generating stations are interconnected at various voltages. Large central generating stations, such as PSNH 's Newington Station, North American Energy Alliance's

("NAEA") Newington Energy Station and NextEra's Seabrook Station, are connected to the 345-kV transmission system. Other generating stations, like Merrimack, Schiller and Granite Ridge (only the steam generator), connect to the 115-kV system. Smaller PSNH generators and non-utility owned generating units are distributed throughout the state on the electrical network. These units typically connect to the 34.5-kV distribution system.

### 4.2.1 345-kV and 230-kV Systems

The PSNH 345-kV and 230-kV systems connect New Hampshire to Maine, Vermont and Massachusetts. These facilities are part of the New England bulk power transmission system. These systems, generally located across the southern part of New Hampshire, transmit power from large central generating stations like PSNH Newington, NAEA Newington and Seabrook to eight extra high voltage ties with neighboring utilities and eight step-down substations feeding the loads of PSNH and Unitil Corporation. Typically, a single 345-kV transmission line can carry over 1,000 MW of electric power.

The Deerfield and Scobie Pond 345-kV substations contain circuit breakers that interconnect several 345-kV transmission lines. The electrical configuration of these substations allow for certain elements to be out of service while maintaining the integrated nature of the substation design. Currently the Deerfield Substation contains one 450 MVA autotransformer and the Scobie Pond Substation contains three 450 MVA autotransformers that transforms voltage from 345 kV to 115 kV.

The two 230-kV lines owned by National Grid, running approximately the entire length of New Hampshire, were primarily built to bring hydro generation from the north to Massachusetts. The Merrimack and Littleton 230-kV substations tap these transmission lines. The Merrimack Substation contains a single 400 MVA autotransformer and the Littleton Substation contains a single 200 MVA autotransformer that each transforms voltage from 230 kV to 115 kV.

Operating these systems at 345 kV and 230 kV allows for the efficient transfer of bulk power within and outside of the New England area. This enables PSNH to attain maximum practicable economy in bulk power supply and share in the reliability benefits of parallel transmission paths.

Since the last filing in 2007, the following projects have been placed in service:

1. Fitzwilliam 345/115-kV Substation and autotransformer addition.
2. Installation of a third 345/115-kV autotransformer at Scobie Pond Substation.

### 4.2.2 115-kV System

The 115-kV transmission system is the "backbone" of PSNH's local electric network serving distribution substations. This system loops around high load density areas in southeastern New Hampshire with ties into the western and central part of the state. The major north-south 115-kV line through New Hampshire ties the 230-kV tap in Littleton to the 115-kV loop in the south. Along this transmission corridor are east-west 115-kV taps to serve load centers throughout central New Hampshire. The Saco Valley Phase Shifter which was placed in service in 2009 as part of the Closing the Y138 project, provides the ability to control the flow of power from northwestern Maine to New Hampshire. A 115-kV transmission line, depending on conductor size, can carry between 100 MW and 300 MW of electric power.

The 115-kV system transmits power from central generating stations like Merrimack, Schiller and Granite Ridge, 115-kV tie lines to neighboring utilities and 115-kV taps to distribution step-down substations for local area supply.

# Chapter 5: TRANSMISSION SYSTEM NEEDS

PSNH's 2010 transmission plan includes the monitoring of demands for electricity and system conditions, planning for system needs and reliability and constructing upgraded or new facilities as required. This three part plan is as follows:

1. Monitor load growth projections for New Hampshire, which include PSNH, the New Hampshire Electric Cooperative, New Hampton, Ashland, Wolfeboro and Unitil Corporation. Load growth is a primary driver for the need to install new transmission facilities. Regional power transfers based on generation dispatch assumptions will also play a key role in determining the need to build new facilities. The accurate modeling and forecasting techniques support the timing of transmission expansion and ensure full utilization of existing facilities.

2. Plan transmission line and substation facility upgrades and new facilities to meet forecasted needs.

3. Construct transmission facilities that are required to meet reliability needs, reduce congestion on the grid and connect new generation to PSNH's transmission system.

The three functions above are the core of PSNH's transmission plan. The plan includes a process to monitor and change transmission plans as customer needs vary. The plan is dynamic and recognizes the ever-changing customer demands for electricity and the market for new sources of reliable and economic generation. This plan in part identifies new transmission facilities that must be installed for PSNH to reliably serve increasing customer demands for electricity.

A 10-year study is currently in progress with Vermont Electric Power Company ("VELCO"), National Grid, and ISO-NE to evaluate and address long term reliability concerns in the New Hampshire and Vermont areas. Initial power flow results show a potential inter-area reliability problem. A new 345-kV circuit between New Hampshire and Vermont could address the reliability concern. One of the alternatives under evaluation is a potential 345-kV transmission line from the Deerfield Substation in New Hampshire to the Coolidge Substation in Vermont.

## 5.1 Seacoast Area

The Seacoast Area stretches from Rochester, Dover, Portsmouth, to Hampton and Exeter. This area contains approximately 25% of the electric demand in New Hampshire. The Seacoast Area contains 345-kV and 115-kV transmission facilities. However, this area does not have a direct connection between the 345-kV and 115-kV voltage levels. The metropolitan areas of Dover, Portsmouth and Rochester are primarily served by the 115-kV transmission system. The 115-kV system integrates Schiller Station, tie lines from Maine and transmission lines from the Scobie and Deerfield substations to serve the electrical demands of this area. This area is supported by ties to the 345-kV bulk power system through 345/34.5-kV distribution step-down transformers.

Heavy power flows on the transmission line corridor between the Scobie and Schiller Substations is a result of significant load growth in the Seacoast area and along the Rt. 101 corridor. This area is served from the Scobie Substation by relatively lower-capacity transmission lines (R193, B172, H141, S153, E194, and U181). Several 115/34.5-kV existing and recently constructed distribution substations are connected to these lines. In addition, during peak demand periods, power transfers from Maine with Schiller generation off-line can cause power flow to exceed equipment ratings along this path.

PSNH is investigating the feasibility and system benefits of installing 345/115-kV autotransformers in the vicinity of the Newington Substation. An autotransformer interconnection in the Seacoast area would tap generation resources on the 345-kV system at Newington and Seabrook, provide increased voltage regulation, and eliminate thermal overloads by reducing power transfers on the 115-kV transmission lines from Scobie and Deerfield. As part of this evaluation and alternative analysis PSNH is considering the benefits of rebuilding these 115-kV transmission lines in part or whole to support power flows and voltage profiles in the Seacoast area.

Transmission lines and substation facilities are also required to connect new distribution step-down transformers to the transmission system in the Seacoast area. PSNH is currently planning new 115/34.5-kV transformer addition and construction of a new 115-kV line in the Rochester area.

This area currently has several projects that are active, under consideration or in the planning stages. See Tables 6-1, 6-2 and 6-3.

## 5.2 Southern Area

The Southern Area stretches from Concord, Manchester, and Derry to Nashua. This area contains approximately 50% of the electric demand in New Hampshire. The Southern Area is the largest in New Hampshire. The area is dependent on internal generation and 345-kV transformation capabilities coupled with 115-kV tie line support from neighboring utilities. The interconnection of large generating plants and transmission play a vital role in serving the metropolitan areas of Concord, Manchester and Nashua. The 115-kV transmission lines in this area integrate the generation at Merrimack and Londonderry with local load centers. The area is supported by ties to the 345-kV bulk power system through 345/115-kV autotransformers or 345/34.5-kV distribution step-down transformers.

Thermal loading on transmission facilities in this area is the most pressing reliability concern during high load periods. Contingency thermal loading on transmission facilities are above emergency ratings or system voltages may fall below acceptable limits following the loss of the Scobie Pond or Deerfield 345/115-kV autotransformer. This also stresses import capabilities from neighboring electric systems. Currently, PSNH is planning the addition of a second 345/115-kV autotransformer at Deerfield Substation to be installed in 2012. In addition, this plan includes upgrading several 115-kV lines (L175, M183 and C129).

The Nashua area is served by two 115-kV transmission lines from the north originating at PSNH's Greggs and Scobie Substations. A single 115-kV line connects the Nashua area with the National Grid system in Pelham. In addition, two distribution substations tied to the 345-kV network at Amherst and Lawrence Road also serve the area's load. PSNH maintains a balance between power transfers on the 115-kV system and load serving capabilities of the 34.5-kV system at the Amherst and Lawrence Road Substations.
The forecasted demand for electricity in the Nashua area stresses the existing system's capabilities. PSNH is evaluating the need for additional 345/115-kV transformation in the Nashua/Milford area or at the Scobie Substation to support increased transmission power flow requirements. The interconnection of an autotransformer into the transmission system in this area may require additional 115-kV transmission facilities to be constructed.

Transmission lines and substation facilities are also required to connect new distribution step-down transformers to the transmission system in the Southern area. PSNH is currently planning new transformer additions in the Manchester, Merrimack, Londonderry, Nashua, Chester areas. Depending on the location of new 115/34.5-kV substations, reconfiguration of the existing transmission system or construction of new 115-kV transmission lines may be required.

A 10-year study is currently in progress with NSTAR, National Grid, and ISO-NE to evaluate and address long term reliability concerns in the Greater Boston area. One of the alternatives under evaluation is a potential 345-kV transmission line from the Scobie Pond Substation in New Hampshire to the Tewksbury Substation in Massachusetts.

This area currently has several projects that are active, under consideration or in the planning stages. See Tables 6-1, 6-2 and 6-3.

## 5.3 Western Area

The Western Area stretches from Hillsborough to Keene to the Vermont border. This area contains approximately 10% of the electric demand in New Hampshire. The Western area has lower-capacity 115-kV tie-lines and is very dependent on the 345/115-kV Vermont Yankee Substation. In 2009, a new 345/115-kV transmission substation in Fitzwilliam was placed in service

Increased power transfers in this area will continue to strain other PSNH transmission lines. PSNH is evaluating the need to upgrade the 115-kV Keene – Monadnock T198, Chesnut Hill- Wesport-Swanzey A152, and Jackman - Keene L163 transmission lines.

Transmission lines and substation facilities are also required to connect new distribution step-down transformers to the transmission system in the Western area. PSNH is currently planning new transformer additions in the Keene, Hinsdale, Westport, Hillsboro and Swanzey areas. Depending on the location of new 115/34.5-kV substations, reconfiguration of the existing transmission system or construction of new 115-kV transmission lines may be required.

This area currently has several projects that are active, under consideration or in the planning stages. See Tables 6-1, 6-2 and 6-3.

## 5.4 Central Area

The Central Area or Lakes Region stretches from Sunapee and Laconia to the Mount Washington area. This area contains approximately 10% of the electric demand in New Hampshire. This area relies almost entirely upon power transfers from resources outside the area.

PSNH is evaluating the reliability of the 115-kV transmission system that feeds into the northwest part of the Lakes Region. Depending on load and system conditions, the outage of transmission facilities in the northern area at the Littleton Substation (Littleton 230/115-kV autotransformer and the 115-kV Littleton - Whitefield - Beebe X178 line) may cause interruptions to PSNH loads. Of particular concern is the long-term outage of the Littleton 230/115-kV autotransformer. Loss of the Littleton autotransformer disconnects the central area from its strongest tie to the Comerford Substation. Under this condition the entire central area is served by three weak ties: 1) Moore 230/13.8-kV transformer; 2) Webster north: and the 3) 115-kV Littleton - St Johnsbury 60 line in Vermont. System voltages under contingency conditions can fall below acceptable limits and could result in voltage collapse. In addition to low voltage conditions, this contingency may cause high power flow through the Moore 230/13.8-kV transformer that could exceed its emergency ratings.

The 115-kV Littleton - Whitefield - Beebe X178/U199 line is approximately 60 miles long through the mountainous areas of northern New Hampshire. The 115-kV line connects the Littleton Substation to the central area loads through the Beebe Substation. An outage of the X178 line disconnects the entire central area from the Littleton Substation. In 2008, PSNH closed the 115-kV White Lake- Saco Valley Y138 line to support reliable electric service to the White Lake and Saco Valley substations and to the entire Central and Northern areas of the PSNH transmission system.

Transmission lines and substation facilities are also required to connect new distribution step-down transformers to the transmission system in the Central area. PSNH is currently planning new transformer additions in the White Lake area. Depending on the location of new 115/34.5-kV substations, reconfiguration of the existing transmission system or construction of new 115-kV transmission lines may be required.

In addition, PSNH recognizes the future need to reinforce the central New Hampshire region by considering the construction of 345-kV facilities emanating from the Deerfield Substation into this area and potentially beyond the area to northern New Hampshire and/or into Vermont.

This area currently has several projects that are active, under consideration or in the planning stages. See Tables 6-1, 6-2 and 6-3.

## 5.5 Northern Area

Northern New Hampshire includes the areas of Berlin, Groveton, Lincoln and Whitefield. This area contains approximately 5% of the customer demand in New Hampshire. This area is fed from the 115-kV tie lines to the National Grid system and a 115 kV intra-company line from the central region. Local generation can also support load area load demands.

Currently there are a total of over 400 MW of wind and biomass facilities in the ISO-NE Interconnection Queue with applications to connect to the northern New Hampshire system. Approximately 100 MW have received approval in accordance with Section I.3.9 of the ISO Tariff that the Applicant's proposed plan will not have a significant adverse impact on the New England Transmission System; with another 90 MW currently being reviewed by ISO-NE. To interconnect all 400 MW, additional transmission upgrades will be required.

The North Country Transmission Commission ("NCTC"), created by the New Hampshire Legislature (2008 N.H. Laws, Chapter 348), has hired a consultant to recommend options to pay for this transmission. The consultant's final report will be presented to the NCTC on October 1, 2010. The NCTC will make its report to the New Hampshire Legislature in December 2010.

This area currently has one project that is active, under consideration or in the planning stages. See Tables 6-1, 6-2 and 6-3.

## Chapter 6: THE NEW HAMPSHIRE TRANSMISSION PLAN

This section contains a summary of transmission modifications or additions to the New Hampshire electric system. Certain distribution substations are identified in the tables that require transmission facilities to connect the substation to the transmission network.

The tables attached contain a listing of transmission projects. Tables 6-1 through 6-3 are summarized below. During the forecast period, additional transmission projects beyond those listed may be justifiable to enhance reliability or provide efficient means to transmit electric energy. The estimated in-service dates for new facilities listed below may vary through time as the dynamics of the system change.

Attachment I Transmission Project Listing

**Table 6-1**, Transmission Lines Under Construction.

**Table 6-2**, Transmission Lines Under Planning Consideration.

**Table 6-3**, Substation Projects – Rated 115-kV and Above.

**Attachment I**
**Table 6-1**
**Transmission Lines Under Construction**

| From | | To | | | | | Length | | |
|---|---|---|---|---|---|---|---|---|---|
| Substation | City or Town | Substation | City or Town | Line Number | Area | Voltage kV | of Circuit (miles) | Project Type | Proposed ISD |
| Deerfield | Deerfield | Madbury | Madbury | L175 | Southern | 115 | 13 | Rebuild | 2011 |
| Madbury | Madbury | Rochester | Rochester | C129 | Southern | 115 | 20 | Reconductor | 2011 |
| * North Rochester | Rochester | Easport | Milton | Y170 | Seacoast | 115 | 7 | New Line | 2015 |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |

*Although listed under this table, this project is only in the design phase.

**Attachment I**
**Table 6-2**
**Transmission Lines Under Planning Consideration**

| From | | To | | Line Number | Area | Voltage kV | Length of Circuit (miles) | Project Type | Proposed ISD |
|---|---|---|---|---|---|---|---|---|---|
| Substation | City or Town | Substation | City or Town | | | | | | |
| Chester | Chester | Great Bay | Stratham | H141 | Seacoast | 115 | 19 | Reconductor | Under Review |
| Scobie Pond | Londonderry | Chester | Chester | B172 | Southern | 115 | 6 | Reconductor | Under Review |
| Scobie Pond | Londonderry | Kingston | Kingston | R193 | Southern | 115 | 11 | Reconductor | Under Review |
| Deerfield | Deerfield | Pine Hill | Hooksett | D118 | Southern | 115 | 16 | Reconductor | Under Review |
| Power Street | Hudson | Dracut | Dracut | Y151 | Southern | 115 | 7 | Reconductor | Under Review |
| Jackman | Hillsboro | Keene | Keene | L163 | Western | 115 | 26 | Rebuild | Under Review |
| Chesnut hill | Hinsdale | Westport | Winchester | A152 | Western | 115 | 12 | Rebuild | Under Review |
| Keene | Keene | Monadnock | Troy | T198 | Western | 115 | 11 | Rebuild | Under Review |
| Scobie Pond | Londonderry | Tewksbury | Tewksbury, MA | TBD | Southern | 345 | 24 | New Line | Under Review |

**Attachment I**
**Table 6-3**
**Substation Projects - Rated 115 kV and Above**

| Substation | City or Town | Area | Voltage (kV) | Project Type | Proposed ISD |
|---|---|---|---|---|---|
| Scobie Pond | Londonderry | Southern | 115/12.5 | Transformation Interconnection | 2011 |
| Deerfield | Deerfield | Southern | 345/115 | Add Autotransformer | 2012 |
| Eagle | Merrimack | Southern | 115/34.5 | Transformation Interconnection | 2012 |
| Kingston | Kingston | Seacoast | 115/34.5 | Transformation Interconnection | 2012 |
| Broad Street | Nashua | Southern | 115/34.5 | New Substation | 2012 |
| Eastport | Rochester | Seacoast | 115 | New Substation | 2014 |
| North Rochester | Milton | Seacoast | 115/34.5 | New Substation | 2015 |
| Littleton | Littleton | Northern | 230/115 | Add Autotransformer | TBD |
| Saco Valley | Conway | Central | 115 | Add Capacitor | TBD |
| Webster | Franklin | Central | 115 | Add Capacitor | TBD |
| Chester | Chester | Seacoast | 115 | Add Capacitor | TBD |
| Gosling | Newington | Seacoast | 345/115 | New Substation | TBD |
| Deerfield | Deerfield | Southern | 345/115 | Add Autotransformer | TBD |
| Scobie Pond | Londonderry | Southern | 345/115 | Add Autransformer | TBD |

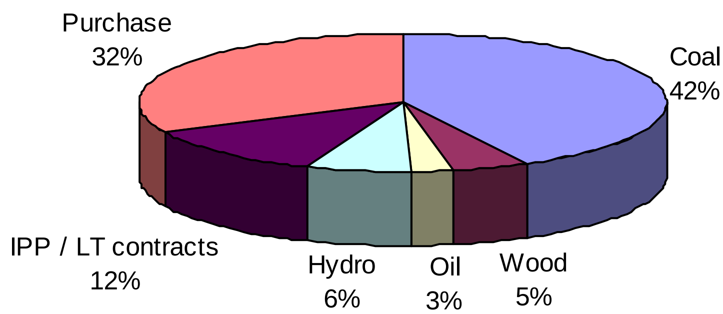
# VII. Provision for Diversity of Supply Sources

This section discusses the diversity of PSNH's supply sources, its mandated purchased power policies, and PSNH's flexibility resulting from having a variety of fuel sources.

## A. Supply Diversity and Flexibility

As discussed in the previous section, PSNH's supply resource mix includes a variety of fuel sources including coal, oil, hydroelectric, and biomass. In addition, Schiller units 4 and 6 are capable of burning coal or oil and Newington has dual oil and natural gas capability. The diverse supply portfolio allows PSNH to have flexibility in its generation strategy. Exhibit VII-1 demonstrates PSNH's diverse supply resource mix used to meet PSNH's hourly default energy service requirement in 2009.

**Exhibit VII-1: PSNH's 2009 Supply Resource Mix**




PSNH must remain flexible in providing electric service to its default energy service customers. Having physical generation facilities to serve part of PSNH's default energy service load provides flexibility in managing and controlling the costs associated with the ever changing energy market. PSNH's wood-fired boiler for Schiller unit 5 provides PSNH with greater fuel flexibility as well as providing assistance in meeting strict New Hampshire rules on air emissions. With an "open" system, PSNH can readily implement delivery service for retail customers who choose a competitive supplier, yet PSNH is required to be prepared to provide electricity to customers who are not served by a competitive supplier.

## B. Mandated Purchase Policies

PURPA requires PSNH to interconnect with and buy power from generators meeting the FERC's definition of Qualifying Facilities (QFs). Under PURPA, an electric utility must generally purchase any energy and capacity which is made available from a QF (18 CFR 292.303). However, in the Energy Policy Act of 2005, Congress amended PURPA to allow FERC to waive this mandatory purchase requirement if a QF has non-discriminatory access to the competitive market. FERC has granted such a purchase waiver to PSNH regarding QF's with a capacity above 20 MW. As a result, PURPA's mandatory purchase requirement only applies to PSNH for QFs with a capacity of 20 MW or less. Such mandatory purchase of a QF's energy and capacity would be at avoided cost rates established by the State regulatory authority -- in New Hampshire, this Commission.

Virtually all of PSNH's existing long-term purchase obligations from QFs are well above the current market price of energy, creating stranded costs for consumers. A number of QF purchase obligations expired at the end of 2006, which significantly lowered PSNH's stranded cost charge. Per PSNH's Restructuring Settlement Agreement, as existing long-term QF purchase obligations expire, PSNH will agree to purchase, as requested, the output from those QFs at ISO-New England real time market prices, adjusted for administrative cost, wheeling cost and line losses.

# VIII. Integration of Demand-Side and Supply-Side Options

This section analyzes the integration of the supply side options in combination with demand side programs and identifies the combination of options that provide lower costs to customers and are achievable given the constraints of the current environment.

## A. Overview

Under restructuring, PSNH must supply default energy service to those customers who do not choose a competitive energy supplier. Under the current 31 percent migration level, PSNH currently supplies between 80 and 90 percent of customers' energy requirements using its owned and contracted supply sources. PSNH therefore purchases the remaining 10 to 20 percent of its energy requirements from the wholesale market. In the absence of being enabled to build or buy new generation assets to meet customer demand, PSNH procures power on the open market using short-term purchase strategies. If customers were to choose a competitive retail electricity supplier, PSNH has the flexibility to adjust its purchases accordingly to serve default energy service to its remaining customers.

PSNH does not have responsibility for long-term planning of generation. However, as a result of the settlement agreement approved by the Commission in Order No. 24,695 in Docket DE 04-072, PSNH has agreed to provide its views on meeting its customers' future energy and capacity requirements. The responsibility for long-term generation planning lies with the market. Merchant generators will construct new facilities presumably if the price signal is sufficiently high enough to ensure profitability. ISO-New England relies on the market to encourage developers to build new facilities to meet rising customer demand.

Although PSNH does not engage in long-term generation planning for the construction of new units, it is still involved in transmission and distribution planning for the delivery of electricity. Transmission planning is performed by ISO-New England consistent with Northeast Power Coordinating Council (NPCC), North American Electric Reliability Corporation (NERC), and Federal Energy Regulatory Commission (FERC) requirements, but distribution planning is performed by PSNH. PSNH forecasts peak load for 12 areas for the purposes of capital project planning. Once it is determined that a capital improvement project is necessary for a particular area, PSNH begins planning the project. PSNH's C&LM program reduces generation requirements and as economical opportunities present themselves, distributed generation will be utilized to defer capital improvements on the distribution system. However, even with these programs, PSNH is still required to purchase supplemental power from the wholesale market in order to meet default energy service requirements, even under the current 31 percent migration scenario. If the migration situation changes and PSNH is serving more default energy service customers, PSNH could find itself needing more supply to serve default energy service requirements.

## B. Demand Side Options

For purposes of this plan, PSNH performed an assessment of increased energy efficiency and demand-side management programs in accordance with the "Additional Opportunities for Energy Efficiency in New Hampshire" report performed by GDS Associates, the consultant hired by the Commission to investigate the potential for energy efficiency in New Hampshire. PSNH used the GDS study to develop a Market Potential Scenario and fore purposes of this LCIRP, the Market Potential Scenario was used as the high end for energy efficiency levels and the current level of energy efficiency, funded at 1.8 mills per kWh before money was diverted to the Low Income Home Energy Assistance Program, was used as the base case level of energy efficiency.

## C. Supply Side Options

PSNH analyzed small scale distributed generation options that it feels could provide long-term rate stability to customers, fuel diversity, Renewable Portfolio Standard compliance, environmental and economic benefits, and enhance the reliability of New England's electricity supply.

PSNH selected two 1 MW ground-mounted solar photovoltaic installations as reasonably representative projects that could be installed in accordance with RSA 374-G to help PSNH meet a portion of the New Hampshire RPS requirement and provide PSNH with an intermittent source of energy and capacity. At this time, PSNH does not want to overburden customers with the overmarket cost of utility-scale solar PV installations and is seeking opportunities to obtain supplemental funding subsidies to defray the overmarket cost to customers. PSNH believes that two installations of up to 2 MW could be installed over the planning horizon. Solar photovoltaics may be an economic solution in the long-term and will help to satisfy PSNH's Class II New Hampshire RPS requirement, diversify its supply sources further, and provide a benefit to customers. PSNH will continue to seek opportunities to invest in economic solar PV installations, supplemented by increased state or federal funding.

## D. Integrated Portfolio Approach

As described above, PSNH identified potential increased energy efficiency and demand-side management programs and an additional small scale distributed generation supply-side option that could be used to reduce the energy and renewable requirement gap to the extent the energy efficiency measures are undertaken by default energy service customers and the distributed generation is assigned to meet default energy service requirements. The capacity gap is unaffected because the wholesale market revenues from energy efficiency and demand-side management programs and the distributed generation solar PV project benefit the CORE Programs and PSNH's distribution customers, respectively, not default energy service customers. Although PSNH's default energy service peak load is likely to be impacted by these programs, the effect is second-order and is unlikely to have a measurable impact on PSNH's default energy service capacity obligation.

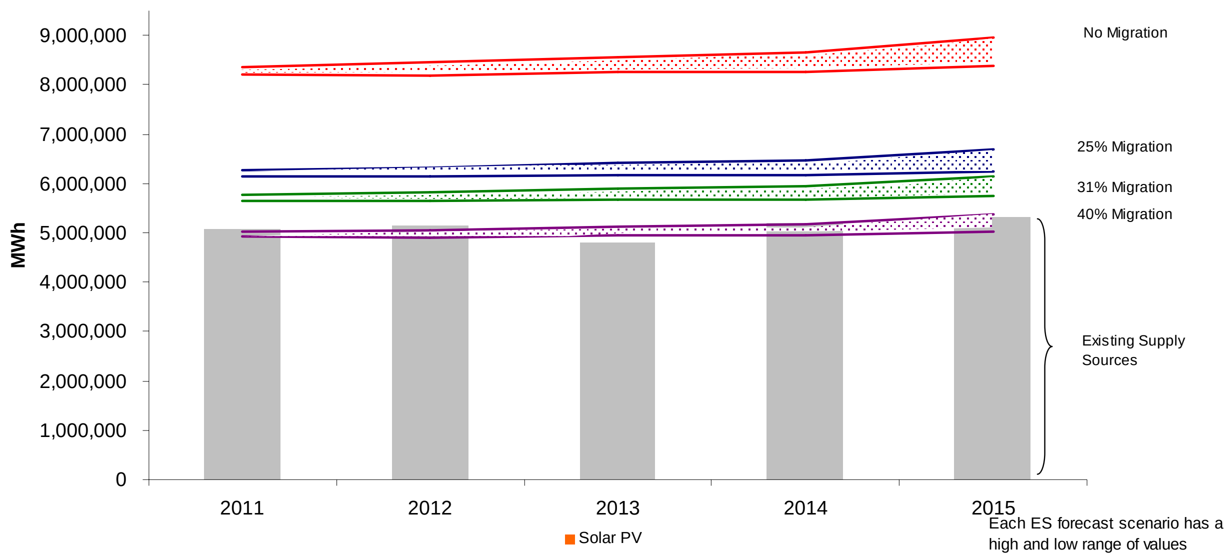
The chart and table in Exhibit VIII-1 shows the potential ranges of energy requirement need under a range of forecasted energy requirement levels. PSNH developed a range of forecasted energy requirement levels based on varying economic and price assumptions, migration levels, and energy efficiency levels. The highest and lowest combinations were selected to provide the bandwidth of potential surrounding each migration level.

The high scenario is the high delivery sales forecast (good economic conditions and low electric prices) with the specified level of customer migration to competitive energy suppliers combined with the Market Potential Scenario for energy efficiency.

The low scenario is the low delivery sales forecast (poor economic conditions and high electric prices) with the specified level of customer migration to competitive energy suppliers and the current level of energy efficiency funding.

Since the additional supply side resources proposed are small, there is little impact to the energy requirement gap. The major driver of the energy supply gap will be the level of migration that is experienced over the planning period.

## Exhibit VIII-2: Energy Resource Portfolio




| | GWh | | | | |
|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 |
| Existing Supply-Side Resources | 5,063 | 5,143 | 4,792 | 5,192 | 5,312 |
| New Supply-Side Resources | 1 | 1 | 1 | 2 | 2 |
| | | | | | |
| **Migration Level: 40%** | | | | | |
| Total ES Requirement – High scenario | 5,012 | 5,059 | 5,125 | 5,178 | 5,367 |
| Supplemental ES Purchases – High scenario | (50) | (4) | 62 | 115 | 305 |
| Total ES Requirement – Low scenario | 4,917 | 4,905 | 4,937 | 4,938 | 5,024 |
| Supplemental ES Purchases – Low scenario | (146) | (158) | (125) | (125) | (38) |
| | | | | | |
| **Migration Level: 31%** | | | | | |
| Total ES Requirement – High scenario | 5,764 | 5,817 | 5,891 | 5,945 | 6,153 |
| Supplemental ES Purchases – High scenario | 702 | 755 | 828 | 883 | 1,090 |
| Total ES Requirement – Low scenario | 5,655 | 5,640 | 5,671 | 5,660 | 5,741 |
| Supplemental ES Purchases – Low scenario | 592 | 577 | 609 | 597 | 678 |

| | GWh | | | | |
|---|---|---|---|---|---|
| | **2011** | **2012** | **2013** | **2014** | **2015** |
| | | | | | |
| **Migration Level: 25%** | | | | | |
| Total ES Requirement – High scenario | 6,266 | 6,326 | 6,408 | 6,469 | 6,696 |
| Supplemental ES Purchases – High scenario | 1,204 | 1,264 | 1,345 | 1,407 | 1,634 |
| Total ES Requirement – Low scenario | 6,147 | 6,133 | 6,171 | 6,161 | 6,252 |
| Supplemental ES Purchases – Low scenario | 1,084 | 1,071 | 1,108 | 1,099 | 1,189 |
| | | | | | |
| **Migration Level: 0%** | | | | | |
| Total ES Requirement – High scenario | 8,357 | 8,446 | 8,564 | 8,652 | 8,960 |
| Supplemental ES Purchases – High scenario | 3,295 | 3,384 | 3,501 | 3,589 | 3,898 |
| Total ES Requirement – Low scenario | 8,199 | 8,190 | 8,251 | 8,250 | 8,382 |
| Supplemental ES Purchases – Low scenario | 3,136 | 3,128 | 3,188 | 3,187 | 3,320 |

# IX. Assessment of Plan Integration and Impact on State Compliance with the Clean Air Act Amendments of 1990

This section assesses PSNH's compliance with the Clean Air Act Amendments of 1990 and describes the strategies PSNH employs to reduce emissions in accordance with federal and state regulations and regional policies.

## A. Overview

PSNH has implemented an integrated approach to emissions management and fuel supply planning. An integrated approach is necessary due to the interdependent nature of the two activities.

Federal and state environmental regulations essentially determine what fuels may be burned by PSNH's fossil-fuel fired generation fleet – Merrimack, Schiller and Newington Stations. In order to comply with increasingly more stringent regulations, PSNH has been very proactive and progressive in reducing and managing emissions. The flexibility provided under market-based incentive programs, including the New Hampshire Clean Power Act (RSA Chapter 125-O), allows PSNH to implement the most cost-effective measures to meet its emission reduction requirements.

Close management of PSNH's emissions allocations and allowance transactions, fuel switching and capital additions, while maintaining a diverse fuel mix, enables PSNH to operate the fleet in the most cost effective manner. Recognizing the upward pressure on electricity costs caused by more stringent regulation and higher compliance costs, this approach is critical and provides the most benefit to PSNH's customers and shareholders.

## B. Emissions Policies at the Federal Level

Under existing state and federal regulations, several pollutants emitted by PSNH's electric generating stations are currently regulated, monitored and controlled.

The federal Clean Air Act Amendments of 1990 (CAAA) established challenging goals for the electric power industry. Compliance with lower $SO_2$ emission levels, to be met in a two-phase stepped approach under a national cap and trade program, was mandated under Title IV. NOx emission reductions requirements were imposed under Title IV and Title I, while Title III required a study of hazardous air pollutants, including mercury, from electric utilities. The CAAA also contained the framework for the future control of particulate emissions through, for example, programs to meet national ambient air quality standards and visibility improvements.

The visibility rule, or regional haze rule, requires States to develop long-term strategies to address their contribution to visibility both within and outside the State. In developing their long term strategy for regional haze, States can take into account emission reductions due to ongoing air pollution control programs. One of the principal elements of the visibility rule is the installation of best available retrofit technology (BART) for certain existing sources placed into operation between 1962 and 1977. In determining BART, the State can take into account several factors, including the existing control technology in place at the source, the costs of compliance, energy and nonair environmental impacts of compliance, remaining useful life of the source, and the degree of visibility improvement that is reasonably anticipated from the use of such technology. BART for Merrimack Unit 2 and Newington Unit 1 has been determined by the New Hampshire Department of Environmental Services (NHDES) to be use of existing control equipment and lower sulfur fuels.

States were required to submit complete control strategy plans for regional haze no later than 2008. Subsequent revisions to the State implementation plans are required in 2018, and every 10 years thereafter. With each revision, the State is required to set new progress goals and strategies to meet the goals.

Title IV of the CAAA set a goal of reducing annual $SO_2$ emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants.

Phase I began in 1995 and affected 263 units at 110 of the mostly coal-burning electric utility plants located in 21 eastern and Midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Emissions data indicate that 1995 $SO_2$ emissions at these units nationwide were reduced by almost 40 percent below their required level.

Phase II, which began in 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing over 2,000 units in all.

Title IV also called for a two-part strategy to reduce NOx emissions from coal-fired electric power plants by 2 million tons by the year 2000, by over 400,000 tons per year between 1996 and 1999 and by approximately 1.17 million tons per year beginning in the year 2000.

In addition to the Title IV requirements, NOx emissions reduction requirements were also mandated under Title I of the Act. Beginning in 1995 with the implementation of NOx Reasonably Available Control Technology (RACT) Programs, NOx emission standards were imposed requiring the installation of emissions control technology at generating stations throughout the Northeast. Beginning in 1999, ozone season NOx emissions were regulated through the implementation of NOx Budget Programs in twelve states throughout the Northeast, including New Hampshire. By 2004, through the implementation of the NOx State Implementation Plan (SIP) Call, NOx Budget Programs were required in 20 states throughout the eastern and Midwestern United States (excluding New Hampshire, Maine and Vermont).

Under Title III of the CAAA, 189 hazardous air pollutants (HAPs), including mercury (Hg), are regulated. Title III requirements include reductions of HAPs through the implementation of a Maximum Achievable Control Technology (MACT) standard. MACT is a control technology driven emission standard based on the maximum control achievable in a particular industry.

On March 15, 2005, the Environmental Protection Agency (EPA) published a rule that modified its so-called “Regulatory Determination” that regulation of HAP emissions from

Electric Utility Steam Generating Units (EUSGU) was "appropriate and necessary." On the same day, EPA finalized the "Clean Air Mercury Rule" (CAMR) that controls mercury emissions through a cap and trade program. The states have the option to participate in the cap and trade program. Each participant state may allocate its allowance budget to the affected facilities within the state, as it sees fit. For non-participant states, the allowance budget becomes a fixed, enforceable emission limit for the state. The states may adopt more stringent controls on EUSGUs or regulate other source categories if they wish.

The implementation of the EUSGU MACT has been delayed as a result of litigation. On February 8, 2008, the United States Court of Appeals for the D.C. Circuit vacated CAMR by ruling that the regulation of mercury emissions from existing coal fired EUSGUs under Section 111 of the Clean Air Act is prohibited, effectively invalidating EPA's regulatory approach, because coal-fired EUSGUs are listed sources under Section 112.

On December 18, 2008, Plaintiffs in *American Nurses Association, et al. v. Jackson*, filed a complaint in the United States District Court for the District of Columbia alleging that EPA failed to perform a non-discretionary duty to promulgate final maximum achievable control technology emissions standards for hazardous air pollutants from coal- and oil-fired electric utility steam generating units pursuant to Section 112(d) of the Clean Air Act by the statutorily-mandated deadline. As a result, EPA entered into a consent decree with the Plaintiffs which requires the publication of proposed emission standards pursuant to Section 112(d) no later than March 16, 2011 and a notice of final rulemaking setting forth EPA's final emissions standards for coal- and oil-fired EUSGUs no later than November 16, 2011. In preparation of this rulemaking, EPA approved an Information Collection Request (ICR) On December 24, 2009, requiring all U.S. power plants with coal-or oil-fired electric generating units to submit emissions information for use in developing air toxics emissions standards.

In addition to future regulations being implemented under the CAAA, several bills regulating emissions, including greenhouse gases, from fossil-fuel fired electric utility generators have been introduced in Congress.

## C. State and Regional Activities

Prior to the passage of the CAAA, the State of New Hampshire implemented the Acid Rain Control Act (RSA Chapter 125-D) imposing an annual $SO_2$ cap of 55,150 tons from the combined output of PSNH's large electric generators. Although PSNH measures and monitors $SO_2$ emissions from individual units, $SO_2$ emissions are managed and controlled on a system-wide basis by utilizing a spectrum of fuel types and qualities.

In addition to the CAAA requirements, the State of New Hampshire enacted the New Hampshire Clean Power Act (RSA Chapter 125-O) in 2002 establishing a market-based economic incentive program regulating emissions of $SO_2$, NOx, mercury, and $CO_2$, beginning in January 2007. This program is in addition to the existing state and federal $SO_2$ and NOx emissions programs. In 2006, legislation updating RSA Chapter 125-O specific to mercury emissions reduction requirements was passed. As a result, PSNH is required to install a wet flue gas desulphurization system ("scrubber") at Merrimack

Station and reduce overall mercury emissions by 80 percent by July 1, 2013. The Commission is monitoring PSNH's compliance with this mandate in Docket No. DE 08-103.

Simply stated, the New Hampshire Clean Power Act establishes an output-based allocation program which allows PSNH to either implement on-site emissions reductions and/or purchase allowances to comply. As stated in RSA Chapter 125-O:1, VI, "…the environmental benefits of air pollutant reductions can be most cost-effectively achieved if implemented in a fashion that allows for regulatory and compliance flexibility under a strictly limited overall emissions cap. Specifically, market-based approaches, such as trading and banking of emission reductions within a cap-and-trade system, allow sources to choose the most cost-effective ways to comply with established emission reduction requirements. This approach also provides sources with an incentive to reduce air pollutant emissions sooner and by greater amounts, promotes the development and use of innovative new emission control technologies, and specifies to the greatest extent possible performance results regarding environmental improvement rather than dictating expensive, facility-specific, command-and-control regulatory requirements."

The requirements enacted under RSA Chapter 125-O, and the implementing administrative rules, Env-A 2900 apply to PSNH's existing fossil fuel burning steam electric power plant units, namely Merrimack Units 1 and 2, Schiller Units 4, 5, and 6, and Newington Unit 1, excluding any units that are repowered. Pursuant to RSA Chapter 125-O:3 and Env-A 2905, PSNH will receive annual allocations, based on the output of each unit, of 7,289 tons of $SO_2$, 3,644 tons of NOx, and 5,425,866 tons of $CO_2$. The annual emission cap for mercury will be determined by NHDES following review and approval of PSNH's mercury baseline coal testing and baseline emissions testing undertaken during 2006 and 2007.

Under RSA Chapter 125-O and Env-A 2900, PSNH is required to reduce emissions to comply with the annual emissions budgets implemented and/or purchase allowances to offset any emissions in excess of the annual allocations. PSNH's compliance plan, filed with the New Hampshire Department of Environmental Services in July 2003, describes the technologies, operational modifications, market-based approaches, or other methods that will be used to comply with the emission budgets in the most cost effective manner.

Since January 1, 2007, PSNH has been reducing emissions on-site and purchasing allowances in order to comply with the annual emissions budgets implemented under the New Hampshire Clean Power Act.

## D. PSNH's Initiatives and Emissions Policy Conclusions

PSNH will continue to comply with the regulations outlined above through proactive, cost effective mechanisms including fuel switching, emissions allowance management (sale, procurement, and/or use), emission rate optimization, close monitoring, and measurement of emissions. Emission allowance management comprises the assessment of PSNH-specific requirements versus state and federal allocations and allowance inventory levels. Generally, $SO_2$ and NOx emission allowances are market-traded fungible commodities that are available for purchase and sale (in a transparent market) as market participants balance their respective supply and demand requirements over a period of time. Annual system requirements are estimated on a pro forma basis using anticipated generating unit capacity factors, emission rates, and potential fuel type availability and pricing information. Balancing fuel qualities, emission allowances, and capacity factors to meet the regulatory requirements is the crux of this overall effort.

A subgroup of PSNH's Generation management team meets at least annually to comprehensively analyze PSNH's position and to set strategic direction for PSNH Generation. Also during an additional eight to ten meetings throughout the year, an emissions management team formally discusses the system's emissions status, makes pro forma assessments (with sensitivity analyses) and makes tactical decisions to achieve its goal of complying with the emission regulations in a cost-effective manner. Various short-term methods employed to change emission levels include switching to higher or lower sulfur fuels; either high sulfur coal to low sulfur coal or high sulfur residual oil (up to 2 percent sulfur) to lower sulfur oil and/or natural gas consumption. This group analyzes year-to-date data and implements the necessary changes in order to comply on a real-time basis.

# X. Compliance with the New Hampshire Renewable Portfolio Standard

This section assesses PSNH's compliance with the New Hampshire Electric Renewable Portfolio Standard (RPS) and describes the strategies PSNH employs to comply with the RPS.

## A. Background

New Hampshire's RPS requires electricity providers to acquire RECs equivalent to 23.8 percent of retail electricity sold to end-use customers by 2025. Of the 23.8 percent target, 16.3 percent is to be derived from sources installed after January 1, 2006, whereas the remainder may be derived from existing resources. 2007 N.H. Laws, Chapter 25 (2007 H.B. 873) created a new RSA Chapter 362-F titled "*ELECTRIC RENEWABLE PORTFOLIO STANDARD*."

RSA 362-F:1 describes the purpose of the Renewable Portfolio Standard as follows:

> "Renewable energy generation technologies can provide fuel diversity to the state and New England generation supply through use of local renewable fuels and resources that serve to displace and thereby lower regional dependence on fossil fuels. This has the potential to lower and stabilize future energy costs by reducing exposure to rising and volatile fossil fuel prices. The use of renewable energy technologies and fuels can also help to keep energy and investment dollars in the state to benefit our own economy. In addition, employing low emission forms of such technologies can reduce the amount of greenhouse gases, nitrogen oxides, and particulate matter emissions transported into New Hampshire and also generated in the state, thereby improving air quality and public health, and mitigating against the risks of climate change. It is therefore in the public interest to stimulate investment in low emission renewable energy generation technologies in New England and, in particular, New Hampshire, whether at new or existing facilities."

The RPS separates the portfolio standards required for energy resources into four classes: "Class I," "Class II," "Class III," or "Class IV." The definitions of each of the four classes are described below.

- Class I - New Renewable Energy: electricity from any of the following, provided the source began operation after January 1, 2006:
    - Wind energy
    - Geothermal energy
    - Hydrogen derived from biomass fuels, biogas, or landfill gas
    - Ocean thermal, wave, current, or tidal energy
    - Biogas or landfill gas
    - Eligible biomass technologies meeting air emissions requirements
    - Solar electric not used to meet Class II, or customer-sited solar water heating that displaces electricity
    - The incremental new production of electricity in any year from an eligible biomass, eligible methane source, or hydroelectric generating facility of any capacity, over its historical generation baseline
    - The production of electricity from Class III or IV sources that have been upgraded or repowered through significant capital investment.
- Class II - New Solar: electricity from solar technologies provided the source began operation after January 1, 2006.
- Class III - Existing Biomass/Methane: electricity from eligible biomass technologies having a gross nameplate capacity of 25 MW or less, and methane gas. The source must have begun operation prior to January 1, 2006:
- Class IV - Existing Small Hydroelectric: electricity from hydroelectric energy provided the source began operation prior to January 1, 2006, has a gross nameplate capacity of 5 MW or less, and meets other environmental protection criteria.

Every provider of electric energy must meet the standard according to the following compliance schedule. Exhibit X-1 shows PSNH's compliance obligation over the planning horizon by class on a percentage basis and a total megawatt hour basis under a high and low scenario. The high load case assumes the reference delivery energy sales forecast with current energy efficiency levels and no customer migration assumptions. The low load case assumes the reference delivery energy sales forecast with current energy efficiency levels and 40 percent customer migration assumptions. The forecasted load will be somewhere in between this bandwidth.

**Exhibit X-1: RPS Compliance**

| (%) | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| Class I | 2.00% | 3.00% | 4.00% | 5.00% | 6.00% |
| Class II | 0.08% | 0.15% | 0.20% | 0.30% | 0.30% |
| Class III | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| Class IV | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% |

| (MWh) | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| Class I – High Case | 165,447 | 251,039 | 335,966 | 425,179 | 515,304 |
| Class I – Low Case | 99,228 | 150,355 | 201,043 | 254,422 | 308,656 |
| Class II – High Case | 6,618 | 12,552 | 16,798 | 25,511 | 25,765 |
| Class II – Low Case | 3,969 | 7,518 | 10,052 | 15,265 | 15,433 |
| Class III – High Case | 537,703 | 543,918 | 545,945 | 552,733 | 558,246 |
| Class III – Low Case | 322,491 | 325,768 | 326,694 | 330,748 | 334,378 |
| Class IV – High Case | 82,723 | 83,680 | 83,992 | 85,036 | 85,884 |
| Class IV – Low Case | 49,614 | 50,118 | 50,261 | 50,884 | 51,443 |

## B. Rules for Compliance

In order to comply with the New Hampshire RPS, the NHPUC established a REC program utilizing the regional generation information system (GIS) of energy certificates administered by ISO-New England and the New England Power Pool (NEPOOL). RECs from customer-sited sources are assigned to the system owner and behind-the-meter generation located in New Hampshire is eligible to participate in the New Hampshire RPS. Unused RECs from the prior two years, or RECs from the first quarter of a subsequent year, can be used to meet up to 30 percent of a given year's compliance targets.
To be eligible for New Hampshire RPS compliance, renewable energy sources must be located within the New England control area unless the source is located in a control area adjacent to the New England control area and the energy produced by the source is actually delivered into the New England control area for consumption by New England customers.

Compliance reports are filed with the Commission by July 1st of each year from each electricity provider. In lieu of meeting the portfolio requirements, an electricity provider may make payments to the renewable energy fund established by this law to support renewable energy initiatives. Class II moneys will only be used to support solar energy technologies in New Hampshire.

Default service providers are authorized to recover prudently incurred compliance costs of the New Hampshire RPS from retail customers. The NHPUC is authorized to fine competitive electricity suppliers that violate New Hampshire RPS requirements, revoke their registration, or prevent them from doing business in the state.

If the New Hampshire RPS requirement can not be met through ownership of qualified renewable generation sources or the purchase of RECs from a qualified renewable generation source, the provider has the option to pay the Alternative Compliance Payments (ACP) to the State of New Hampshire. The 2010 ACP rates for each MWh not met for a given class obligation through the acquisition of certificates are $60.93 for Class I, $160.01 for Class II, and $29.87 for Classes III and IV. The Commission adjusts these rates by January 31st of each year using the Consumer Price Index (CPI).

The Commission may accelerate or delay by up to one year, any given year’s increase in class I or II New Hampshire RPS requirement for good cause, and after notice and hearing. In addition, after notice and hearing, the Commission may modify the Class III and IV requirements for calendar years beginning January 1, 2012 such that the requirements are equal to an amount between 85 percent and 95 percent of the reasonably expected potential annual output of available eligible sources after taking into account demand from similar programs in other states.

The Commission must conduct a review of the New Hampshire RPS program and report its findings to the legislature by November 1, 2011, 2018, and 2025, including any recommendations for changes to the class requirements or other aspects of the electric renewable portfolio standard program. In addition, the Office of Energy and Planning in consultation with the Energy Planning Advisory Board is directed to study, evaluate, and make recommendations including potential legislation related to a thermal renewable portfolio standard and other incentives or mechanisms to promote thermal renewable energy use.[15]

## C. PSNH's Renewable Strategy

PSNH is focused on long-term renewable resources. Currently, the renewable power included in PSNH's resource supply mix includes hydroelectric, wood, solar and wind resources. PSNH was able to successfully expand its portfolio by constructing a wood-fired boiler at Schiller Station, refurbishing the Smith Hydro plant, and adding solar photovoltaic panels to its Energy Park headquarters building. PSNH also entered into a long-term Power Purchase Agreement with Lempster Wind for a portion of its output and environmental attributes. PSNH recently signed a Power Purchase Agreement with Laidlaw Berlin BioPower, LLC for energy, capacity, and renewable attributes associated with the proposed 60 MW biomass plant in Berlin, New Hampshire. The Laidlaw Power Purchase Agreement requires approval by the Commission, and the Laidlaw plant is expected to be in service by mid-2013.

With a large number of PURPA rate orders expiring in the next couple of years, a vibrant REC market developing in New England, federal and state incentives for developers of renewable projects, and a state law allowing PSNH to invest in small scale distributed renewable energy resources, PSNH sees renewable power as a viable strategy to help keep energy prices stable over the long-term.

PSNH will continue to be active in the regulatory process associated with implementation of the New Hampshire RPS standard and the disbursement of Renewable Energy Funds to determine the means by which lowest cost compliance can be achieved.

For Class I, Northern Wood Power is qualified as a REC-eligible asset in New Hampshire. PSNH has historically sold the RECs from NWP to other New England states due to an early valuation of the RECs in the other New England states and to assure appropriate crediting of value in satisfaction of the NWP settlement agreement terms. In addition, the incremental output of the Smith Hydro refurbishment and the Lempster Wind Power Purchase Agreement also qualify for Class I RECs. The Laidlaw Power Purchase Agreement will also qualify for Class I RECs.

For Class II, PSNH's solar photovoltaic installation at Energy Park has been qualified by the Commission as a Class II eligible facility and the output from that facility can be used to meet PSNH's Class II requirements. In addition, PSNH is looking into developing its own solar photovoltaic program under RSA 374-G which allows utilities to invest in distributed generation up to 5 MW per site. The federal Investment Tax Credit coupled with the State of New Hampshire Office of Sustainability's residential rebate program for customers' investments in solar photovoltaic may entice more residential customers to install solar photovoltaic. However, due to size and program design, these installations do not typically provide RECs in the market for RPS compliance. Absent increased state or

---

[15] Database of State Incentives for Renewables and Efficiency (DSIRE) - http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NH09R&state=NH&CurrentPageID=1&RE=1&EE=1

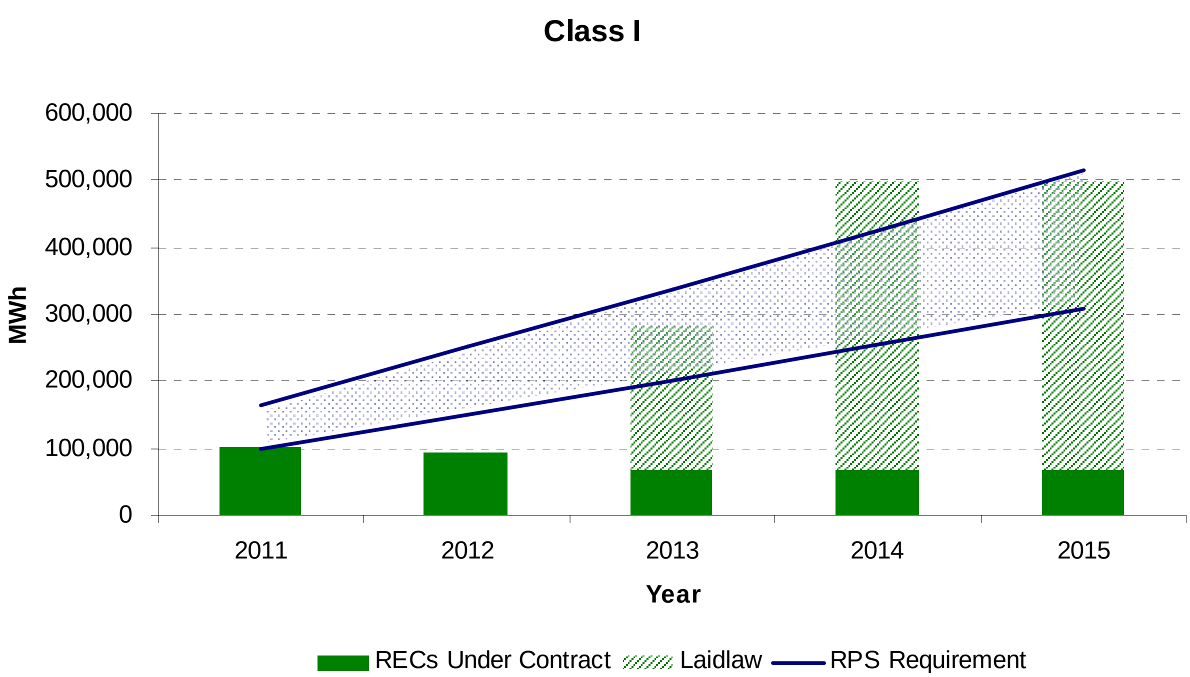
federal grants and funding for REC-producing solar projects, it is likely that compliance with Class II RPS requirements will include Alternative Compliance Payments.

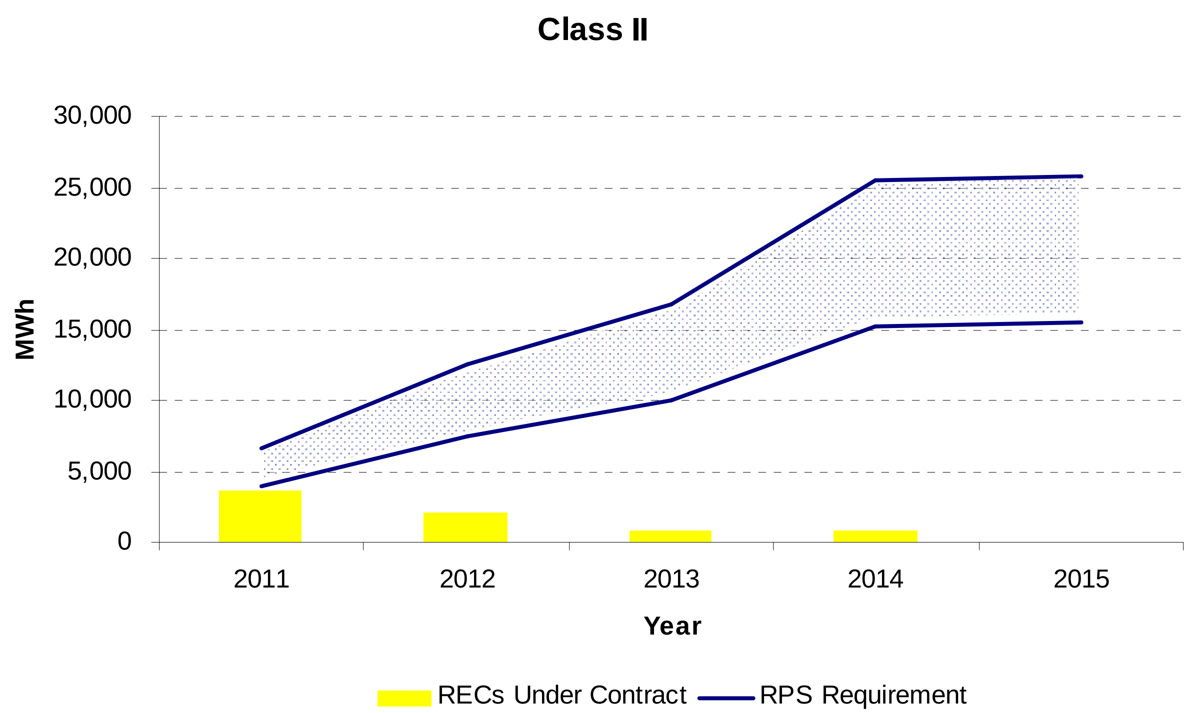
For Class III, PSNH will seek to establish intermediate term contracts (1 to 3 years) with facilities that qualify to provide Class III RECs. It should be noted that PSNH believes that many of these facilities, and in particular the existing biomass facilities, if qualified to provide Class III RECs in New Hampshire, will also have the opportunity to provide Class 1 RECs in Connecticut. The market price differential between Class 1 Connecticut RECs and Class III New Hampshire RECs and other factors will dictate the availability of Class III RECs for purchase by PSNH to meets its Class III New Hampshire RPS obligation, leading to possible compliance that includes Alternative Compliance Payments.

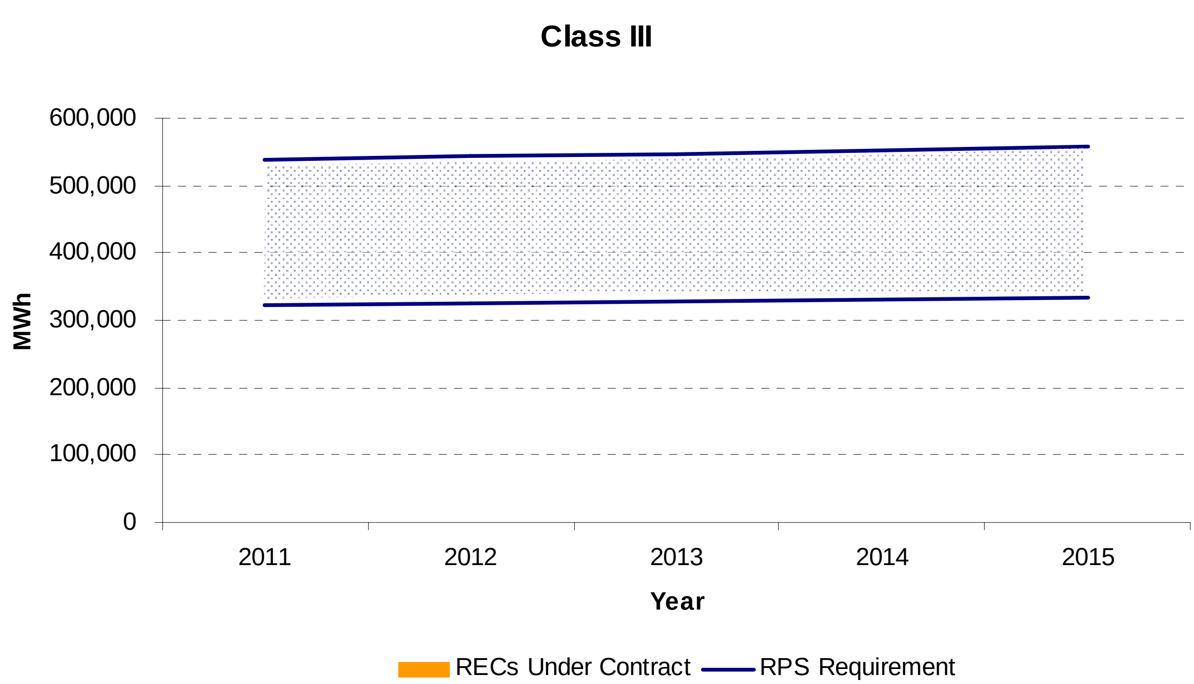
For Class IV, PSNH used some of its existing hydroelectric facilities in 2009, but after 2009, these facilities no longer qualify as REC-eligible under New Hampshire RPS rules. PSNH will continue to seek contracts with New Hampshire REC-eligible facilities or pay the Alternative Compliance Payment to fulfill its Class IV obligation.

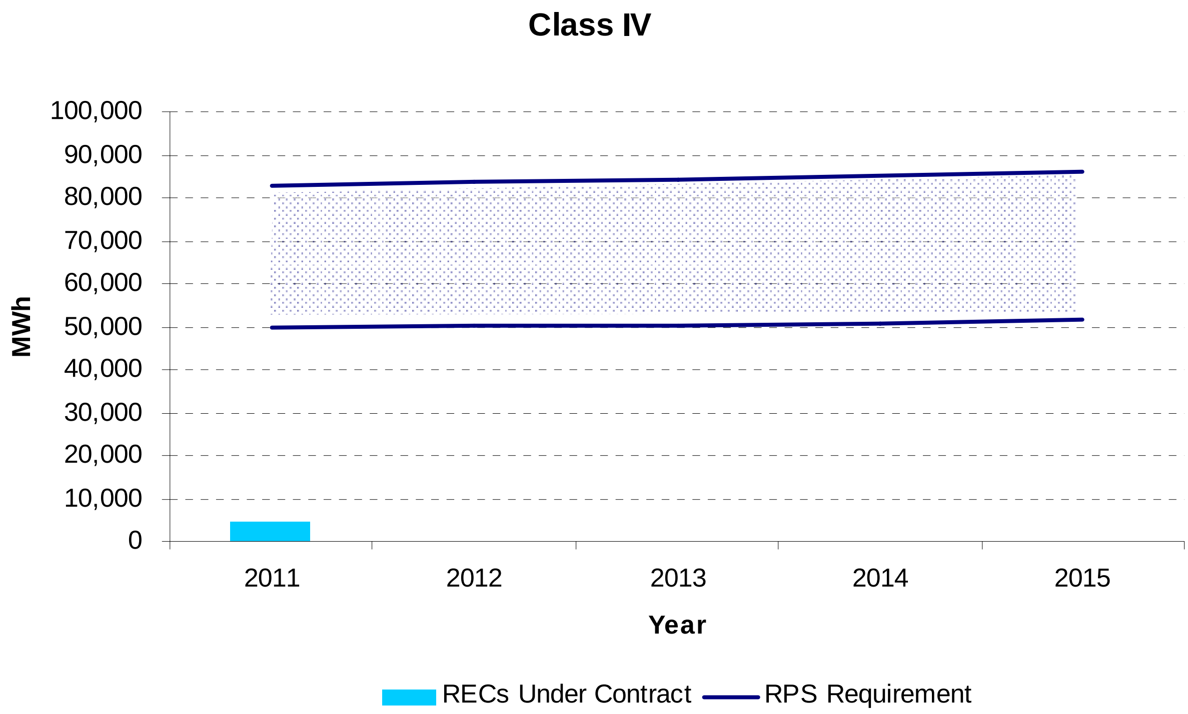
Exhibit X-3 demonstrates PSNH's current RPS compliance gap for each of the renewable classes under a high and low load forecast and migration scenario.

**Exhibit X-3: PSNH's Current RPS Compliance Gap by Class**




Class II
30,000
25,000
20,000
15,000
10,000
5,000
0
MWh
2011
2012
2013
2014
2015
Year
RECs Under Contract
RPS Requirement


Class III
600,000
500,000
400,000
300,000
200,000
100,000
0
MWh
2011
2012
2013
2014
2015
Year
RECs Under Contract
RPS Requirement




With respect to RPS Classes II, III, and IV, New Hampshire's renewable resource goals could be enhanced by reviewing the State's RPS law to increase the feasibility of compliance through opportunities to increase renewable resources in New Hampshire for these classes in lieu of making Alternative Compliance Payments.

# XI. Compliance with the National Energy Policy Act of 1992

RSA 378:38, VIII requires that the Company's Least Cost Plan include a discussion of compliance with the National Energy Policy Act of 1992. (EPAct) This section describes PSNH's compliance with the sections of the EPAct.

## A. Energy Policy Act of 1992

The Public Utility Regulatory Policies Act of 1978 required state public utilities commissions to consider certain standards for ratemaking including cost of service, declining block rates, interruptible and time of day rates. (16 USC §2621(d)) Although the state commissions were required to consider the federal standards outlines in this PURPA, they were not bound to implement them. (16 USC §2621(c)) The Energy Policy Act of 1992 added additional standards to PURPA for state consideration which relate directly to integrated resource planning. "Energy Policy Act of 1992, Subtitle B – Utilities – Amends the Public Utilities Regulatory Policies Act of 1978 (PURPA) (1) to mandate that: each electric utility employ integrated resource planning; (2) the rates for a State regulated electric utility are such that its outlay for demand side management measures (including energy conservation and energy efficiency resources), are at least as profitable as those for the construction of new generation, transmission, and distribution equipment; (3) the rates charged by an electric utility are such that it is encouraged to make outlays for all cost-effective improvements in energy efficient power generation, transmission and distribution; and (4) such rates and charges are implemented in a manner that assures that utilities are not granted unfair competitive advantages over small businesses engaged in the transactions regarding demand side energy management measures." Public Law No. 102-486, Summary as of 10/5/1992 Conference Report filed in the House.

As with other PURPA standards, Congress required each state regulatory authority to determine whether or not it is appropriate to implement such standard. The Commission initiated its Docket No. DE 06-061 to comply with this mandate. The following sections describe each new standard in more detail.

It should also be noted that in the Energy Policy Act of 2005, Congress added several additional standards to PURPA for state regulatory authority consideration. These newer standards relate to net metering, fuel sources, and fossil fuel generation efficiency. The Commission opened Docket No. DE 06-061 to consider these newest PURPA standards.

### A.1. Requirement to Perform Integrated Resource Planning

The EPAct included a new standard suggesting that integrated resource plans must be updated on a regular basis, provide for public participation, and the plans must be implemented. 16 USC 2621(d)(7). RSA 378:38 requires electric utilities to file a least cost integrated resource plan biennially, unless the Commission waives the requirement. The Commission typically opens an adjudicatory proceeding with the opportunity for intervention and full participation by interested members of the public. There is extensive discovery and there is an opportunity for testimony to be filed. RSA 378:40 requires that a plan be on file before any rate change can take place. RSA 378:41 requires that in any proceeding initiated by a utility include in the hearing and the decision conformity with the least cost integrated resource plan most recently filed and approved by the Commission.

### A.2. Rates for Demand Side Investment Commensurate with those for Generation, Transmission and Distribution

Under the EPAct, "The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment." 16 USC 2621(d)(8)

Prior to restructuring, when PSNH recovered the costs of conservation and load management expenditures through base rates, it was allowed to recover lost fixed costs revenues. This recovery method attempted to compensate PSNH for installing energy efficiency measures which reduced the sales and corresponding revenues PSNH would have recovered had the energy efficiency measures not been installed. This recovery mechanism lost favor as the amount of lost fixed cost revenues became quite large as a percentage of the total program expenditures in between general rate cases. The Energy Efficiency Working Group developed the Shareholder Incentive, which is in place today, as an alternative to lost fixed cost revenues.

Under the CORE Programs, PSNH and other utilities are allowed to earn a performance incentive based upon meeting a cost effectiveness test and meeting or exceeding a pre-determined level of lifetime kilowatt-hour savings. If the utilities meet this two pronged test, they can recover from 8 to 12 percent of the program budgeted expenditures. PSNH has earned an incentive in previous years.

PSNH recovers its capital investment in generation, transmission and distribution through rates by collecting a depreciation rate for its investment (a return of the investment) and a rate of return on the undepreciated portion of the investment (a return on the investment). The current design of the CORE Programs, including a recovery of the Shareholder Incentive, does not track the loss of return PSNH experiences when it displaces sales in a manner equal to the method using lost fixed cost revenues. Lost fixed cost recovery had become too unwieldy in the period before the CORE Programs were introduced. The Shareholder Incentive provides some financial relief to PSNH but does not provide full compensation for lost fixed cost recovery or a traditional rate base/rate of return regulation for supply side investments. The Shareholder Incentive applies for only one year; however, the lost sales continue year after year for the life of the products and measures installed.

In the least cost integrated resource plan filed in 2007, PSNH anticipated that these issues would be taken up generically in the Energy Efficiency Rate Mechanism proceeding, Docket No. DE 07-064. In Order No. 24,934 in that proceeding (January 16, 2009), the Commission concluded that the formula adopted for electric utilities appeared to be working and that decoupling issues would be addressed in subsequent rate design proposed in individual utility rate proceedings. In the context of the CORE Programs monthly meetings (Docket No. DE 09-170), a subgroup of the Parties is revisiting the Shareholder Incentive.

### A.3. Rates to Encourage Cost-Effective Investments in More Efficient Power Generation, Transmission and Distribution

PSNH is allowed to recover its prudently incurred costs of generation from customers who take default energy service. Any shortfall or excess in the recovery of energy costs is reconciled through subsequent default energy service revenues. Transmission costs are collected through a Transmission Cost Adjustment Mechanism (TCAM). As fully reconciled tracking mechanisms, default energy service and TCAM provide timely recovery of cost effective investments in generation. For major modifications to its generating plants, PSNH must generally first obtain a public interest determination by the Commission and approval of a cost recovery mechanism. (RSA 369-B:3-a) The Commission's current practice includes a requirement that PSNH comply with the new Energy Policy Act of 2005 Fossil Fuel Generation Efficiency Standard -- See Order No 24,893 (September 15, 2008) in Docket No. DE 06-061, Investigation into Standards in Energy Policy Act of 2005. RSA 125-O:5 allows PSNH to use unencumbered energy efficiency funds to make efficiency improvements at its facilities and the Department of Environmental Services can offer additional emission allowances for such efficiency improvements that reduce emissions.

Distribution rates are set on a traditional historic rate base/rate of return basis. There are no specific incentives in those rates which encourage improvements in efficiency of the delivery function. In the most recent rate case settlement filed with the Commission in Docket DE 09-035, there are a portion of increases provided which will improve the timeliness and recoverability of distribution system investments. Also, certain revenues are specifically set aside for reliability enhancements in operation and maintenance expense and in capital investments.

For the Transmission component of PSNH's business, FERC has endorsed pricing policies and financial incentives to ensure the construction of necessary transmission infrastructure, including higher rates of return on equity for transmission investment.

### A.4. Avoidance of Unfair Competitive Advantages over Small Businesses Engaged in Demand Side Energy Management Measures

PSNH's costs for demand side management programs are generally recovered through a portion of the revenues generated by the System Benefits Charge. PSNH operates the CORE Programs with funding from the System Benefits Charge; however, the energy measures and services are delivered through contracts with local businesses. Energy efficient lighting products are sold through a catalogue. The catalogue promotes new lighting fixtures which accept compact fluorescent lamps. The goal of the lighting catalogue program is to transform the market of home lighting by introducing fixtures and lamps that use more efficient compact fluorescent lamps. In addition to the catalogue, PSNH partners with ninety-one lighting retailers who provide rebate coupons for compact fluorescent lamps. The sales from these retailers exceed the sales from the catalogue by three to one. Utilities, including PSNH, that participate in the CORE Program also work with seventy-five appliance retailers who provide rebates for Energy Star appliances.

The Small Business Initiatives Program is delivered by contractors who participate in a competitive bidding process. Alternatively, customers are free to use their own contractor and receive rebates for the measures installed. The large commercial and industrial programs also depend upon equipment vendors, building contractors or energy service companies to install the measures. Rebates provided to the customer for energy efficient devices often make the difference between a customer purchasing and installing a standard device or upgrading to the more efficient device.

Home Energy Assistance is a residential efficiency program offered to low income customers. The services are delivered for the most part, by the Community Action Agencies. This partnership leverages U.S. Department of Energy Home Weatherization Program Funds to ensure that the maximum amount of home heating efficiency is gained in these low income families' homes. The Home Energy Solutions and Energy Star Homes Programs are also offered to other residential customers and home builders. These programs each rely on local contractors for delivery of program services.

PSNH's System Benefits Charge revenues support the CORE Programs that supplement rather than supplant the small business sector that delivers energy efficient products and services. Existing businesses benefit from the subsidies provided through the programs. Because PSNH does not deliver the programs itself and relies upon local small businesses to provide services, there is no unfair competitive disadvantage to small business.

## B. Conclusion

PSNH is in compliance with 16 USC §2621(d)(7) as amended by the Energy Policy Act of 1992. It files a plan biennially, and the Commission conducts adjudicatory proceedings in evaluating that plan.

# XII. Assessment of the Plan's Long- and Short-Term Environmental, Economic, Energy Price, and Energy Supply Impact on the State

This section discusses the impact that environmental regulations and volatile energy prices have on PSNH and New Hampshire's economy and the initiatives PSNH is undertaking to minimize the cost impact.

## A. Environmental Regulations, Initiatives and Impacts

PSNH continuously monitors federal and state environmental regulations and legislative initiatives to determine their impact on PSNH's ownership of fossil-fuel generating assets. In addition to the Clean Air Act Amendments of 1990, there are numerous federal and state environmental regulations affecting PSNH. Some of the key regulations and initiatives include the federal Acid Rain Program, the Ozone Transport Region, the New Hampshire Clean Power Act, the Regional Haze Rule, the Clean Air Transport Rule, the Clean Air Mercury Rule and the Clean Water Act. The following sections discuss PSNH's compliance with the regulations and the impact of future environmental regulations.

### A.1. Sulfur Dioxide ($SO_2$)

As a result of the federal Acid Rain Program requirements, a national $SO_2$ emissions allowance market has evolved. PSNH has participated in this market as a purchaser of $SO_2$ allowances. In addition to the federal Acid Rain Program requirements, $SO_2$ is regulated under the New Hampshire Clean Power Act, RSA Chapter 125-O and Env-A 2900, a state cap and trade program. Purchasing allowances, in combination with burning lower-sulfur fuels, has been a cost effective means of complying with state and federal $SO_2$ requirements. This approach will continue to be employed until a wet flue gas desulphurization (FGD or "scrubber") is installed at Merrimack Station. With the passage of state legislation HB-1673 in June 2006, a scrubber is required to be installed at Merrimack Station for utilization on both Units 1 and 2 no later than July 1, 2013. This scrubber installation is required as a means to reduce mercury emissions, but has the additional benefit of reducing $SO_2$ emissions. Once installed, the scrubber will remove greater than 90 percent of the $SO_2$ emissions from MK1 and MK2. The scrubber is currently expected to be in-service one year early in mid-2012. In the interim, PSNH will continue to purchase allowances and burn low-sulfur fuels in order to comply with federal and state $SO_2$ requirements including RSA Chapter 125-O and Env-A 2900.

The $SO_2$ allowance market prices have been volatile. With a market as high as approximately $1,600 per ton in December 2005, $SO_2$ allowances have decreased to a current market price of less than $50 per ton. Implementation of the New Hampshire Clean Power Act in 2007 has increased the number of $SO_2$ allowances that PSNH is required to purchase.

PSNH's emissions management team monitors the inventory quantities, expected emissions and market prices to maintain an adequate inventory for annual compliance.

Historically, through proactive management PSNH has reduced the $SO_2$ emissions from its fossil-fueled fired generating stations with fuel switching and will significantly reduce SO2 emissions with the installation of the Merrimack Station scrubber.

### A.2. Nitrogen Oxide (NOx)

PSNH has installed NOx pollution control equipment and implemented operational controls on each electric generating unit regulated under the New Hampshire NOx Budget program, RSA Chapter 125-J and Env-A 3200, and the New Hampshire Clean Power Act, RSA Chapter 125-O and Env-A 2900. PSNH also has the option to purchase additional NOx allowances if necessary to comply with the requirements of the New Hampshire NOx Budget Program and the New Hampshire Clean Power Act. PSNH currently utilizes a combination of control equipment and market-based mechanisms to comply with the requirements of RSA Chapter 125-J and Env-A 3200, as well as RSA Chapter 125-O and Env-A 2900.

By way of background, the New Hampshire NOx Budget Program is a market-based budget (or cap) and trading program that was implemented in New Hampshire following the signing of the Ozone Transport Commission Memorandum of Understanding (OTC MOU) in 1994. The New Hampshire NOx Budget Program was designed to achieve ozone season (summer) NOx reductions greater than those required by the OTC MOU. Since the implementation of the program, the statewide annual budget has been decreased from 4,674 tons beginning in 1999, to 3,739 tons beginning in 2003, and 3,000 tons beginning in 2006. The caps result in significant reductions from the 1990 baseline level of 14,589 tons. Initially, only PSNH's electric generating units were regulated under the New Hampshire NOx Budget Program; however, since 2003, the program includes two new combined cycle natural gas power plants, Newington Energy and Granite Ridge LLC.

The New Hampshire NOx Budget Program is an output-based, updating allocation market-based cap and trade program. Under the program, regulated units receive a percentage of the statewide annual budget directly proportional to the unit's average generation produced during the prior two ozone seasons. Regulated units install NOx control technology or purchase additional allowances on an open market to satisfy annual compliance. By November 30th each year, a regulated unit must hold allowances in its account equal to the total tons of NOx emitted during the ozone season. The operation of NOx emissions control equipment at PSNH's generating stations, complemented by the purchase of NOx allowances, as necessary; remains a cost effective means of meeting state and federal NOx emissions reduction requirements.

The NOx emission allowance market, similar to the $SO_2$ market, has at times been volatile, but has been experiencing downward pricing pressure. This downward pressure resulted in NOx allowance prices falling during 2006 and 2007 from prices in excess of $2,100 per ton to current day prices of less than $400 per ton.

PSNH monitors the sale price of allowances and, as in the case of the $SO_2$ allowance market, the fuel purchasing group continually interacts with the allowance brokers on virtually a daily basis. PSNH will continue to monitor the NOx allowance market and make purchases for inventory, to build and use in future years should the sale price of allowances decrease below the cost of creating NOx reductions at its generating stations.

Through proactive management and the installation of emissions control equipment, PSNH has achieved significant reductions in NOx emissions from its fossil-fueled fired generating stations since 1995. PSNH will continue to maintain reductions of NOx through proactive management, operation and optimization of existing control equipment and potential installation of additional control equipment.

### A.3. Mercury (Hg)

At the federal level, EPA is currently gathering extensive, industry-wide, facility-specific information in preparation of drafting a Utility MACT rule expected by November 2011. Implementation is expected no sooner then 3 years after the rule is finalized.

Absent federal legislation, New Hampshire's legislature passed House Bill 1673, an amendment to the New Hampshire Clean Power Act, in June 2006 requiring a reduction in mercury emissions from the affected units as defined in the New Hampshire Clean Power Act. Only Merrimack and Schiller Stations are subject to the mercury requirements implemented under the New Hampshire Clean Power Act, specifically Merrimack Units 1 and 2, and Schiller Units 4 , 5, and 6. At the state level, trading of mercury emissions is not allowed under the New Hampshire Clean Power Act.

Under House Bill 1673, PSNH is required to install a scrubber at Merrimack Station for utilization on both Units 1 and 2 no later than June 2013. This scrubber installation is required as a means to reduce mercury emissions, but has the additional benefit of reducing sulfur dioxide emissions. In the interim, PSNH is required to test and implement, as practicable, mercury reduction control technologies or methods to achieve early reductions in mercury emissions. With the installation of the scrubber, Merrimack Station will be among the industry's cleanest coal plants, having retrofitted with both an SCR for NOx reductions and the scrubber for mercury and $SO_2$ reductions.

Specific to the HB1673 requirements, installation of the required scrubber at Merrimack station is well underway, and construction is expected to be completed by mid-2012. . PSNH has submitted the required mercury baseline data to the NHDES and continues to complete semi-annual stack testing as prescribed.

### A.4. Carbon Dioxide ($CO_2$)

New Hampshire was the first in the nation to limit $CO_2$ emissions as required by the Phase I cap established under the New Hampshire Clean Power Act. Phase II was established in June 2008, when New Hampshire passed legislation to participate in a regional $CO_2$ program, the Regional Greenhouse Gas Initiative, RGGI. The legislation set an auction clearing price of $6 per $CO_2$ allowance in 2009, above which all auction proceeds will be rebated to customers. Proceeds below the threshold are to be used for demand response and energy efficiency programs. The NHPUC's Sustainability Energy Division was created in 2008 and currently manages the RGGI auction proceeds.

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by ten northeastern and Mid-Atlantic States, including Connecticut, New Hampshire, and Massachusetts, to develop a regional program for stabilizing and reducing carbon dioxide ($CO_2$) emissions from fossil fuel-fired electric generating plants. RGGI stabilizes $CO_2$ emissions at 2009 levels and reduce them by 10 percent from these levels by 2018. RGGI is composed of individual $CO_2$ budget trading programs in each of the participating states. Each participating state's $CO_2$ budget trading program establishes its respective share of the regional cap, and each state will sell $CO_2$ allowances in a number equivalent to its portion of the regional cap. Each $CO_2$ allowance represents a permit to emit one ton of $CO_2$ in a specific year. The RGGI states sell $CO_2$ allowances primarily through regional auctions. Regulated power generators are able to purchase $CO_2$ allowances issued by any of the participating states to demonstrate compliance with the RGGI program of the state governing their generating plants. Taken together, the individual participating state programs function as a single regional compliance market for carbon emissions. RGGI's first auction occurred in September 2008. Since then RGGI has conducted a total of 11 quarterly auctions and RGGI allowances are also traded in a developed secondary market. There is currently no commercially available air pollution control equipment to control $CO_2$ emissions, although development and testing of such technology is ongoing.

The New Hampshire Clean Power Act also allowed PSNH to earn bonus $CO_2$ allowances. Under the provisions of RSA Chapter 125-O, NH DES ARD provides $CO_2$ allowances to PSNH for qualifying energy efficiency and new renewable energy projects. The installation of a wood-fired boiler at Schiller Station, Northern Wood Power, qualified as a renewable energy project under New Hampshire air pollution control regulations. Efficiency projects at Smith Hydro, Newington Station and Merrimack Station were also completed and qualified as projects available to earn bonus $CO_2$ allowances. With New Hampshire's transition to RGGI as a phase II effort, the Northern Wood Power was awarded early reduction allowances. The value of the bonus allowances awarded to PSNH by NHDES is being contested before the New Hampshire Air Resources Council.

As described by RGGI, "early reduction allowances (ERA) are intended to provide an incentive for facilities to take actions to reduce $CO_2$ emissions sooner than otherwise would be required by granting allowances for qualifying emissions reductions made before the $CO_2$ Budget Trading Program start date. ERAs are awarded directly to the $CO_2$ budget source, are not included in the auction, and are in addition to the cap. To be eligible to receive ERAs, a $CO_2$ budget source must submit an ERA application no later than May 1, 2009." PSNH submitted the necessary documentation as required by HB1673 and Northern Wood Power earned approximately 1 million ERAs. These ERAs were deducted from the earned $CO_2$ allowances awarded as part of the NHCPA.

PSNH anticipates that its generating units will emit between 3.5 million and 5 million tons of $CO_2$ per year after taking into account the operation of PSNH's Northern Wood Power wood-burning generating plant, which under the RGGI formula, decreased PSNH's responsibility for reducing fossil-fired $CO_2$ emissions by approximately 425,000 tons per year, or about ten percent. New Hampshire legislation provides up to 2.5 million banked $CO_2$ allowances per year for PSNH's fossil fueled generating plants during the 2009 to 2011 compliance period. These banked $CO_2$ allowances will initially comprise about one-half of the yearly $CO_2$ allowances required for PSNH's generating plants to comply with RGGI, and such banked allowances will decrease over time. PSNH expects to satisfy its remaining RGGI requirements by purchasing $CO_2$ allowances at auction or in the secondary market.

It is possible that a federal cap-and-trade program will replace the RGGI program in the coming years, which could well jeopardize the state energy efficiency fund dependent on RGGI auction proceeds, but at this point, it is impossible to predict the scope and content of such a law.

## A.5. Regional Haze Rule

The Regional Haze Rule was originally introduced by EPA in 1999 to improve the visibility in 156 national parks and wilderness areas. The rule applies to the emissions of $SO_2$, $NO_X$, volatile organic compounds (VOCs), and particulate matter (PM). In 2005, the EPA issued the final Best Available Retrofit Technology (BART) rule, requiring facilities built between 1962 and 1977 and that have the potential to emit more than 250 tons of any visibility-impairing pollutant to use BART. In 2006, the EPA amended this rule to allow facilities to use an emissions trading program to satisfy requirements under the regional haze rule, provided that the emissions reduction resulting from the trading program meets or exceeds the visibility improvements under BART.

New Hampshire has submitted the required State Implementation Plan. EPA has provided comments and the process is continuing, although certainly the operation of the Merrimack Station scrubber system will be critical in meeting BART goals.

## A.6. Clean Water Act of 1972

**Section §316(a) – Thermal Discharge**

The Clean Water Act requires a facility to "assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water." The discharge of pollutants, including heat, is specifically governed by National Pollutant Discharge Elimination System (NPDES) permits.

EPA is in the process of reissuing Merrimack Station's NPDES permit. To date, Merrimack Station has effectively controlled the release of heat to the river by discharging water through a cooling canal. The canal, in concert with floating "power spray modules" operated within specific guidelines on a seasonal basis, minimizes the thermal output of the cooling water into the river.

PSNH performs fisheries studies and river modeling in order to provide information to the agencies and to confirm the continued health of the aquatic ecosystem. This data collection as well as other information has been provided to EPA in response to multiple information requests. The data gathered to date demonstrates that the thermal discharge from the plant has not had an adverse environmental effect on the aquatic population over the course of plant operations. In fact, thermal and biological monitoring data collected by PSNH in Hooksett Pool and upper Amoskeag Pool since 1967 provides no historical evidence that the Station's thermal discharge (1) may reasonably be considered to have caused any prior appreciable harm to the balanced indigenous population or community of shellfish, fish and wildlife that reside within, or are migratory through, the Merrimack River in the sphere of influence of Station's hydrothermal regime, or (2) in the future, will not assure the continued protection and propagation of the aquatic ecosystem.

Similarly, at Schiller Station, fisheries studies and river monitoring support continuation of current operating conditions.

At this point, PSNH cannot predict if more stringent thermal restrictions will be imposed by EPA.

**Section §316(b) – Withdrawal of Cooling Water**

Section §316(b) of the Clean Water Act of 1972 requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. EPA has issued a series of rules designed to protect aquatic organisms from being killed or injured by impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical or chemical stresses).

The rulemaking was being implemented in three phases:

- Phase I rule, promulgated in 2001, covers new facilities.
- Phase II rule, promulgated in 2004, covers large existing electric generating plants.
- Phase III rule, proposed November 1, 2004, covers small existing facilities.

PSNH's three fossil stations fall under the Phase II Rule.

However, substantial uncertainty has persisted (and continues to exist) regarding EPA's currently suspended Phase II Rule for existing facilities and the cost-benefit test (which was the subject of litigation through the United States Supreme Court).

On January 25, 2007, the United States Court of Appeals for the Second Circuit issued its decision in a lawsuit challenging the Phase II Rule (known as "*Riverkeeper II*"), remanding key components of the Rule to EPA for reconsideration. Shortly thereafter, EPA formally suspended the Phase II Rule and directed the EPA regional offices to develop permit requirements relating to cooling water intake structures on a site-specific best professional judgment basis, requiring facilities to use the best technology available to minimize adverse environmental impact from their cooling water intake structures. However, since that time, the *Riverkeeper II* decision has been successfully challenged at the United States Supreme Court (*Entergy Corp. v. Riverkeeper, Inc.*), and importantly, the Supreme Court concluded that EPA acted within its authority under CWA Section 316(b) when it used cost-benefit analysis to establish national performance standards for cooling water intake structures at certain existing electric generating plants (including Merrimack Station) and to allow for site-specific variances from those standards based on cost-benefit considerations, in the Rule. Thus, while EPA Headquarters technically has suspended most of the Rule that suspension responded to the litigation surrounding the Rule, and was effectively resolved by the Supreme Court decision.

In the meantime, PSNH continues to develop and provide much of the same information to EPA as would have been required under the Rule, including impingement and entrainment monitoring data. PSNH has also submitted its Comprehensive Demonstration Studies (CDS) as required by the Rule. The purpose of the CDS was to characterize impingement mortality and entrainment, describe the operation of the cooling water intake structures, and confirm that technologies and/or operational measures that had been selected and installed, or would be installed within an approved timeframe, would comply with the Rule.

Again with the suspension of the rule, EPA has stated that all permits for Phase II facilities will be reviewed by the permitting agencies using a Best Professional Judgment (BPJ) basis. EPA has not suspended 40 CFR 125.90(b) which requires that permitting authorities develop BPJ controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact.

At this time, a high degree of regulatory uncertainty remains and PSNH cannot predict the outcome. PSNH could be required to take certain actions determined to be potential best technology available for Merrimack Station based on cost, biological benefits, and risks, ranging from installing an improved fish return system with additional monitoring requirements to investing in wedgewire screens with upgraded fish return systems.

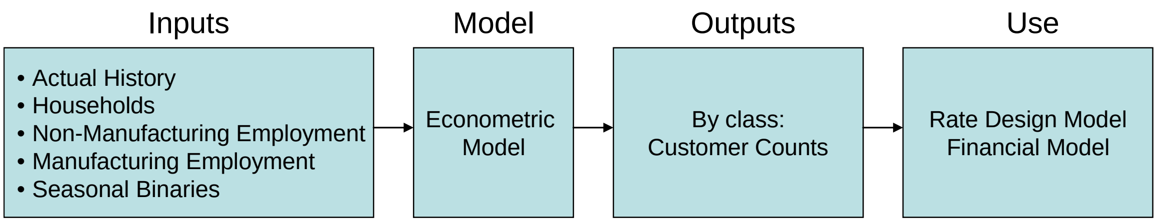
At Schiller Station, PSNH is continuing to research the efficacy of wedgewire screens. PSNH is providing this critical information to EPA to support the best technology available determination. PSNH's existing submittals already establish support for a best technology available determination in favor of wedgewire screens.

In summary, air, water, and land-use regulations are frequently reviewed by the regulators, as is the case currently. The outcome of these reviews and the impact of any new regulations are difficult to predict and any costs associated with such regulation even more difficult to predict.

# XIII. Appendix A – Financial and Business Planning Forecasting Models

This appendix provides a more detailed discussion of the methodologies to forecast customer counts, delivery energy sales, system peak load, and delivery hourly loads for use in financial and business planning.

## A. Customer Counts

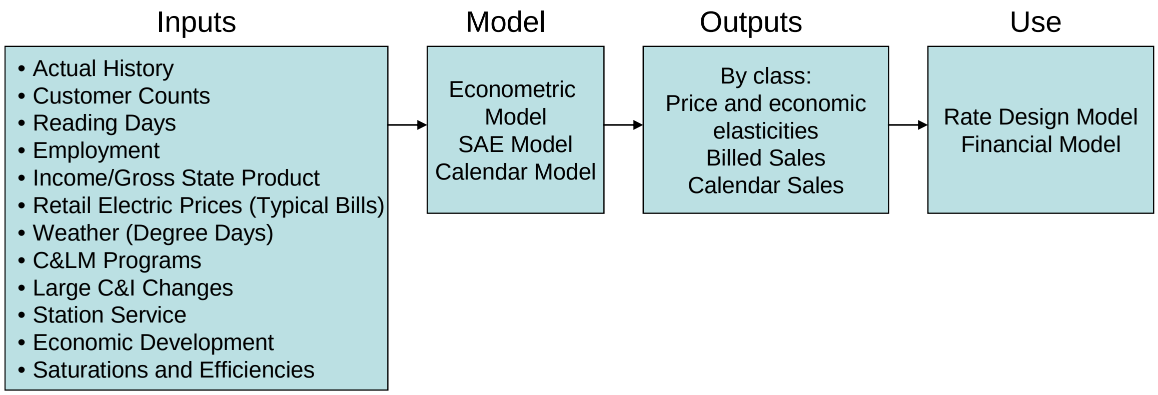



The class customer count equations were estimated using historical data from January 1998 to March 2010, depending on the class of customer. Separate econometric models are used to forecast customers, with customers as a function of households (residential), non-manufacturing employment (commercial), manufacturing employment (industrial), or a trend (streetlighting). The equations below describe the independent variables used to develop the customer count class models.

**ResCustCount**$_m$ = f(EconDemo$_m$, MonBinary, CIIBinary, LagDependent)
**ComCustCount**$_m$ = f(EconDemo$_m$, Binary, LagDependent)
**IndCustCount**$_m$ = f(EconDemo$_{m,}$ Binary, LagDependent)
**StlCustCount**$_m$ = f(ResCust $_{m,}$, CIIBinary, Binary)

where:
m = Month
EconDemo$_m$ = Monthly economic and demographic variables specific to the class (i.e., households, non-manufacturing employment, manufacturing employment)
MonBinary = Monthly binary variables
Binary = Binary variable to adjust for data anomalies
CIIBinary = Binary variable to adjust for conversion to C2 billing system in 2008
ResCust = Residential Customers
LagDependent = Lagged dependent variable

## B. Delivery Energy Sales




### Methodology

PSNH's monthly delivery energy forecast is developed by class and reflects local economic and demographic conditions. Economic and demographic forecasts for New Hampshire are produced based on a model developed by Moody's Economy.com for the state of New Hampshire and the United States. The sales forecast is developed by class by various end uses and incorporates assumptions to reflect customers' response to price changes, conservation programs, economic development efforts and other known changes. Sales forecasts are disaggregated by end use to study detailed trends that affect energy consumption and to provide input to the hourly energy and peak load forecasts.

**Step 1: Econometric Model**

**ResUsePerDay**$_m$ = f(HDD_RD$_m$, CDD_RD$_m$, Price$_m$, EconDemo$_m$, LagDependent)
**ComUsePerDay**$_m$ = f(HDD_RD$_m$, CDD_RD$_m$, Price$_m$, EconDemo$_m$)
**IndUse**$_m$ = f(CDD$_m$, RD$_m$, Price$_m$, EconDemo$_m$, Binary, LagDependent)
**StlUse**$_m$ = f(ResCust$_m$, MonBinary$_m$, Binary)

where:
m = Month
HDD_RD$_m$ = Heating degree days per reading day per month
CDD_RD$_m$ = Cooling degree days per reading day per month
HDD$_m$ = Heating degree days per month
CDD$_m$ = Cooling degree days per month
RD$_m$ = Reading days per month
Price$_m$ = 12 month moving average typical bill per month
EconDemo$_m$ = Monthly economic and demographic variables specific to the class (i.e., income, non-manufacturing employment, manufacturing employment, manufacturing gross state product)
MonBinary = Monthly binary variables
CVECBinary = Binary variable to adjust for CVEC acquisition
Binary = Binary variable to adjust for data anomalies
LagDependent = Lagged dependent variable

The end result of the models described above is class specific elasticities to use in SAE models for residential and commercial classes and Trend sales for industrial and streetlighting classes. SAE models are not available for the industrial and streetlighting classes.

**Step 2: Statistically Adjusted End-Use Model**

In 2006, the Company joined Itron's Energy Forecasting Group and began using their Statistically Adjusted End-Use Models (SAE) for the residential and commercial classes. Itron, a nationally recognized expert in end-use forecasting, developed the SAE methodology, which is being used by many electric and gas utilities around the country. The SAE models use regional end-use data from the U.S. Department of Energy's Energy Information Administration to develop independent variables that are used in traditional econometric models.

The SAE modeling framework begins by defining energy use ($Use_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathbf{Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m}}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathbf{Use_{y,m} = b_1 \times XHeat_{y,m} + b_2 \times XCool_{y,m} + b_3 \times XOther_{y,m}}$$

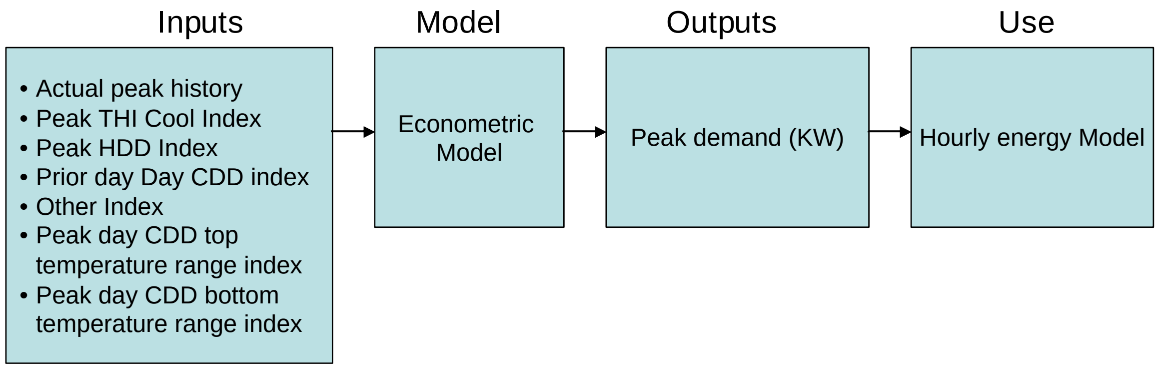
Here, $XHeat_{y,m}$, $XCool_{y,m}$ and $XOther_{y,m}$ are explanatory variables constructed from end-use information, dwelling, weather, economic and price data. The equations used to construct these X-variables maintain an end-use structure as the X-variables are the estimated usage levels for each of the major end uses. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors which scale the regional data to the Company's sales.

For the residential and commercial classes, Trend sales equal the number of customers times use per customer from the SAE models. The industrial and streetlighting sales Trend forecasts are based on traditional econometric models because SAE models are not available for the industrial or streetlighting classes.

**Step 3: Adjustments to Forecast**

The final step in developing the Reference case forecast is to make adjustments either up or down to account for Conservation and Load Management losses, Economic Development gains, Large Commercial and Industrial gains or losses, Seabrook Station Service gains, and a final adjustment to convert billed sales into calendar sales. The end result is the Reference forecast.

## C. Peak Load Demand




**<u>Methodology</u>**

The Reference Peak Demand forecast is created in order to develop the hourly energy forecast. It is not used for system planning purposes. The forecast for system planning is described in greater detail in section III.D. The forecasted peaks are derived from an econometric model where monthly peaks are a function of weather and Trend forecast sales by end use. The resulting peak forecast is not explicitly adjusted for C&LM and economic development assumptions because they are assumed to be included in the peak trend.

The Reference or Base Case Peak Demand forecast, as a 50/50 forecast, assumes normal weather throughout the year, with normal peak-producing weather episodes in each season. The forecasted 24 hour mean daily temperature for the summer peak day is 79° Fahrenheit (°F) and for the winter peak day is 5° Fahrenheit (°F) and is based on the average peak-day temperatures from 1977-2006.

The historical 24 hour peak-day mean temperatures range from 76° F to 84° F in the summer and from -9° F to 25° F in the winter with deviations from the average peak-day temperatures being random, recurring and unpredictable occurrences. For example, the lowest summer peak-day mean temperature occurred in 2000, while the highest summer peak-day mean temperature occurred in 2001. The highest winter peak-day mean temperature occurred in 1993 and the lowest winter peak-day mean temperature occurred in 2001. This variability of peak-producing weather means that over the forecast period there will be years when the actual peaks will be significantly above or below forecasted peaks.

The following econometric equation is used to derive the non-coincident peak demand forecast:

$$\mathbf{NCPeak_{y,m} = b_1 \times THI\_I\_Cool_{y,m} + b_2 \times HDD\_I\_Heat_{y,m} + b_3 \times Yest\_I\_CDD_{y,m} + b_4 \times I\_Other_{y,m} + b_5 \times CDD\_I\_Cool\_Top_{y,m} + b_6 \times CDD\_I\_Cool\_First_{y,m}}$$

where:
y = Year
m = Month

$THI\_I\_Cool_{y,m}$ = Temperature-Humidity index on the day of the monthly peak
$HDD\_I\_Heat_{y,m}$ = Heating DD index on the day of the monthly peak
$Yest\_I\_CDD_{y,m}$ = Cooling DD index on the day before the peak day
$I\_Other_{y,m}$ = Other index
$CDD\_I\_Cool\_Top_{y,m}$ = Cooling degree index on day of monthly peak; top break point
$CDD\_I\_Cool\_First_{y,m}$ = Cooling DD index on day of monthly peak; first break point

## D. Hourly Energy Use

The hourly energy forecast is used as an input into the supplemental energy purchase forecast. To develop the hourly energy forecast, the monthly sales and monthly peaks are combined into a scaling model and the shape of the line is adjusted so that the hourly loads add up to the monthly energy from the Reference Delivery Energy Sales forecast and the highest hour matches the monthly peaks from the Reference Peak Demand forecast.

The hourly loads for each year include company use, wholesale requirements, and losses and are divided by a delivery efficiency factor of 0.945 to convert into a pool transmission level. This is the base forecast of system electrical energy requirements or output and is the amount of energy which must be supplied by generating plants or power purchases to serve the loads on the system.

# XIV. Appendix B – Financial and Business Planning Forecast Scenarios

This appendix provides a more detailed discussion of the scenario analysis for the forecasted customer counts, delivery energy sales, system peak load, and hourly load.

## A. Customer Counts Scenario Analysis

- The Base Case Customer forecast is based on an average annual growth rate of 0.7 percent for households, 1.9 percent for non-manufacturing employment, and -0.4 percent for manufacturing employment.
- The Low Growth Case Customer forecast is based on an average annual growth rate of 0.4 percent for households, 1.2 percent for non-manufacturing employment, and -1.7 percent for manufacturing employment.
- The High Growth Case Customer forecast is based on an average annual growth rate of 0.9 percent for households, 2.5 percent for non-manufacturing employment, and 0.8 percent for manufacturing employment.

| PSNH Annual Customer History and Forecast - Base Case | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Res** | **% Chg** | **Com** | **% Chg** | **Ind** | **% Chg** | **Stl** | **% Chg** | **Total** | **% Chg** |
| ***History*** | | | | | | | | | | |
| 2005 | 403,088 | | 68,232 | | 2,768 | | 563 | | 474,650 | |
| 2006 | 413,980 | 2.7% | 69,528 | 1.9% | 2,761 | -0.3% | 554 | -1.6% | 486,823 | 2.6% |
| 2007 | 417,420 | 0.8% | 70,341 | 1.2% | 2,770 | 0.4% | 564 | 1.8% | 491,095 | 0.9% |
| 2008 | 418,110 | 0.2% | 70,822 | 0.7% | 2,979 | 7.5% | 932 | 65.4% | 492,843 | 0.4% |
| 2009 | 417,670 | -0.1% | 70,984 | 0.2% | 3,134 | 5.2% | 1,399 | 50.0% | 493,187 | 0.1% |
| **Compound Annual Growth Rates (2005-2009)** | | | | | | | | | | |
| | 0.9% | | 1.0% | | 3.2% | | 25.6% | | 1.0% | |
| ***Forecast*** | | | | | | | | | | |
| 2010 | 419,571 | 0.5% | 71,736 | 1.1% | 3,095 | -1.3% | 1,456 | 4.0% | 495,857 | 0.5% |
| 2011 | 420,865 | 0.3% | 72,419 | 1.0% | 3,061 | -1.1% | 1,353 | -7.1% | 497,697 | 0.4% |
| 2012 | 423,420 | 0.6% | 73,457 | 1.4% | 3,050 | -0.4% | 1,358 | 0.4% | 501,285 | 0.7% |
| 2013 | 426,397 | 0.7% | 74,842 | 1.9% | 3,046 | -0.2% | 1,365 | 0.5% | 505,649 | 0.9% |
| 2014 | 429,283 | 0.7% | 76,282 | 1.9% | 3,042 | -0.1% | 1,371 | 0.5% | 509,978 | 0.9% |
| 2015 | 432,037 | 0.6% | 77,614 | 1.7% | 3,039 | -0.1% | 1,377 | 0.4% | 514,067 | 0.8% |
| **Compound Annual Growth Rates (2009-2015)** | | | | | | | | | | |
| | 0.6% | | 1.5% | | -0.5% | | -0.3% | | 0.7% | |

| PSNH Annual Customer History and Forecast - Low Growth Case | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Res** | **% Chg** | **Com** | **% Chg** | **Ind** | **% Chg** | **Stl** | **% Chg** | **Total** | **% Chg** |
| ***History*** | | | | | | | | | | |
| 2005 | 403,088 | | 68,232 | | 2,768 | | 563 | | 474,650 | |
| 2006 | 413,980 | 2.7% | 69,528 | 1.9% | 2,761 | -0.3% | 554 | -1.6% | 486,823 | 2.6% |
| 2007 | 417,420 | 0.8% | 70,341 | 1.2% | 2,770 | 0.4% | 564 | 1.8% | 491,095 | 0.9% |
| 2008 | 418,110 | 0.2% | 70,822 | 0.7% | 2,979 | 7.5% | 932 | 65.4% | 492,843 | 0.4% |
| 2009 | 417,670 | -0.1% | 70,984 | 0.2% | 3,134 | 5.2% | 1,399 | 50.0% | 493,187 | 0.1% |
| **Compound Annual Growth Rates (2005-2009)** | | | | | | | | | | |
| | 0.9% | | 1.0% | | 3.2% | | 25.6% | | 1.0% | |
| ***Forecast*** | | | | | | | | | | |
| 2010 | 419,023 | 0.3% | 71,725 | 1.0% | 3,095 | -1.3% | 1,454 | 4.0% | 495,296 | 0.4% |
| 2011 | 419,845 | 0.2% | 72,387 | 0.9% | 3,061 | -1.1% | 1,351 | -7.1% | 496,644 | 0.3% |
| 2012 | 422,062 | 0.5% | 73,404 | 1.4% | 3,050 | -0.4% | 1,355 | 0.4% | 499,872 | 0.6% |
| 2013 | 424,699 | 0.6% | 74,768 | 1.9% | 3,045 | -0.1% | 1,361 | 0.4% | 503,873 | 0.8% |
| 2014 | 427,242 | 0.6% | 76,186 | 1.9% | 3,042 | -0.1% | 1,367 | 0.4% | 507,836 | 0.8% |
| 2015 | 429,651 | 0.6% | 77,497 | 1.7% | 3,039 | -0.1% | 1,372 | 0.4% | 511,558 | 0.7% |
| **Compound Annual Growth Rates (2009-2015)** | | | | | | | | | | |
| | 0.5% | | 1.5% | | -0.5% | | -0.3% | | 0.6% | |

| PSNH Annual Customer History and Forecast - High Growth Case | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Res** | **% Chg** | **Com** | **% Chg** | **Ind** | **% Chg** | **Stl** | **% Chg** | **Total** | **% Chg** |
| ***History*** | | | | | | | | | | |
| 2005 | 403,088 | | 68,232 | | 2,768 | | 563 | | 474,650 | |
| 2006 | 413,980 | 2.7% | 69,528 | 1.9% | 2,761 | -0.3% | 554 | -1.6% | 486,823 | 2.6% |
| 2007 | 417,420 | 0.8% | 70,341 | 1.2% | 2,770 | 0.4% | 564 | 1.8% | 491,095 | 0.9% |
| 2008 | 418,110 | 0.2% | 70,822 | 0.7% | 2,979 | 7.5% | 932 | 65.4% | 492,843 | 0.4% |
| 2009 | 417,670 | -0.1% | 70,984 | 0.2% | 3,134 | 5.2% | 1,399 | 50.0% | 493,187 | 0.1% |
| **Compound Annual Growth Rates (2005-2009)** | | | | | | | | | | |
| | 0.9% | | 1.0% | | 3.2% | | 25.6% | | 1.0% | |
| ***Forecast*** | | | | | | | | | | |
| 2010 | 420,121 | 0.6% | 71,746 | 1.1% | 3,095 | -1.3% | 1,457 | 4.1% | 496,418 | 0.7% |
| 2011 | 421,889 | 0.4% | 72,450 | 1.0% | 3,061 | -1.1% | 1,355 | -7.0% | 498,755 | 0.5% |
| 2012 | 424,786 | 0.7% | 73,510 | 1.5% | 3,051 | -0.3% | 1,361 | 0.5% | 502,708 | 0.8% |
| 2013 | 428,110 | 0.8% | 74,919 | 1.9% | 3,046 | -0.1% | 1,369 | 0.5% | 507,443 | 0.9% |
| 2014 | 431,345 | 0.8% | 76,382 | 2.0% | 3,043 | -0.1% | 1,375 | 0.5% | 512,145 | 0.9% |
| 2015 | 434,452 | 0.7% | 77,737 | 1.8% | 3,040 | -0.1% | 1,382 | 0.5% | 516,611 | 0.9% |
| **Compound Annual Growth Rates (2009-2015)** | | | | | | | | | | |
| | 0.7% | | 1.5% | | -0.5% | | -0.2% | | 0.8% | |

## B. Delivery Energy Sales Scenario Analysis

- The Base Case Delivery Energy Sales forecast is based on an average annual growth rate of 4.9 percent for real personal income, 1.9 percent for non-manufacturing employment, -0.4 percent for manufacturing employment, and 4.7 percent for real manufacturing gross state product.
- The Low Growth Case Delivery Energy Sales forecast is based on an average annual growth rate of 0.4 percent for households, 1.2 percent for non-manufacturing employment, -1.7 percent for manufacturing employment, and 3.0 percent for real manufacturing gross state product. For a description of how electric prices were changed see section B.3.2
- The High Growth Case Delivery Energy Sales forecast is based on an average annual growth rate of 0.9 percent for households, 2.5 percent for non-manufacturing employment, 0.8 percent for manufacturing employment, and 6.4 percent for real manufacturing gross state product. For a description of how electric prices were changed see section B.3.2

| PSNH Annual Calendar Sales History and Forecast (GWH) - Base Case | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Res** | **% Chg** | **Com** | **% Chg** | **Ind** | **% Chg** | **Stl** | **% Chg** | **Total** | **% Chg** |
| ***History (Weather Normalized)*** | | | | | | | | | | |
| 2005 | 3,102 | | 3,296 | | 1,592 | | 24 | | 8,014 | |
| 2006 | 3,118 | 0.5% | 3,341 | 1.4% | 1,574 | -1.1% | 23 | -5.4% | 8,057 | 0.5% |
| 2007 | 3,164 | 1.5% | 3,394 | 1.6% | 1,524 | -3.2% | 24 | 4.9% | 8,106 | 0.6% |
| 2008 | 3,132 | -1.0% | 3,380 | -0.4% | 1,442 | -5.4% | 25 | 2.2% | 7,978 | -1.6% |
| 2009 | 3,150 | 0.6% | 3,357 | -0.7% | 1,339 | -7.1% | 24 | -3.2% | 7,870 | -1.4% |
| **Compound Annual Growth Rates (2005-2009)** | | | | | | | | | | |
| | 0.4% | | 0.5% | | -4.2% | | -0.5% | | -0.5% | |
| ***Forecast*** | | | | | | | | | | |
| 2010 | 3,140 | -0.3% | 3,286 | -2.1% | 1,293 | -3.4% | 24 | 1.9% | 7,743 | -1.6% |
| 2011 | 3,156 | 0.5% | 3,316 | 0.9% | 1,291 | -0.2% | 25 | 0.5% | 7,788 | 0.6% |
| 2012 | 3,205 | 1.5% | 3,348 | 1.0% | 1,300 | 0.7% | 25 | 0.3% | 7,877 | 1.1% |
| 2013 | 3,242 | 1.1% | 3,352 | 0.1% | 1,285 | -1.2% | 25 | 0.3% | 7,903 | 0.3% |
| 2014 | 3,298 | 1.7% | 3,408 | 1.7% | 1,264 | -1.6% | 25 | 0.3% | 7,995 | 1.2% |
| 2015 | 3,337 | 1.2% | 3,453 | 1.3% | 1,250 | -1.1% | 25 | 0.3% | 8,065 | 0.9% |
| **Compound Annual Growth Rates (2009-2015)** | | | | | | | | | | |
| | 1.0% | | 0.5% | | -1.1% | | 0.6% | | 0.4% | |

| PSNH Annual Calendar Sales History and Forecast (GWH) - Low Growth Case | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Res** | **% Chg** | **Com** | **% Chg** | **Ind** | **% Chg** | **Stl** | **% Chg** | **Total** | **% Chg** |
| ***History (Weather Normalized)*** | | | | | | | | | | |
| 2005 | 3,102 | | 3,296 | | 1,592 | | 24 | | 8,014 | |
| 2006 | 3,118 | 0.5% | 3,341 | 1.4% | 1,574 | -1.1% | 23 | -5.4% | 8,057 | 0.5% |
| 2007 | 3,164 | 1.5% | 3,394 | 1.6% | 1,524 | -3.2% | 24 | 4.9% | 8,106 | 0.6% |
| 2008 | 3,132 | -1.0% | 3,380 | -0.4% | 1,442 | -5.4% | 25 | 2.2% | 7,978 | -1.6% |
| 2009 | 3,150 | 0.6% | 3,357 | -0.7% | 1,339 | -7.1% | 24 | -3.2% | 7,870 | -1.4% |
| **Compound Annual Growth Rates (2005-2009)** | | | | | | | | | | |
| | 0.4% | | 0.5% | | -4.2% | | -0.5% | | -0.5% | |
| ***Forecast*** | | | | | | | | | | |
| 2010 | 3,134 | -0.5% | 3,284 | -2.2% | 1,290 | -3.7% | 24 | 1.9% | 7,731 | -1.8% |
| 2011 | 3,126 | -0.3% | 3,287 | 0.1% | 1,274 | -1.3% | 25 | 0.4% | 7,711 | -0.3% |
| 2012 | 3,147 | 0.7% | 3,291 | 0.1% | 1,268 | -0.4% | 25 | 0.2% | 7,731 | 0.3% |
| 2013 | 3,167 | 0.6% | 3,283 | -0.2% | 1,243 | -1.9% | 25 | 0.3% | 7,718 | -0.2% |
| 2014 | 3,209 | 1.3% | 3,329 | 1.4% | 1,215 | -2.3% | 25 | 0.3% | 7,777 | 0.8% |
| 2015 | 3,234 | 0.8% | 3,365 | 1.1% | 1,193 | -1.8% | 25 | 0.3% | 7,818 | 0.5% |
| **Compound Annual Growth Rates (2009-2015)** | | | | | | | | | | |
| | 0.4% | | 0.0% | | -1.9% | | 0.6% | | -0.1% | |

| PSNH Annual Calendar Sales History and Forecast (GWH) - High Growth Case | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Res** | **% Chg** | **Com** | **% Chg** | **Ind** | **% Chg** | **Stl** | **% Chg** | **Total** | **% Chg** |
| ***History (Weather Normalized)*** | | | | | | | | | | |
| 2005 | 3,102 | | 3,296 | | 1,592 | | 24 | | 8,014 | |
| 2006 | 3,118 | 0.5% | 3,341 | 1.4% | 1,574 | -1.1% | 23 | -5.4% | 8,057 | 0.5% |
| 2007 | 3,164 | 1.5% | 3,394 | 1.6% | 1,524 | -3.2% | 24 | 4.9% | 8,106 | 0.6% |
| 2008 | 3,132 | -1.0% | 3,380 | -0.4% | 1,442 | -5.4% | 25 | 2.2% | 7,978 | -1.6% |
| 2009 | 3,150 | 0.6% | 3,357 | -0.7% | 1,339 | -7.1% | 24 | -3.2% | 7,870 | -1.4% |
| **Compound Annual Growth Rates (2005-2009)** | | | | | | | | | | |
| | 0.4% | | 0.5% | | -4.2% | | -0.5% | | -0.5% | |
| ***Forecast*** | | | | | | | | | | |
| 2010 | 3,146 | -0.1% | 3,287 | -2.1% | 1,297 | -3.2% | 24 | 2.0% | 7,754 | -1.5% |
| 2011 | 3,180 | 1.1% | 3,343 | 1.7% | 1,308 | 0.9% | 25 | 0.5% | 7,856 | 1.3% |
| 2012 | 3,242 | 1.9% | 3,399 | 1.7% | 1,329 | 1.6% | 25 | 0.3% | 7,995 | 1.8% |
| 2013 | 3,284 | 1.3% | 3,412 | 0.4% | 1,323 | -0.5% | 25 | 0.4% | 8,043 | 0.6% |
| 2014 | 3,350 | 2.0% | 3,478 | 1.9% | 1,312 | -0.9% | 25 | 0.4% | 8,164 | 1.5% |
| 2015 | 3,400 | 1.5% | 3,532 | 1.6% | 1,305 | -0.5% | 25 | 0.3% | 8,262 | 1.2% |
| **Compound Annual Growth Rates (2006-2012)** | | | | | | | | | | |
| | 1.3% | | 0.8% | | -0.4% | | 0.6% | | 0.8% | |

## C. Peak Demand Scenario Analysis

- The Reference Plan Peak Demand forecast is based on normal peak day weather (80ºF mean daily summer temperature, 5ºF mean daily winter temperature).
- The High Peak Demand forecasts are based on the weather that occurred on the 2001 summer peak day (84ºF mean daily temperature) and on the 1993 winter peak day (-9ºF mean daily temperature).
- The Low Peak Demand forecasts are based on the weather that occurred on the 2000 summer peak day (73ºF mean daily temperature) and on the 2001 winter peak day (27ºF mean daily temperature).

| 50/50 Case and Extreme Weather Scenarios for Summer Peak | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Net Electrical Energy Output Requirements | | Reference Plan (50/50 Case) | | | Extreme Hot Scenario | | | Extreme Cool Scenario | | |
| Year | Output | Annual Change | Peak | Annual Change | Load Factor | Peak | Annual Change | Load Factor | Peak | Annual Change | Load Factor |
| | GWH | (%) | MW | (%) | (2) | MW | (%) | (2) | MW | (%) | (2) |
| ***History*** | | | | | | | | | | | |
| 2005 | 8,655 | | 1,729 | | 0.570 | | | | | | |
| 2006 | 8,489 | -1.9% | 1,786 | 3.3% | 0.541 | | | | | | |
| 2007 | 8,595 | 1.2% | 1,684 | -5.8% | 0.581 | | | | | | |
| 2008 | 8,408 | -2.2% | 1,698 | 0.8% | 0.564 | | | | | | |
| 2009 | 8,138 | -3.2% | 1,617 | -4.8% | 0.573 | | | | | | |
| **Compound Rates of Growth (2005-2009)** | | | | | | | | | | | |
| | -1.5% | | -1.7% | | | | | | | | |
| ***History Normalized for Weather*** | | | | | | | | | | | |
| 2005 | 8,529 | | 1,670 | | 0.581 | | | | | | |
| 2006 | 8,511 | -0.2% | 1,650 | -1.2% | 0.587 | | | | | | |
| 2007 | 8,569 | 0.7% | 1,662 | 0.8% | 0.587 | | | | | | |
| 2008 | 8,460 | -1.3% | 1,619 | -2.6% | 0.595 | | | | | | |
| 2009 | 8,258 | -2.4% | 1,639 | 1.2% | 0.574 | | | | | | |
| **Compound Rates of Growth (2005-2009)** | | | | | | | | | | | |
| | -0.8% | | -0.6% | | | | | | | | |
| ***Forecast*** | | | | | | | | | | | |
| 2010 | 8,194 | -2.5% | 1,585 | -6.6% | 0.589 | 1,779 | 4.8% | 0.524 | 1,468 | -13.5% | 0.635 |
| 2011 | 8,241 | 0.6% | 1,594 | 0.6% | 0.589 | 1,788 | 0.5% | 0.525 | 1,477 | 0.6% | 0.635 |
| 2012 | 8,336 | 1.1% | 1,626 | 2.0% | 0.584 | 1,819 | 1.8% | 0.522 | 1,509 | 2.1% | 0.629 |
| 2013 | 8,363 | 0.3% | 1,648 | 1.3% | 0.578 | 1,841 | 1.2% | 0.517 | 1,531 | 1.5% | 0.622 |
| 2014 | 8,461 | 1.2% | 1,686 | 2.3% | 0.571 | 1,880 | 2.1% | 0.512 | 1,569 | 2.5% | 0.614 |
| 2015 | 8,534 | 0.9% | 1,712 | 1.5% | 0.568 | 1,906 | 1.4% | 0.510 | 1,595 | 1.6% | 0.609 |
| **Compound Rates of Growth (2009-2015)** | | | | | | | | | | | |
| | 0.8% | | 1.0% | | | 2.8% | | | -0.2% | | |
| **Normalized Compound Rates of Growth (2009-2015)** | | | | | | | | | | | |
| | 0.5% | | 0.7% | | | 2.5% | | | -0.5% | | |

Notes:
1. Sales plus losses and company use.
2. Load Factor = Output (MWh) / (8760 Hours X Season Peak (MW)).

| 50/50 Case and Extreme Weather Scenarios for Winter Peak | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Net Electrical Energy Output Requirements** | | **Reference Plan (50/50 Case)** | | | **Extreme Cold Scenario** | | | **Extreme Warm Scenario** | | | |
| Year | Output | Annual Change | Peak | Annual Change | Load Factor | Peak | Annual Change | Load Factor | Peak | Annual Change | Load Factor |
| | GWH | (%) | MW | (%) | (2) | MW | (%) | (2) | MW | (%) | (2) |
| ***History*** | | | | | | | | | | | |
| 2005 | 8,655 | | 1,419 | | 0.694 | | | | | | |
| 2006 | 8,489 | -1.9% | 1,418 | -0.1% | 0.682 | | | | | | |
| 2007 | 8,595 | 1.2% | 1,424 | 0.4% | 0.687 | | | | | | |
| 2008 | 8,408 | -2.2% | 1,417 | -0.5% | 0.675 | | | | | | |
| 2009 | 8,138 | -3.2% | 1,436 | 1.3% | 0.645 | | | | | | |
| **Compound Rates of Growth (2005-2009)** | | | | | | | | | | | |
| | -1.5% | | 0.3% | | | | | | | | |
| ***History Normalized for Weather*** | | | | | | | | | | | |
| 2005 | 8,529 | | 1,419 | | 0.684 | | | | | | |
| 2006 | 8,511 | -0.2% | 1,442 | 1.6% | 0.672 | | | | | | |
| 2007 | 8,569 | 0.7% | 1,388 | -3.7% | 0.703 | | | | | | |
| 2008 | 8,460 | -1.3% | 1,453 | 4.7% | 0.663 | | | | | | |
| 2009 | 8,258 | -2.4% | 1,471 | 1.2% | 0.639 | | | | | | |
| **Compound Rates of Growth (2005-2009)** | | | | | | | | | | | |
| | -0.8% | | 0.9% | | | | | | | | |
| ***Forecast*** | | | | | | | | | | | |
| 2010 | 8,194 | -2.5% | 1,362 | -5.1% | 0.685 | 1463 | 1.9% | 0.638 | 1219 | -15.2% | 0.766 |
| 2011 | 8,241 | 0.6% | 1,379 | 1.3% | 0.680 | 1480 | 1.2% | 0.634 | 1236 | 1.4% | 0.759 |
| 2012 | 8,336 | 1.1% | 1,396 | 1.2% | 0.680 | 1497 | 1.1% | 0.634 | 1252 | 1.4% | 0.758 |
| 2013 | 8,363 | 0.3% | 1,416 | 1.4% | 0.672 | 1517 | 1.3% | 0.628 | 1272 | 1.6% | 0.748 |
| 2014 | 8,461 | 1.2% | 1,442 | 1.8% | 0.668 | 1543 | 1.7% | 0.624 | 1298 | 2.0% | 0.742 |
| 2015 | 8,534 | 0.9% | 1,453 | 0.8% | 0.668 | 1554 | 0.8% | 0.625 | 1310 | 0.9% | 0.742 |
| **Compound Rates of Growth (2009-2015)** | | | | | | | | | | | |
| | 0.8% | | 0.2% | | | 1.3% | | | -1.5% | | |
| **Normalized Compound Rates of Growth (2009-2015)** | | | | | | | | | | | |
| | 0.5% | | -0.2% | | | 0.9% | | | -1.9% | | |

Notes:
1. Sales plus losses and company use.
2. Load Factor = Output (MWh) / (8,760 Hours X Season Peak (MW)).

# XV.Appendix C – Engineering Forecasts by Area

**2010 - SUMMER PEAK LOAD FORECAST**

| YEAR | Lakes Region (MW) | Lakes Region %Difference | Derry (MW) | Derry %Difference | Dover/Rochester (MW) | Dover/Rochester %Difference | Manchester (MW) | Manchester % Difference | Sunapee (MW) | Sunapee %Difference | Berlin/Lancaster (MW) | Berlin/Lancaster %Difference | Portsmouth (MW) | Portsmouth % Differen |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1994 | 114.8 | | 54.5 | | 116.3 | | 237.7 | | 30.7 | | 69.2 | | 138.5 | |
| 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% |
| 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% |
| 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% |
| 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% |
| 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% |
| 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% |
| 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% |
| 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% |
| 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% |
| 2004 | 155.0 | -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% |
| 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% |
| 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% |
| 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% |
| 2008 | 174.8 | 2.3% | 132.6 | -1.7% | 156.1 | -3.3% | 375.1 | 3.3% | 38.0 | -10.8% | 51.8 | -18.9% | 255.1 | 0.4% |
| 2009 | 165.6 | -5.2% | 122.0 | -8.0% | 156.8 | 0.5% | 343.7 | -8.4% | 38.6 | 1.4% | 47.0 | -9.2% | 236.6 | -7.3% |
| Compounded Growth Rate | | 4.24% | | 5.36% | | 4.26% | | 2.98% | | 1.71% | | -1.08% | | 5.42% |
| Projected Growth Rate | | 3.00% | | 4.00% | | 3.20% | | 3.75% | | 2.70% | | 0.50% | | 4.50% |
| 2010 | 196.3 | | 140.3 | | 174.5 | | 389.2 | | 43.8 | | 70.9 | | 279.5 | |
| 2011 | 202.2 | | 145.9 | | 180.0 | | 403.8 | | 44.9 | | 71.2 | | 292.1 | |
| 2012 | 208.3 | | 151.7 | | 185.8 | | 418.9 | | 46.1 | | 71.6 | | 305.3 | |
| 2013 | 214.6 | | 157.8 | | 191.8 | | 434.6 | | 47.4 | | 71.9 | | 319.0 | |
| 2014 | 221.0 | | 164.1 | | 197.9 | | 450.9 | | 48.7 | | 72.3 | | 333.4 | |
| 2015 | 227.6 | | 170.7 | | 204.2 | | 467.8 | | 50.0 | | 72.6 | | 348.4 | |

| 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] % Differen |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1994 | 309.3 | | 108.5 | | 49.0 | | 101.7 | | 91.3 | | | | 1291 | |
| 1995 | 307.2 | -0.7% | 109.0 | 0.5% | 50.8 | 3.7% | 106.2 | 4.4% | 93.8 | 2.7% | | | 1309 | 1.4% |
| 1996 | 294.0 | -4.3% | 106.2 | -2.6% | 49.8 | -2.0% | 109.6 | 3.2% | 95.8 | 2.1% | | | 1266 | -3.3% |
| 1997 | 320.0 | 8.8% | 117.7 | 10.8% | 51.0 | 2.4% | 111.6 | 1.8% | 97.2 | 1.5% | | | 1323 | 4.5% |
| 1998 | 332.9 | 4.0% | 125.8 | 6.9% | 53.8 | 5.5% | 115.2 | 3.2% | 101.5 | 4.4% | | | 1406 | 6.3% |
| 1999 | 352.9 | 6.0% | 128.9 | 2.5% | 58.2 | 8.2% | 118.8 | 3.1% | 102.0 | 0.5% | | | 1479 | 5.2% |
| 2000 | 340.0 | -3.7% | 125.5 | -2.7% | 53.7 | -7.7% | 114.7 | -3.5% | 100.2 | -1.8% | | | 1447 | -2.2% |
| 2001 | 374.0 | 10.0% | 137.7 | 9.7% | 62.0 | 15.5% | 135.0 | 17.7% | 111.0 | 10.8% | | | 1624 | 12.2% |
| 2002 | 391.7 | 4.7% | 140.6 | 2.1% | 67.4 | 8.7% | 142.8 | 5.8% | 118.6 | 6.8% | | | 1689 | 4.0% |
| 2003 | 381.1 | -2.7% | 146.5 | 4.2% | 67.3 | -0.1% | 145.9 | 2.2% | 118.8 | 0.2% | | | 1677 | -0.7% |
| 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% |
| 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% |
| 2006 | 408.1 | -0.9% | 168.0 | 4.1% | 72.7 | 2.5% | 170.55 | 4.7% | 134.0 | 3.0% | 33.9 | 5.0% | 1918.3 | 3.9% |
| 2007 | 411.4 | 0.8% | 161.2 | -4.1% | 75.2 | 3.5% | 155.72 | -8.7% | 125.3 | -6.5% | 29.5 | -12.9% | 1812.9 | -5.5% |
| 2008 | 409.2 | -0.5% | 165.8 | 2.9% | 69.6 | -7.4% | 145.78 | -6.4% | 117.4 | -6.3% | 30.5 | 3.3% | 1811.8 | -0.1% |
| 2009 | 374.8 | -8.4% | 155.5 | -6.2% | 68.7 | -1.3% | 147.14 | 0.9% | 122.9 | 4.7% | 28.9 | -5.3% | 1734.8 | -4.3% |
| Compounded Growth Rate | | 2.64% | | 2.83% | | 3.79% | | 4.83% | | 3.63% | | 7.98% | | 4.21% |
| Projected Growth Rate | | 2.50% | | 3.00% | | 3.50% | | 4.00% | | 3.50% | | 3.00% | | 3.40% |
| 2010 | 422.1 | | 173.1 | | 77.8 | | 180.5 | | 142.0 | | 34.9 | | 1983.5 | |
| 2011 | 432.6 | | 178.3 | | 80.6 | | 185.8 | | 144.5 | | 36.0 | | 2051.0 | |
| 2012 | 443.5 | | 183.6 | | 83.4 | | 191.9 | | 147.6 | | 37.1 | | 2120.7 | |
| 2013 | 454.6 | | 189.1 | | 86.3 | | 194.4 | | 150.3 | | 38.2 | | 2192.8 | |
| 2014 | 465.9 | | 194.8 | | 89.3 | | 201.7 | | 152.9 | | 39.3 | | 2267.4 | |
| 2015 | 477.6 | | 200.6 | | 92.4 | | 206.7 | | 155.9 | | 40.5 | | 2344.4 | |

# XVI. Appendix D – PSNH Supply Resources Used to Serve Energy Service Requirement

## Exhibit D-1: PSNH Energy Resources Used to Serve Total Default Energy Service Requirement

| | MWh | | | | | |
|---|---|---|---|---|---|---|
| **Name** | **2011** | **2012** | **2013** | **2014** | **2015** | **Expiration** |
| Merrimack Unit 1 | 841,454 | 901,238 | 841,454 | 772,448 | 898,776 | |
| Merrimack Unit 2 | 2,341,488 | 2,462,682 | 1,933,367 | 2,256,856 | 2,270,031 | |
| Schiller Unit 4 | 296,901 | 324,657 | 315,528 | 315,528 | 323,770 | |
| Schiller Unit 5 | 288,298 | 305,917 | 305,042 | 305,042 | 305,626 | |
| Schiller Unit 6 | 325,481 | 307,169 | 333,979 | 306,246 | 327,299 | |
| Newington | 105,120 | 105,120 | 105,120 | 105,120 | 105,120 | |
| Merrimack CT 1 | 0 | 0 | 0 | 0 | 0 | |
| Merrimack CT 2 | 0 | 0 | 0 | 0 | 0 | |
| Schiller CT | 0 | 0 | 0 | 0 | 0 | |
| Lost Nation | 0 | 0 | 0 | 0 | 0 | |
| White Lake | 0 | 0 | 0 | 0 | 0 | |
| Amoskeag | 89,943 | 90,189 | 89,943 | 89,943 | 89,943 | |
| Ayers Island | 44,098 | 44,219 | 44,098 | 44,098 | 44,098 | |
| Caanan | 7,456 | 7,476 | 7,456 | 7,456 | 7,456 | |
| Eastman Falls | 24,745 | 24,813 | 24,745 | 24,745 | 24,745 | |
| Garvins Falls/Hooksett | 51,411 | 51,552 | 51,411 | 51,411 | 51,411 | |
| Gorham | 12,044 | 12,077 | 12,044 | 12,044 | 12,044 | |
| Jackman | 9,404 | 9,430 | 9,404 | 9,404 | 9,404 | |
| Smith | 103,848 | 104,133 | 103,848 | 103,848 | 103,848 | |
| Vermont Yankee | 168,403 | 40,116 | 0 | 0 | 0 | |
| Wyman 4 | 0 | 0 | 0 | 0 | 0 | |
| West Hopkinton Hydro | 2,987 | 2,738 | 0 | 0 | 0 | Oct-2012 |
| Garland Mill | 33 | 28 | 0 | 0 | 0 | Oct-2012 |
| Rollinsford Hydro | 6,258 | 6,258 | 4,693 | 0 | 0 | Sep-2013 |
| Penacook Lower Falls | 24,194 | 24,194 | 18,146 | 0 | 0 | Sep-2013 |
| Great Falls Lower | 4,302 | 4,302 | 4,302 | 1,434 | 0 | Apr-2014 |
| Newfound Hydro | 6,618 | 6,618 | 6,618 | 4,412 | 0 | Aug-2014 |
| Nashua Hydro | 4,988 | 4,988 | 4,988 | 4,988 | 0 | Dec-2014 |
| Steels Pond Hydro | 1,193 | 1,193 | 1,193 | 1,193 | 0 | Dec-2014 |
| Watson Dam | 1,128 | 1,128 | 1,128 | 1,128 | 1,128 | Jan-2015 |
| Sugar River Hydro | 563 | 563 | 563 | 563 | 563 | Dec-2015 |
| Four Hills Landfill | 1,644 | 1,644 | 1,644 | 1,644 | 1,644 | Mar-2016 |
| Peterborough Lower Hydro | 625 | 625 | 625 | 625 | 625 | Dec-2017 |
| Peterborough Upper Hydro | 564 | 564 | 564 | 564 | 564 | Dec-2017 |
| WES Concord MSW | 102,000 | 102,000 | 102,000 | 102,000 | 102,000 | Dec-2018 |
| Penacook Upper Falls | 17,551 | 17,551 | 17,551 | 17,551 | 17,551 | Dec-2021 |
| Briar Hydro | 25,007 | 25,007 | 25,007 | 25,007 | 25,007 | Dec-2022 |
| Errol Dam | 17,474 | 17,474 | 17,474 | 17,474 | 17,474 | Dec-2023 |
| Lempster Wind | 59,638 | 59,854 | 59,638 | 59,638 | 59,638 | Sep-2027 |
| Laidlaw | 0 | 0 | 272,400 | 474,062 | 474,062 | Dec-2030 |
| BioEnergy Buyout | 75,840 | 75,840 | 75,840 | 75,840 | 37,920 | |
| | | | | | | |
| Total Energy Resources | 5,062,700 | 5,143,355 | 4,791,811 | 5,192,311 | 5,311,746 | |

## Exhibit D-2: PSNH Energy Resources Used to Serve On Peak Default Energy Service Requirement

| | MWh | | | | | |
|---|---|---|---|---|---|---|
| **Name** | **2011** | **2012** | **2013** | **2014** | **2015** | **Expiration** |
| Merrimack Unit 1 | 393,447 | 420,250 | 391,910 | 359,770 | 420,250 | |
| Merrimack Unit 2 | 1,094,833 | 1,148,355 | 900,472 | 1,051,139 | 1,061,421 | |
| Schiller Unit 4 | 138,825 | 151,388 | 146,958 | 146,958 | 151,388 | |
| Schiller Unit 5 | 134,803 | 142,650 | 142,074 | 142,074 | 142,905 | |
| Schiller Unit 6 | 152,188 | 143,234 | 155,552 | 142,635 | 153,038 | |
| Newington | 105,120 | 105,120 | 105,120 | 105,120 | 105,120 | |
| Merrimack CT 1 | 0 | 0 | 0 | 0 | 0 | |
| Merrimack CT 2 | 0 | 0 | 0 | 0 | 0 | |
| Schiller CT | 0 | 0 | 0 | 0 | 0 | |
| Lost Nation | 0 | 0 | 0 | 0 | 0 | |
| White Lake | 0 | 0 | 0 | 0 | 0 | |
| Amoskeag | 42,056 | 42,056 | 41,891 | 41,891 | 42,056 | |
| Ayers Island | 20,619 | 20,619 | 20,539 | 20,539 | 20,619 | |
| Caanan | 3,486 | 3,486 | 3,473 | 3,473 | 3,486 | |
| Eastman Falls | 11,570 | 11,570 | 11,525 | 11,525 | 11,570 | |
| Garvins Falls/Hooksett | 24,039 | 24,039 | 23,945 | 23,945 | 24,039 | |
| Gorham | 5,632 | 5,632 | 5,610 | 5,610 | 5,632 | |
| Jackman | 4,397 | 4,397 | 4,380 | 4,380 | 4,397 | |
| Smith | 48,557 | 48,557 | 48,368 | 48,368 | 48,557 | |
| Vermont Yankee | 78,742 | 19,103 | 0 | 0 | 0 | |
| Wyman 4 | 0 | 0 | 0 | 0 | 0 | |
| West Hopkinton Hydro | 1,397 | 1,277 | 0 | 0 | 0 | Oct-2012 |
| Garland Mill | 15 | 13 | 0 | 0 | 0 | Oct-2012 |
| Rollinsford Hydro | 2,926 | 2,918 | 2,186 | 0 | 0 | Sep-2013 |
| Penacook Lower Falls | 11,313 | 11,282 | 8,451 | 0 | 0 | Sep-2013 |
| Great Falls Lower | 2,011 | 2,006 | 2,003 | 668 | 0 | Apr-2014 |
| Newfound Hydro | 3,095 | 3,086 | 3,082 | 2,055 | 0 | Aug-2014 |
| Nashua Hydro | 2,332 | 2,326 | 2,323 | 2,323 | 0 | Dec-2014 |
| Steels Pond Hydro | 558 | 556 | 555 | 555 | 0 | Dec-2014 |
| Watson Dam | 527 | 526 | 525 | 525 | 527 | Jan-2015 |
| Sugar River Hydro | 263 | 262 | 262 | 262 | 263 | Dec-2015 |
| Four Hills Landfill | 769 | 767 | 766 | 766 | 769 | Mar-2016 |
| Peterborough Lower Hydro | 292 | 292 | 291 | 291 | 292 | Dec-2017 |
| Peterborough Upper Hydro | 264 | 263 | 263 | 263 | 264 | Dec-2017 |
| WES Concord MSW | 47,693 | 47,563 | 47,507 | 47,507 | 47,693 | Dec-2018 |
| Penacook Upper Falls | 8,206 | 8,184 | 8,174 | 8,174 | 8,206 | Dec-2021 |
| Briar Hydro | 11,693 | 11,661 | 11,647 | 11,647 | 11,693 | Dec-2022 |
| Errol Dam | 8,170 | 8,148 | 8,138 | 8,138 | 8,170 | Dec-2023 |
| Lempster Wind | 27,885 | 27,910 | 27,776 | 27,776 | 27,885 | Sep-2027 |
| Laidlaw | 0 | 0 | 126,871 | 220,796 | 221,662 | Dec-2030 |
| BioEnergy Buyout | 35,461 | 35,364 | 35,323 | 35,323 | 17,731 | |
| | | | | | | |
| Total Energy Resources | 2,423,185 | 2,454,857 | 2,287,962 | 2,474,497 | 2,539,634 | |

## Exhibit D-3: PSNH Energy Resources Used to Serve Off Peak Default Energy Service Requirement

| | MWh | | | | | |
|---|---|---|---|---|---|---|
| **Name** | **2011** | **2012** | **2013** | **2014** | **2015** | **Expiration** |
| Merrimack Unit 1 | 448,007 | 480,989 | 449,544 | 412,678 | 478,526 | |
| Merrimack Unit 2 | 1,246,655 | 1,314,328 | 1,032,895 | 1,205,718 | 1,208,610 | |
| Schiller Unit 4 | 158,076 | 173,268 | 168,570 | 168,570 | 172,381 | |
| Schiller Unit 5 | 153,496 | 163,267 | 162,968 | 162,968 | 162,721 | |
| Schiller Unit 6 | 173,293 | 163,936 | 178,427 | 163,611 | 174,261 | |
| Newington | 0 | 0 | 0 | 0 | 0 | |
| Merrimack CT 1 | 0 | 0 | 0 | 0 | 0 | |
| Merrimack CT 2 | 0 | 0 | 0 | 0 | 0 | |
| Schiller CT | 0 | 0 | 0 | 0 | 0 | |
| Lost Nation | 0 | 0 | 0 | 0 | 0 | |
| White Lake | 0 | 0 | 0 | 0 | 0 | |
| Amoskeag | 47,887 | 48,134 | 48,052 | 48,052 | 47,887 | |
| Ayers Island | 23,479 | 23,599 | 23,559 | 23,559 | 23,479 | |
| Caanan | 3,970 | 3,990 | 3,983 | 3,983 | 3,970 | |
| Eastman Falls | 13,175 | 13,243 | 13,220 | 13,220 | 13,175 | |
| Garvins Falls/Hooksett | 27,372 | 27,513 | 27,466 | 27,466 | 27,372 | |
| Gorham | 6,412 | 6,445 | 6,434 | 6,434 | 6,412 | |
| Jackman | 5,007 | 5,033 | 5,024 | 5,024 | 5,007 | |
| Smith | 55,291 | 55,575 | 55,480 | 55,480 | 55,291 | |
| Vermont Yankee | 89,661 | 21,013 | 0 | 0 | 0 | |
| Wyman 4 | 0 | 0 | 0 | 0 | 0 | |
| West Hopkinton Hydro | 1,590 | 1,461 | 0 | 0 | 0 | Oct-2012 |
| Garland Mill | 18 | 15 | 0 | 0 | 0 | Oct-2012 |
| Rollinsford Hydro | 3,332 | 3,340 | 2,507 | 0 | 0 | Sep-2013 |
| Penacook Lower Falls | 12,881 | 12,912 | 9,694 | 0 | 0 | Sep-2013 |
| Great Falls Lower | 2,290 | 2,296 | 2,298 | 766 | 0 | Apr-2014 |
| Newfound Hydro | 3,524 | 3,532 | 3,536 | 2,357 | 0 | Aug-2014 |
| Nashua Hydro | 2,656 | 2,662 | 2,665 | 2,665 | 0 | Dec-2014 |
| Steels Pond Hydro | 635 | 636 | 637 | 637 | 0 | Dec-2014 |
| Watson Dam | 601 | 602 | 603 | 603 | 601 | Jan-2015 |
| Sugar River Hydro | 300 | 300 | 301 | 301 | 300 | Dec-2015 |
| Four Hills Landfill | 875 | 877 | 878 | 878 | 875 | Mar-2016 |
| Peterborough Lower Hydro | 333 | 334 | 334 | 334 | 333 | Dec-2017 |
| Peterborough Upper Hydro | 301 | 301 | 302 | 302 | 301 | Dec-2017 |
| WES Concord MSW | 54,307 | 54,437 | 54,493 | 54,493 | 54,307 | Dec-2018 |
| Penacook Upper Falls | 9,344 | 9,367 | 9,376 | 9,376 | 9,344 | Dec-2021 |
| Briar Hydro | 13,314 | 13,346 | 13,360 | 13,360 | 13,314 | Dec-2022 |
| Errol Dam | 9,303 | 9,326 | 9,335 | 9,335 | 9,303 | Dec-2023 |
| Lempster Wind | 31,752 | 31,944 | 31,861 | 31,861 | 31,752 | Sep-2027 |
| Laidlaw | 0 | 0 | 145,529 | 253,266 | 252,400 | Dec-2030 |
| BioEnergy Buyout | 40,379 | 40,476 | 40,517 | 40,517 | 20,189 | |
| | | | | | | |
| Total Energy Resources | 2,639,515 | 2,688,497 | 2,503,848 | 2,717,814 | 2,772,112 | |

## Exhibit D-4: PSNH Energy Service Supplemental Energy Purchases and Spot Market Sales Under Varying Migration Levels

| | GWh | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2011** | | | **2012** | | | **2013** | | | **2014** | | | **2015** | | |
| | **Peak** | **Off** | **7x24** | **Peak** | **Off** | **7x24** | **Peak** | **Off** | **7x24** | **Peak** | **Off** | **7x24** | **Peak** | **Off** | **7x24** |
| Hydro | 160 | 183 | 343 | 160 | 184 | 344 | 160 | 183 | 343 | 160 | 183 | 343 | 160 | 183 | 343 |
| Coal | 1,779 | 2,026 | 3,805 | 1,863 | 2,133 | 3,996 | 1,595 | 1,829 | 3,424 | 1,701 | 1,951 | 3,651 | 1,786 | 2,034 | 3,820 |
| Wood | 135 | 153 | 288 | 143 | 163 | 306 | 142 | 163 | 305 | 142 | 163 | 305 | 143 | 163 | 306 |
| IC/Jets | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear | 79 | 90 | 168 | 19 | 21 | 40 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Newington | 105 | 0 | 105 | 105 | 0 | 105 | 105 | 0 | 105 | 105 | 0 | 105 | 105 | 0 | 105 |
| Contracted Power (LT IPPs) | 165 | 188 | 353 | 164 | 188 | 353 | 286 | 328 | 614 | 367 | 421 | 788 | 345 | 393 | 738 |
| Expected Generation | 2,423 | 2,640 | 5,063 | 2,455 | 2,688 | 5,143 | 2,288 | 2,504 | 4,792 | 2,474 | 2,718 | 5,192 | 2,540 | 2,772 | 5,312 |
| | | | | | | | | | | | | | | | |
| **Migration Level: 40%** | | | | | | | | | | | | | | | |
| Supplemental Energy Purchases | 252 | (370) | (118) | 251 | (393) | (142) | 432 | (206) | 226 | 292 | (408) | (116) | 277 | (468) | (191) |
| Total Requirement | 2,675 | 2,270 | 4,945 | 2,706 | 2,296 | 5,001 | 2,720 | 2,298 | 5,018 | 2,767 | 2,310 | 5,076 | 2,816 | 2,304 | 5,120 |
| | | | | | | | | | | | | | | | |
| **Migration Level: 31%** | | | | | | | | | | | | | | | |
| Supplemental ES Purchases | 653 | (29) | 624 | 657 | (49) | 608 | 840 | 139 | 979 | 707 | (62) | 646 | 699 | (122) | 577 |
| Total Requirement | 3,076 | 2,610 | 5,686 | 3,112 | 2,640 | 5,752 | 3,128 | 2,643 | 5,771 | 3,182 | 2,656 | 5,838 | 3,239 | 2,650 | 5,888 |
| | | | | | | | | | | | | | | | |
| **Migration Level: 25%** | | | | | | | | | | | | | | | |
| Supplemental Energy Purchases | 921 | 198 | 1,118 | 927 | 181 | 1,108 | 1,112 | 369 | 1,481 | 984 | 169 | 1,153 | 981 | 108 | 1,089 |
| Total Requirement | 3,344 | 2,837 | 6,181 | 3,382 | 2,870 | 6,252 | 3,400 | 2,873 | 6,272 | 3,458 | 2,887 | 6,346 | 3,520 | 2,880 | 6,401 |
| | | | | | | | | | | | | | | | |
| **Migration Level: 0%** | | | | | | | | | | | | | | | |
| Supplemental Energy Purchases | 2,035 | 1,143 | 3,179 | 2,055 | 1,138 | 3,192 | 2,245 | 1,327 | 3,572 | 2,137 | 1,132 | 3,268 | 2,154 | 1,068 | 3,222 |
| Total Requirement | 4,459 | 3,783 | 8,241 | 4,510 | 3,826 | 8,336 | 4,533 | 3,830 | 8,363 | 4,611 | 3,850 | 8,461 | 4,694 | 3,840 | 8,534 |

As of the preparation of this plan migration stood at about 31%

## Exhibit D-5: On-Peak Supply Resources Used to Serve 2009 Default Energy Service Requirement

| | | | Portion of Energy Service Requirement Served by... | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Energy Requirement MWh | PSNH Resource Subtotal | IPP | Buyout Contracts | Vermont Yankee | Hydro | Merrimack and Schiller | Newington and Wyman | Bilateral Purchase | ISO-NE Spot Purchases | Combustion Turbines | Energy Requirement MWh |
| Jan | 353,075 | 77% | 6% | 0% | 2% | 4% | 50% | 15% | 19% | 4% | 0.00% | 6% |
| Feb | 295,226 | 65% | 6% | 1% | 2% | 4% | 48% | 4% | 28% | 7% | 0.00% | 6% |
| Mar | 303,286 | 79% | 9% | 1% | 2% | 6% | 60% | 0% | 20% | 1% | 0.00% | 9% |
| Apr | 290,318 | 74% | 9% | 1% | 2% | 7% | 54% | 0% | 25% | 1% | 0.00% | 9% |
| May | 257,824 | 69% | 7% | 1% | 3% | 7% | 52% | 0% | 26% | 5% | 0.00% | 7% |
| Jun | 291,889 | 72% | 7% | 1% | 2% | 6% | 55% | 1% | 28% | 0% | 0.00% | 7% |
| Jul | 327,057 | 68% | 7% | 1% | 2% | 6% | 48% | 2% | 29% | 3% | 0.00% | 7% |
| Aug | 317,525 | 36% | 5% | 1% | 2% | 5% | 20% | 3% | 54% | 10% | 0.07% | 5% |
| Sep | 260,609 | 34% | 6% | 1% | 3% | 3% | 21% | 0% | 66% | 0% | 0.00% | 6% |
| Oct | 262,830 | 42% | 7% | 1% | 3% | 5% | 24% | 2% | 57% | 2% | 0.03% | 7% |
| Nov | 240,824 | 59% | 9% | 1% | 3% | 7% | 26% | 14% | 40% | 1% | 0.00% | 9% |
| Dec | 308,955 | 74% | 9% | 1% | 2% | 6% | 52% | 3% | 23% | 3% | 0.00% | 9% |
| Totals | 3,509,419 | 63% | 7% | 1% | 2% | 5% | 43% | 4% | 34% | 3% | 0.01% | 7% |

## Exhibit D-6: Off-Peak Supply Resources Used to Serve 2009 Default Energy Service Requirement

| | | | Portion of Energy Service Requirement Served by... | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Energy Requirement MWh | PSNH Resource Subtotal | IPP | Buyout Contracts | Vermont Yankee | Hydro | Merrimack and Schiller | Newington and Wyman | Bilateral Purchase | ISO-NE Spot Purchases | Combustion Turbines | Energy Requirement MWh |
| Jan | 348,510 | 88% | 7% | 1% | 2% | 5% | 62% | 10% | 10% | 2% | 0.00% | 348,510 |
| Feb | 285,807 | 74% | 7% | 1% | 3% | 5% | 58% | 1% | 18% | 8% | 0.01% | 285,807 |
| Mar | 288,549 | 92% | 11% | 1% | 3% | 8% | 69% | 0% | 7% | 1% | 0.00% | 288,549 |
| Apr | 232,255 | 82% | 12% | 2% | 3% | 10% | 56% | 0% | 14% | 3% | 0.00% | 232,255 |
| May | 256,162 | 86% | 9% | 1% | 3% | 9% | 63% | 0% | 10% | 5% | 0.00% | 256,162 |
| Jun | 227,548 | 83% | 9% | 2% | 3% | 8% | 61% | 0% | 15% | 3% | 0.00% | 227,548 |
| Jul | 242,678 | 85% | 11% | 1% | 3% | 9% | 61% | 0% | 11% | 5% | 0.00% | 242,678 |
| Aug | 307,014 | 44% | 8% | 1% | 3% | 7% | 25% | 0% | 44% | 12% | 0.00% | 307,014 |
| Sep | 222,044 | 45% | 8% | 2% | 4% | 4% | 28% | 0% | 50% | 5% | 0.02% | 222,044 |
| Oct | 225,757 | 50% | 9% | 2% | 4% | 6% | 30% | 0% | 46% | 4% | 0.01% | 225,757 |
| Nov | 234,778 | 57% | 12% | 2% | 3% | 9% | 30% | 1% | 41% | 2% | 0.05% | 234,778 |
| Dec | 272,650 | 86% | 11% | 1% | 3% | 7% | 62% | 2% | 8% | 6% | 0.00% | 272,650 |
| Totals | 3,143,751 | 73% | 9% | 1% | 3% | 7% | 51% | 1% | 22% | 5% | 0.01% | 3,143,751 |

"Buyout Contracts" refers to IPP Replacement Purchases (Bio Energy).
"PSNH Resource Subtotal" is the sum of all columns except bilateral and Spot purchases.
Lempster PPA is included in "IPPs". Bethlehem & Tamworth PPAs are in "Bilateral Purchases".

# XVII. Appendix E – PSNH Capacity Position and Purchase Activity

## Exhibit E-1: Summary of 2009 Capacity Position and Residual Supported Capacity

| | Share of ISO-NE Requirement (MW) | PSNH Owned Assets (MW) | IPPs / Contracts (MW) | Vermont Yankee (MW) | Hydro Quebec Credits (MW) | Supported Through Settlement (MW) |
|---|---|---|---|---|---|---|
| Jan | 2,148 | 1129 | 118 | 20 | 0 | 882 |
| Feb | 2,124 | 1129 | 119 | 20 | 0 | 856 |
| Mar | 2,212 | 1130 | 128 | 20 | 129 | 804 |
| Apr | 2,159 | 1130 | 130 | 20 | 129 | 750 |
| May | 2,125 | 1129 | 127 | 20 | 129 | 720 |
| Jun | 1,893 | 1115 | 109 | 19 | 129 | 521 |
| Jul | 1,834 | 1112 | 94 | 19 | 129 | 481 |
| Aug | 1,790 | 1111 | 91 | 19 | 129 | 440 |
| Sep | 1,752 | 1110 | 90 | 19 | 129 | 404 |
| Oct | 1,888 | 1128 | 97 | 21 | 129 | 514 |
| Nov | 1,854 | 1130 | 113 | 21 | 129 | 461 |
| Dec | 1,779 | 1129 | 117 | 21 | 0 | 511 |
| Total | 23,557 | 13,483 | 1,334 | 235 | 1,159 | 7,346 |
| % of Total | | 57% | 6% | 1% | 5% | 31% |

# XVIII. Appendix F – Monthly Capacity Balance

## Exhibit F-1: PSNH Monthly Energy Service Capacity Balance 2011 through 2015 under Varying Migration Levels

| **2011** | Case | Migration Level (%) | Jan-2011 (MW) | Feb-2011 (MW) | Mar-2011 (MW) | Apr-2011 (MW) | May-2011 (MW) | Jun-2011 (MW) | Jul-2011 (MW) | Aug-2011 (MW) | Sep-2011 (MW) | Oct-2011 (MW) | Nov-2011 (MW) | Dec-2011 (MW) | Total (MW-mo) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PSNH controlled resources | | | 1,135 | 1,135 | 1,285 | 1,285 | 1,285 | 1,115 | 1,115 | 1,115 | 1,115 | 1,125 | 1,125 | 1,125 | 1,163 |
| | | | | | | | | | | | | | | | |
| ISO-NE ICR | High | | 32,477 | 32,477 | 33,877 | 33,877 | 33,877 | 33,689 | 33,689 | 33,689 | 33,689 | 33,689 | 33,689 | 33,689 | 33,534 |
| | Reference | | 32,305 | 32,305 | 33,705 | 33,705 | 33,705 | 33,439 | 33,439 | 33,439 | 33,439 | 33,439 | 33,439 | 33,439 | 33,317 |
| | Low | | 32,144 | 32,144 | 33,544 | 33,544 | 33,544 | 33,200 | 33,200 | 33,200 | 33,200 | 33,200 | 33,200 | 33,200 | 33,110 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 40 | 1,266 | 1,266 | 1,321 | 1,321 | 1,321 | 1,313 | 1,313 | 1,313 | 1,313 | 1,313 | 1,313 | 1,313 | 1,307 |
| | Reference | 40 | 1,259 | 1,259 | 1,313 | 1,313 | 1,313 | 1,303 | 1,303 | 1,303 | 1,303 | 1,303 | 1,303 | 1,303 | 1,298 |
| | Low | 40 | 1,253 | 1,253 | 1,307 | 1,307 | 1,307 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,290 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 31 | 1,456 | 1,456 | 1,519 | 1,519 | 1,519 | 1,510 | 1,510 | 1,510 | 1,510 | 1,510 | 1,510 | 1,510 | 1,503 |
| | Reference | 31 | 1,448 | 1,448 | 1,510 | 1,510 | 1,510 | 1,499 | 1,499 | 1,499 | 1,499 | 1,499 | 1,499 | 1,499 | 1,493 |
| | Low | 31 | 1,441 | 1,441 | 1,504 | 1,504 | 1,504 | 1,488 | 1,488 | 1,488 | 1,488 | 1,488 | 1,488 | 1,488 | 1,484 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 25 | 1,583 | 1,583 | 1,651 | 1,651 | 1,651 | 1,641 | 1,641 | 1,641 | 1,641 | 1,641 | 1,641 | 1,641 | 1,634 |
| | Reference | 25 | 1,574 | 1,574 | 1,642 | 1,642 | 1,642 | 1,629 | 1,629 | 1,629 | 1,629 | 1,629 | 1,629 | 1,629 | 1,623 |
| | Low | 25 | 1,566 | 1,566 | 1,634 | 1,634 | 1,634 | 1,618 | 1,618 | 1,618 | 1,618 | 1,618 | 1,618 | 1,618 | 1,613 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 0 | 2,110 | 2,110 | 2,201 | 2,201 | 2,201 | 2,188 | 2,188 | 2,188 | 2,188 | 2,188 | 2,188 | 2,188 | 2,178 |
| | Reference | 0 | 2,098 | 2,098 | 2,189 | 2,189 | 2,189 | 2,172 | 2,172 | 2,172 | 2,172 | 2,172 | 2,172 | 2,172 | 2,164 |
| | Low | 0 | 2,088 | 2,088 | 2,179 | 2,179 | 2,179 | 2,157 | 2,157 | 2,157 | 2,157 | 2,157 | 2,157 | 2,157 | 2,151 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 40 | 131 | 131 | 36 | 36 | 36 | 198 | 198 | 198 | 198 | 188 | 188 | 188 | 144 |
| | Reference | 40 | 124 | 124 | 28 | 28 | 28 | 188 | 188 | 188 | 188 | 178 | 178 | 178 | 135 |
| | Low | 40 | 118 | 118 | 22 | 22 | 22 | 179 | 179 | 179 | 179 | 169 | 169 | 169 | 127 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 31 | 321 | 321 | 234 | 234 | 234 | 395 | 395 | 395 | 395 | 385 | 385 | 385 | 340 |
| | Reference | 31 | 313 | 313 | 225 | 225 | 225 | 384 | 384 | 384 | 384 | 374 | 374 | 374 | 330 |
| | Low | 31 | 306 | 306 | 219 | 219 | 219 | 373 | 373 | 373 | 373 | 363 | 363 | 363 | 321 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 25 | 448 | 448 | 366 | 366 | 366 | 526 | 526 | 526 | 526 | 516 | 516 | 516 | 471 |
| | Reference | 25 | 439 | 439 | 357 | 357 | 357 | 514 | 514 | 514 | 514 | 504 | 504 | 504 | 460 |
| | Low | 25 | 431 | 431 | 349 | 349 | 349 | 503 | 503 | 503 | 503 | 493 | 493 | 493 | 450 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 0 | 975 | 975 | 916 | 916 | 916 | 1,073 | 1,073 | 1,073 | 1,073 | 1,063 | 1,063 | 1,063 | 1,015 |
| | Reference | 0 | 963 | 963 | 904 | 904 | 904 | 1,057 | 1,057 | 1,057 | 1,057 | 1,047 | 1,047 | 1,047 | 1,001 |
| | Low | 0 | 953 | 953 | 894 | 894 | 894 | 1,042 | 1,042 | 1,042 | 1,042 | 1,032 | 1,032 | 1,032 | 988 |

| **2012** | Case | Migration Level | Jan-2012 | Feb-2012 | Mar-2012 | Apr-2012 | May-2012 | Jun-2012 | Jul-2012 | Aug-2012 | Sep-2012 | Oct-2012 | Nov-2012 | Dec-2012 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (%) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW-mo) |
| PSNH controlled resources | | | 1,125 | 1,125 | 1,125 | 1,107 | 1,107 | 1,091 | 1,091 | 1,091 | 1,091 | 1,105 | 1,105 | 1,105 | 1,106 |
| | | | | | | | | | | | | | | | |
| ISO-NE ICR | High | | 33,689 | 33,689 | 33,689 | 33,689 | 33,689 | 33,215 | 33,215 | 33,215 | 33,215 | 33,215 | 33,215 | 33,215 | 33,413 |
| | Reference | | 33,439 | 33,439 | 33,439 | 33,439 | 33,439 | 32,879 | 32,879 | 32,879 | 32,879 | 32,879 | 32,879 | 32,879 | 33,112 |
| | Low | | 33,200 | 33,200 | 33,200 | 33,200 | 33,200 | 32,565 | 32,565 | 32,565 | 32,565 | 32,565 | 32,565 | 32,565 | 32,830 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 40 | 1,313 | 1,313 | 1,313 | 1,313 | 1,313 | 1,295 | 1,295 | 1,295 | 1,295 | 1,295 | 1,295 | 1,295 | 1,303 |
| | Reference | 40 | 1,303 | 1,303 | 1,303 | 1,303 | 1,303 | 1,282 | 1,282 | 1,282 | 1,282 | 1,282 | 1,282 | 1,282 | 1,291 |
| | Low | 40 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,269 | 1,269 | 1,269 | 1,269 | 1,269 | 1,269 | 1,269 | 1,279 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 31 | 1,510 | 1,510 | 1,510 | 1,510 | 1,510 | 1,489 | 1,489 | 1,489 | 1,489 | 1,489 | 1,489 | 1,489 | 1,498 |
| | Reference | 31 | 1,499 | 1,499 | 1,499 | 1,499 | 1,499 | 1,474 | 1,474 | 1,474 | 1,474 | 1,474 | 1,474 | 1,474 | 1,484 |
| | Low | 31 | 1,488 | 1,488 | 1,488 | 1,488 | 1,488 | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 | 1,471 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 25 | 1,641 | 1,641 | 1,641 | 1,641 | 1,641 | 1,619 | 1,619 | 1,619 | 1,619 | 1,619 | 1,619 | 1,619 | 1,628 |
| | Reference | 25 | 1,629 | 1,629 | 1,629 | 1,629 | 1,629 | 1,602 | 1,602 | 1,602 | 1,602 | 1,602 | 1,602 | 1,602 | 1,613 |
| | Low | 25 | 1,618 | 1,618 | 1,618 | 1,618 | 1,618 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,599 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 0 | 2,188 | 2,188 | 2,188 | 2,188 | 2,188 | 2,158 | 2,158 | 2,158 | 2,158 | 2,158 | 2,158 | 2,158 | 2,171 |
| | Reference | 0 | 2,172 | 2,172 | 2,172 | 2,172 | 2,172 | 2,136 | 2,136 | 2,136 | 2,136 | 2,136 | 2,136 | 2,136 | 2,151 |
| | Low | 0 | 2,157 | 2,157 | 2,157 | 2,157 | 2,157 | 2,115 | 2,115 | 2,115 | 2,115 | 2,115 | 2,115 | 2,115 | 2,133 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 40 | 188 | 188 | 188 | 206 | 206 | 204 | 204 | 204 | 204 | 190 | 190 | 190 | 197 |
| | Reference | 40 | 178 | 178 | 178 | 196 | 196 | 191 | 191 | 191 | 191 | 177 | 177 | 177 | 185 |
| | Low | 40 | 169 | 169 | 169 | 187 | 187 | 178 | 178 | 178 | 178 | 164 | 164 | 164 | 174 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 31 | 385 | 385 | 385 | 403 | 403 | 398 | 398 | 398 | 398 | 384 | 384 | 384 | 392 |
| | Reference | 31 | 374 | 374 | 374 | 392 | 392 | 383 | 383 | 383 | 383 | 369 | 369 | 369 | 379 |
| | Low | 31 | 363 | 363 | 363 | 381 | 381 | 368 | 368 | 368 | 368 | 354 | 354 | 354 | 365 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 25 | 516 | 516 | 516 | 534 | 534 | 528 | 528 | 528 | 528 | 514 | 514 | 514 | 523 |
| | Reference | 25 | 504 | 504 | 504 | 522 | 522 | 511 | 511 | 511 | 511 | 497 | 497 | 497 | 508 |
| | Low | 25 | 493 | 493 | 493 | 511 | 511 | 495 | 495 | 495 | 495 | 481 | 481 | 481 | 494 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 0 | 1,063 | 1,063 | 1,063 | 1,081 | 1,081 | 1,067 | 1,067 | 1,067 | 1,067 | 1,053 | 1,053 | 1,053 | 1,065 |
| | Reference | 0 | 1,047 | 1,047 | 1,047 | 1,065 | 1,065 | 1,045 | 1,045 | 1,045 | 1,045 | 1,031 | 1,031 | 1,031 | 1,045 |
| | Low | 0 | 1,032 | 1,032 | 1,032 | 1,050 | 1,050 | 1,024 | 1,024 | 1,024 | 1,024 | 1,010 | 1,010 | 1,010 | 1,027 |

| 2013 | Case | Migration Level | Jan-2013 | Feb-2013 | Mar-2013 | Apr-2013 | May-2013 | Jun-2013 | Jul-2013 | Aug-2013 | Sep-2013 | Oct-2013 | Nov-2013 | Dec-2013 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (%) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW-mo) |
| PSNH controlled resources | | | 1,105 | 1,105 | 1,105 | 1,105 | 1,105 | 1,083 | 1,083 | 1,083 | 1,083 | 1,092 | 1,092 | 1,092 | 1,094 |
| | | | | | | | | | | | | | | | |
| ISO-NE ICR | High | | 33,215 | 33,215 | 33,215 | 33,215 | 33,215 | 33,358 | 33,358 | 33,358 | 33,358 | 33,358 | 33,358 | 33,358 | 33,298 |
| | Reference | | 32,879 | 32,879 | 32,879 | 32,879 | 32,879 | 33,043 | 33,043 | 33,043 | 33,043 | 33,043 | 33,043 | 33,043 | 32,975 |
| | Low | | 32,565 | 32,565 | 32,565 | 32,565 | 32,565 | 32,739 | 32,739 | 32,739 | 32,739 | 32,739 | 32,739 | 32,739 | 32,667 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 40 | 1,295 | 1,295 | 1,295 | 1,295 | 1,295 | 1,300 | 1,300 | 1,300 | 1,300 | 1,300 | 1,300 | 1,300 | 1,298 |
| | Reference | 40 | 1,282 | 1,282 | 1,282 | 1,282 | 1,282 | 1,288 | 1,288 | 1,288 | 1,288 | 1,288 | 1,288 | 1,288 | 1,286 |
| | Low | 40 | 1,269 | 1,269 | 1,269 | 1,269 | 1,269 | 1,276 | 1,276 | 1,276 | 1,276 | 1,276 | 1,276 | 1,276 | 1,273 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 31 | 1,489 | 1,489 | 1,489 | 1,489 | 1,489 | 1,495 | 1,495 | 1,495 | 1,495 | 1,495 | 1,495 | 1,495 | 1,493 |
| | Reference | 31 | 1,474 | 1,474 | 1,474 | 1,474 | 1,474 | 1,481 | 1,481 | 1,481 | 1,481 | 1,481 | 1,481 | 1,481 | 1,478 |
| | Low | 31 | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,464 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 25 | 1,619 | 1,619 | 1,619 | 1,619 | 1,619 | 1,625 | 1,625 | 1,625 | 1,625 | 1,625 | 1,625 | 1,625 | 1,623 |
| | Reference | 25 | 1,602 | 1,602 | 1,602 | 1,602 | 1,602 | 1,610 | 1,610 | 1,610 | 1,610 | 1,610 | 1,610 | 1,610 | 1,607 |
| | Low | 25 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,595 | 1,595 | 1,595 | 1,595 | 1,595 | 1,595 | 1,595 | 1,591 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 0 | 2,158 | 2,158 | 2,158 | 2,158 | 2,158 | 2,167 | 2,167 | 2,167 | 2,167 | 2,167 | 2,167 | 2,167 | 2,163 |
| | Reference | 0 | 2,136 | 2,136 | 2,136 | 2,136 | 2,136 | 2,146 | 2,146 | 2,146 | 2,146 | 2,146 | 2,146 | 2,146 | 2,142 |
| | Low | 0 | 2,115 | 2,115 | 2,115 | 2,115 | 2,115 | 2,127 | 2,127 | 2,127 | 2,127 | 2,127 | 2,127 | 2,127 | 2,122 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 40 | 190 | 190 | 190 | 190 | 190 | 217 | 217 | 217 | 217 | 208 | 208 | 208 | 204 |
| | Reference | 40 | 177 | 177 | 177 | 177 | 177 | 205 | 205 | 205 | 205 | 196 | 196 | 196 | 191 |
| | Low | 40 | 164 | 164 | 164 | 164 | 164 | 193 | 193 | 193 | 193 | 184 | 184 | 184 | 179 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 31 | 384 | 384 | 384 | 384 | 384 | 412 | 412 | 412 | 412 | 403 | 403 | 403 | 398 |
| | Reference | 31 | 369 | 369 | 369 | 369 | 369 | 398 | 398 | 398 | 398 | 389 | 389 | 389 | 384 |
| | Low | 31 | 354 | 354 | 354 | 354 | 354 | 385 | 385 | 385 | 385 | 376 | 376 | 376 | 370 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 25 | 514 | 514 | 514 | 514 | 514 | 542 | 542 | 542 | 542 | 533 | 533 | 533 | 528 |
| | Reference | 25 | 497 | 497 | 497 | 497 | 497 | 527 | 527 | 527 | 527 | 518 | 518 | 518 | 512 |
| | Low | 25 | 481 | 481 | 481 | 481 | 481 | 512 | 512 | 512 | 512 | 503 | 503 | 503 | 497 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 0 | 1,053 | 1,053 | 1,053 | 1,053 | 1,053 | 1,084 | 1,084 | 1,084 | 1,084 | 1,075 | 1,075 | 1,075 | 1,069 |
| | Reference | 0 | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 1,063 | 1,063 | 1,063 | 1,063 | 1,054 | 1,054 | 1,054 | 1,047 |
| | Low | 0 | 1,010 | 1,010 | 1,010 | 1,010 | 1,010 | 1,044 | 1,044 | 1,044 | 1,044 | 1,035 | 1,035 | 1,035 | 1,028 |

| 2014 | Case | Migration Level | Jan-2014 | Feb-2014 | Mar-2014 | Apr-2014 | May-2014 | Jun-2014 | Jul-2014 | Aug-2014 | Sep-2014 | Oct-2014 | Nov-2014 | Dec-2014 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (%) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW-mo) |
| PSNH controlled resources | | | 1,092 | 1,092 | 1,092 | 1,092 | 1,092 | 1,133 | 1,133 | 1,133 | 1,133 | 1,145 | 1,137 | 1,137 | 1,118 |
| | | | | | | | | | | | | | | | |
| ISO-NE ICR | High | | 33,358 | 33,358 | 33,358 | 33,358 | 33,358 | 33,999 | 33,999 | 33,999 | 33,999 | 33,999 | 33,999 | 33,999 | 33,732 |
| | Reference | | 33,043 | 33,043 | 33,043 | 33,043 | 33,043 | 33,588 | 33,588 | 33,588 | 33,588 | 33,588 | 33,588 | 33,588 | 33,361 |
| | Low | | 32,739 | 32,739 | 32,739 | 32,739 | 32,739 | 33,188 | 33,188 | 33,188 | 33,188 | 33,188 | 33,188 | 33,188 | 33,001 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 40 | 1,300 | 1,300 | 1,300 | 1,300 | 1,300 | 1,325 | 1,325 | 1,325 | 1,325 | 1,325 | 1,325 | 1,325 | 1,315 |
| | Reference | 40 | 1,288 | 1,288 | 1,288 | 1,288 | 1,288 | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 | 1,300 |
| | Low | 40 | 1,276 | 1,276 | 1,276 | 1,276 | 1,276 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,287 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 31 | 1,495 | 1,495 | 1,495 | 1,495 | 1,495 | 1,524 | 1,524 | 1,524 | 1,524 | 1,524 | 1,524 | 1,524 | 1,512 |
| | Reference | 31 | 1,481 | 1,481 | 1,481 | 1,481 | 1,481 | 1,506 | 1,506 | 1,506 | 1,506 | 1,506 | 1,506 | 1,506 | 1,496 |
| | Low | 31 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,488 | 1,488 | 1,488 | 1,488 | 1,488 | 1,488 | 1,488 | 1,480 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 25 | 1,625 | 1,625 | 1,625 | 1,625 | 1,625 | 1,656 | 1,656 | 1,656 | 1,656 | 1,656 | 1,656 | 1,656 | 1,643 |
| | Reference | 25 | 1,610 | 1,610 | 1,610 | 1,610 | 1,610 | 1,637 | 1,637 | 1,637 | 1,637 | 1,637 | 1,637 | 1,637 | 1,626 |
| | Low | 25 | 1,595 | 1,595 | 1,595 | 1,595 | 1,595 | 1,617 | 1,617 | 1,617 | 1,617 | 1,617 | 1,617 | 1,617 | 1,608 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 0 | 2,167 | 2,167 | 2,167 | 2,167 | 2,167 | 2,208 | 2,208 | 2,208 | 2,208 | 2,208 | 2,208 | 2,208 | 2,191 |
| | Reference | 0 | 2,146 | 2,146 | 2,146 | 2,146 | 2,146 | 2,182 | 2,182 | 2,182 | 2,182 | 2,182 | 2,182 | 2,182 | 2,167 |
| | Low | 0 | 2,127 | 2,127 | 2,127 | 2,127 | 2,127 | 2,156 | 2,156 | 2,156 | 2,156 | 2,156 | 2,156 | 2,156 | 2,144 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 40 | 208 | 208 | 208 | 208 | 208 | 192 | 192 | 192 | 192 | 180 | 188 | 188 | 197 |
| | Reference | 40 | 196 | 196 | 196 | 196 | 196 | 176 | 176 | 176 | 176 | 164 | 172 | 172 | 183 |
| | Low | 40 | 184 | 184 | 184 | 184 | 184 | 161 | 161 | 161 | 161 | 149 | 157 | 157 | 169 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 31 | 403 | 403 | 403 | 403 | 403 | 391 | 391 | 391 | 391 | 379 | 387 | 387 | 394 |
| | Reference | 31 | 389 | 389 | 389 | 389 | 389 | 373 | 373 | 373 | 373 | 361 | 369 | 369 | 378 |
| | Low | 31 | 376 | 376 | 376 | 376 | 376 | 355 | 355 | 355 | 355 | 343 | 351 | 351 | 362 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 25 | 533 | 533 | 533 | 533 | 533 | 523 | 523 | 523 | 523 | 511 | 519 | 519 | 526 |
| | Reference | 25 | 518 | 518 | 518 | 518 | 518 | 504 | 504 | 504 | 504 | 492 | 500 | 500 | 508 |
| | Low | 25 | 503 | 503 | 503 | 503 | 503 | 484 | 484 | 484 | 484 | 472 | 480 | 480 | 490 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 0 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,063 | 1,071 | 1,071 | 1,073 |
| | Reference | 0 | 1,054 | 1,054 | 1,054 | 1,054 | 1,054 | 1,049 | 1,049 | 1,049 | 1,049 | 1,037 | 1,045 | 1,045 | 1,049 |
| | Low | 0 | 1,035 | 1,035 | 1,035 | 1,035 | 1,035 | 1,023 | 1,023 | 1,023 | 1,023 | 1,011 | 1,019 | 1,019 | 1,026 |

| 2015 | Case | Migration Level | Jan-2015 | Feb-2015 | Mar-2015 | Apr-2015 | May-2015 | Jun-2015 | Jul-2015 | Aug-2015 | Sep-2015 | Oct-2015 | Nov-2015 | Dec-2015 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (%) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW-mo) |
| PSNH controlled resources | | | 1,136 | 1,136 | 1,136 | 1,136 | 1,136 | 1,129 | 1,129 | 1,129 | 1,129 | 1,136 | 1,136 | 1,136 | 1,134 |
| | | | | | | | | | | | | | | | |
| ISO-NE ICR | High | | 33,999 | 33,999 | 33,999 | 33,999 | 33,999 | 35,100 | 35,100 | 35,100 | 35,100 | 35,100 | 35,100 | 35,100 | 34,641 |
| | Reference | | 33,588 | 33,588 | 33,588 | 33,588 | 33,588 | 34,094 | 34,094 | 34,094 | 34,094 | 34,094 | 34,094 | 34,094 | 33,883 |
| | Low | | 33,188 | 33,188 | 33,188 | 33,188 | 33,188 | 34,077 | 34,077 | 34,077 | 34,077 | 34,077 | 34,077 | 34,077 | 33,707 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 40 | 1,325 | 1,325 | 1,325 | 1,325 | 1,325 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,350 |
| | Reference | 40 | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 | 1,329 | 1,329 | 1,329 | 1,329 | 1,329 | 1,329 | 1,329 | 1,321 |
| | Low | 40 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,328 | 1,328 | 1,328 | 1,328 | 1,328 | 1,328 | 1,328 | 1,314 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 31 | 1,524 | 1,524 | 1,524 | 1,524 | 1,524 | 1,573 | 1,573 | 1,573 | 1,573 | 1,573 | 1,573 | 1,573 | 1,553 |
| | Reference | 31 | 1,506 | 1,506 | 1,506 | 1,506 | 1,506 | 1,528 | 1,528 | 1,528 | 1,528 | 1,528 | 1,528 | 1,528 | 1,519 |
| | Low | 31 | 1,488 | 1,488 | 1,488 | 1,488 | 1,488 | 1,528 | 1,528 | 1,528 | 1,528 | 1,528 | 1,528 | 1,528 | 1,511 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 25 | 1,656 | 1,656 | 1,656 | 1,656 | 1,656 | 1,710 | 1,710 | 1,710 | 1,710 | 1,710 | 1,710 | 1,710 | 1,688 |
| | Reference | 25 | 1,637 | 1,637 | 1,637 | 1,637 | 1,637 | 1,661 | 1,661 | 1,661 | 1,661 | 1,661 | 1,661 | 1,661 | 1,651 |
| | Low | 25 | 1,617 | 1,617 | 1,617 | 1,617 | 1,617 | 1,661 | 1,661 | 1,661 | 1,661 | 1,661 | 1,661 | 1,661 | 1,643 |
| | | | | | | | | | | | | | | | |
| ES Capacity Share | High | 0 | 2,208 | 2,208 | 2,208 | 2,208 | 2,208 | 2,280 | 2,280 | 2,280 | 2,280 | 2,280 | 2,280 | 2,280 | 2,250 |
| | Reference | 0 | 2,182 | 2,182 | 2,182 | 2,182 | 2,182 | 2,215 | 2,215 | 2,215 | 2,215 | 2,215 | 2,215 | 2,215 | 2,201 |
| | Low | 0 | 2,156 | 2,156 | 2,156 | 2,156 | 2,156 | 2,214 | 2,214 | 2,214 | 2,214 | 2,214 | 2,214 | 2,214 | 2,190 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 40 | 189 | 189 | 189 | 189 | 189 | 239 | 239 | 239 | 239 | 232 | 232 | 232 | 216 |
| | Reference | 40 | 173 | 173 | 173 | 173 | 173 | 200 | 200 | 200 | 200 | 193 | 193 | 193 | 187 |
| | Low | 40 | 158 | 158 | 158 | 158 | 158 | 199 | 199 | 199 | 199 | 192 | 192 | 192 | 180 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 31 | 388 | 388 | 388 | 388 | 388 | 444 | 444 | 444 | 444 | 437 | 437 | 437 | 419 |
| | Reference | 31 | 370 | 370 | 370 | 370 | 370 | 399 | 399 | 399 | 399 | 392 | 392 | 392 | 385 |
| | Low | 31 | 352 | 352 | 352 | 352 | 352 | 399 | 399 | 399 | 399 | 392 | 392 | 392 | 378 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 25 | 520 | 520 | 520 | 520 | 520 | 581 | 581 | 581 | 581 | 574 | 574 | 574 | 554 |
| | Reference | 25 | 501 | 501 | 501 | 501 | 501 | 532 | 532 | 532 | 532 | 525 | 525 | 525 | 517 |
| | Low | 25 | 481 | 481 | 481 | 481 | 481 | 532 | 532 | 532 | 532 | 525 | 525 | 525 | 509 |
| | | | | | | | | | | | | | | | |
| Net Capacity Obligation | High | 0 | 1,072 | 1,072 | 1,072 | 1,072 | 1,072 | 1,151 | 1,151 | 1,151 | 1,151 | 1,144 | 1,144 | 1,144 | 1,116 |
| | Reference | 0 | 1,046 | 1,046 | 1,046 | 1,046 | 1,046 | 1,086 | 1,086 | 1,086 | 1,086 | 1,079 | 1,079 | 1,079 | 1,068 |
| | Low | 0 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,085 | 1,085 | 1,085 | 1,085 | 1,078 | 1,078 | 1,078 | 1,056 |

Notes:

- ICR for January 2011 through May 2014 are amounts purchased in respective forward capacity auctions adjusted monthly for HQ ICCs. ICR for June 2014 through December 2015 is from ICR forecast presentation at the April 27, 2010 Planning Advisory Committee meeting adjusted monthly for HQ ICCs. ICR values are not adjusted for intermittent resources winter obligations greater than summer obligations.
- PSNH controlled values are capacity supply obligations from FCA 1, 2, 3, and 4 with FCA 4 results held for subsequent years, includes proration and winter IPR MWs.
- ES share with no migration is peak load share at time of 2009 annual peak

## XIX. Appendix G – Newington Station Continuing Unit Operation Study

Attached is PSNH's Continuing Unit Operation Study for Newington Station. Commission Order No. 25,061 required PSNH to file a continuing unit operation study for Newington Station in its 2010 Least Cost Integrated Resource Plan filing. The study is submitted as Appendix G.

# Appendix G:

# Newington Station
# Continuing Unit Operations Study

# Levitan & Associates, Inc.

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

## Table of Contents

## Glossary of Terms

**2FO** – (#2) Distillate fuel oil
**ADIT** – Accelerated Depreciation Income Tax
**AGC** – Automatic generation control
**APR** – Alternative Price Rule
**BART** – Best Available Retrofit Technology
**CAIR** – Clean Air Interstate Rule
**CapEx** – Capital expenditure
**CC** – Combined cycle
**CELT** – Capacity, Energy, Loads and Transmission forecast
**$CO_2$** – Carbon dioxide
**CONE** – Cost of new entry
**CUO** – Continuing Unit Operation
**DA** – Day ahead
**DAM** – Day-ahead market
**DCF** – Discounted cash flow
**DR** – Demand Resources
**Dth** – Dekatherm
**EOY** – End of year
**EPA** – Environmental Protection Agency
**ES** – Energy Service
**ESP** – Electrostatic precipitator
**FCA** – Forward Capacity Auction
**FCM** – Forward Capacity Market
**FERC** – Federal Energy Regulatory Commission
**GHG** – Greenhouse gases
**GT** – Gas turbine
**ICR** – Installed Capacity Requirement
**IMM** – Internal Market Monitor
**IPP** – Independent power producer
**ISO-NE** – Independent System Operator New England
**IT** – Interruptible transportation
**kV** – Kilovolt
**LAI** – Levitan & Associates, Inc.
**LCIRP** – Least Cost Integrated Resource Plan
**LP turbine** – Low pressure turbine
**LT** – Long term
**MassHub** – Massachusetts Hub
**M&N** – M&N Operating Company, LLC
**M&S** – Materials and services
**MMBtu** – Million British thermal units
**MW** – Megawatt
**MWh** – Megawatt hour
**NHDES** – New Hampshire Department of Environmental Services
**NHPUC** – New Hampshire Public Utilities Commission
**$NO_x$** – Nitrogen oxides
**NPDES** – National Pollutant Discharge Elimination System
**NPV** – Net present value
**NYISO** – New York Independent System Operator
**O&M** – Operations and maintenance
**OOM** – Out of Market
**OSHA** – Occupational Safety and Health Administration
**PM** – Particulate matter
**PNGTS** – Portland Natural Gas Transmission System
**Psi** – Pounds per square inch
**PSNH** – Public Service Company of New Hampshire
**RFO** – (#6) Residual fuel oil
**ROV** – Real option valuation OR real option value
**RPS** – Renewable Portfolio Standard
**RSP** – Regional System Plan
**RT** – Real time
**RTM** – Real-time market
**SCR** – Selective catalytic reduction
**SIP** – State Implementation Plan
**SNCR** – Selective non-catalytic reduction
**$SO_2$** – Sulfur dioxide
**$SO_3$** – Sulfur trioxide
**SPS** – Special Protection System
**ST** – Short term
**TOU** – Time of use
**VAR** – Volt Ampere Reactive
**VER** – Variable energy resource
**WTI** – West Texas Intermediate
**YTD** – Year to date

# A. Overview

This study was performed by Levitan & Associates, Inc. (LAI) on behalf of Public Service Company of New Hampshire (PSNH). The study discusses the benefits and costs of continued operation of Newington Station (hereafter referred to as Newington Station, Newington, or the Station) and the value that Newington Station provides to customers, the State of New Hampshire, and ISO-New England (ISO-NE). Newington Station is located on a 53 acre site along the west bank of the Piscataqua River in Newington, New Hampshire. The Station is PSNH's largest single generating unit with a rated net capacity of 400.2 MW. The station began commercial operation in 1974 as a cycling unit to support the rapidly growing electric load in New Hampshire and New England. Initially designed to burn residual fuel oil (RFO) or bunker crude, the Station can burn natural gas as well as RFO. Throughout its history, Newington Station has been strategically varied in its operations and has served as a baseload, intermediate, and peaking unit. In recent years, the Station's capacity factor has decreased substantially. In response to Newington Station's lower recent capacity factor, PSNH was ordered by the New Hampshire Public Utilities Commission (NHPUC) to perform a Continuing Unit Operation (CUO) study of Newington Station in its 2010 Least Cost Integrated Resource Plan (LCIRP) filing.[1] Additionally, in response to data requests on the value that Newington Station provides to customers, PSNH has responded that Newington provides a hedge or insurance benefit to customers through ownership of a physical asset. In this study, LAI quantifies the hedge benefit that Newington Station provides to customers mainly through the use of a Real Option Valuation (ROV) analysis. The theory and application of ROV analysis are described in detail later in this study.

In conducting this analysis, LAI has assumed the continuation of cost-of-service regulation under NHPUC jurisdiction. In order to estimate the value realized by PSNH's customers ascribable to the Station, LAI considered the loss of value associated with the postulated retirement of Newington Station. If PSNH were to retire Newington Station, PSNH's customers would bear the cost of replacement energy, capacity, and ancillary services at market prices. There would also be other costs borne by PSNH's customers to take the place of the various risk management services associated with the scheduling and operation of Newington Station.

## A.1. Study Objectives

In order to determine the benefit of PSNH's continued ownership and operation of Newington Station to its customers, the economic value of Newington Station must be determined under market conditions that are uncertain. In addition, there are also several types of qualitative benefits to consider. LAI's study objectives are therefore six-fold:

- First, we review the history and operating characteristics of Newington Station.
- Second, we review the Station's recent operating and financial performance both in terms of traditional cost-of-service regulation and from an economics perspective.

[1] See Commission Order No. 25,061 issued on December 31, 2009, Docket No. DE 09-180.

- Third, we assess the sources of value associated with PSNH's continued operation of the Station on a qualitative basis, in particular, Newington's dispatch flexibility and dual fuel capability.
- Fourth, we estimate the economic value of Newington Station on a quantitative basis when it is operated in order to minimize energy costs.
- Fifth, we assess the additional risk reduction value of Newington Station as a type of insurance protection against potential adverse market conditions.
- Sixth, we evaluate the capacity price suppression benefit of keeping Newington Station in operation.

For purposes of this study, the alternative to PSNH's continued ownership and operation of Newington Station is either to retire the unit or to mothball it.[2] LAI's scope for this CUO study excluded portfolio considerations of Newington Station's value within PSNH's portfolio of other generation station assets, bilateral contracts, and load obligations. Over the ten-year planning horizon, continued ownership and operation of Newington Station provides PSNH's customers with various physical, financial, and strategic benefits, including the potential for additional generation at the site and/or repowering of Newington Station. While there are many different component costs associated with retirement, quantification of the costs associated with Station retirement is not part of this study. Likewise, LAI has not explored the economic merit of adding new generation at Newington Station or converting the Station to combined cycle generation.

## A.2. Approach

Emphasis has been placed on quantification of the expected economic value and the risk management value associated with flexible scheduling and operation of Newington Station in the face of market uncertainties. The quantitative analysis of the economic value of Newington Station performed by LAI has three components: first, economic value of flexible operation of the Station in the face of market uncertainties; second, the insurance value of adjusting the operating strategy of the Station in order to provide additional market risk protection against adverse outcomes at stressful times; and, third, capacity price suppression benefits.

To calculate the expected economic value of operational flexibility for the Station under conditions of market uncertainty, LAI performed a ROV analysis. ROV is a technique commonly applied by industry participants in order to estimate power plant asset values and for making investment or retirement decisions. ROV analysis captures value that typically goes unrecognized when traditional deterministic discounted cash flow (DCF) analysis is performed.

To estimate some of the additional insurance-like value of the Station not embedded in the ROV analysis, LAI has used a risk premium charge that is indicative of those included in energy load-following contracts.

[2] PSNH is not required to include an analysis of divestiture in its LCIRP as set forth in Order No. 24,695. Docket No. DE 07-108, Order No. 24,945, slip op. at 16 (February 27, 2009).

Quantification of the capacity price suppression benefit of retaining Newington Station in operation was performed by LAI using its model of ISO-NE's Forward Capacity Market (FCM).

This CUO study is based on historical and projected financial and operating data provided by PSNH. LAI has been responsible for the development of an independent forecast of capacity prices in New England and calibration of Day Ahead (DA) and RT energy prices and fuel prices at Newington Station to available forward market energy and fuel prices. Based on these inputs, LAI performed Monte Carlo simulation modeling of the value of Newington Station over the ten-year planning horizon, 2011 through 2020.

## B. Executive Summary

*Whether or not the ongoing value ascribable to PSNH's continued ownership and operation of Newington Station is greater than the costs borne by its customers is the central question in this evaluation.* On a prospective basis, Newington Station is expected to provide PSNH's retail customers with both physical and financial protection in light of volatile wholesale energy and capacity prices, both in New Hampshire and New England as a whole. In LAI's view, prospective wholesale market dynamics over the study period, 2011 through 2020, are likely to remain both unpredictable and volatile. PSNH's ownership and continued operation of Newington Station confers positive value both to customers and the region.

Based on the quantitative analysis, highlights of the CUO analysis conducted by LAI are as follows:

- Newington Station provides PSNH's customers with 400 MW of capacity at a largely known cost, therefore providing a physical hedge against regulatory uncertainty associated with ISO-NE's administration of the FCM. While capacity prices are known with certainty for the next few years, many uncertainty factors have the potential to exert significant upward pressure on capacity prices from 2016 through 2020. Continued operation of Newington Station shields PSNH's customers from materially adverse economic consequences that may arise from evolving capacity market dynamics in New England. On an expected value basis, the net value of the physical hedge is about $31 million. Under plausible worst case conditions from the standpoint of PSNH's customers, the net value of the physical capacity hedge is about $54 million.

- The expected net present value (NPV) of the incremental revenue requirements indicates substantial economic benefits are associated with PSNH's continued operation of Newington Station. The expected NPV is $152 million.

- There is virtually no risk of actual benefits resulting in a negative NPV. Simulation of market prices for capacity, energy, and fuels results in a 0% probability that the NPV of benefits will be negative. There is a 5% probability of an NPV outcome between zero and $25 million, and a 43% probability of an NPV between $25 million and $75 million. The median result is $80 million. With respect to an "earnings surprise" related to continued operation of the Station, there is a 5% probability of an NPV greater than $498 million. One reason why the NPV benefits are always positive from the customers' perspective is that Newington Station's sunk costs are excluded from the determination of going-forward cash costs through 2020.

- The risk of market based revenues being lower than Newington Station's incremental revenue requirement in any single year over the ten year study period is low. This is a result of the anticipated deterioration in capacity prices associated with the MW overhang in New England and ISO-NE's FCM restructuring proposal. On an expected value basis, Newington Station *always* shows that market based revenues are higher than its incremental revenue requirement. Simulation indicates only a 6% chance that market based revenues come in lower than

Newington Station's incremental revenue requirement in either 2017 or 2018, evaluated separately.

- The distribution of economic benefits on an NPV or year-by-year basis is heavily skewed toward relatively small positive outcomes. Given Newington Station's operational characteristics and the range of anticipated capacity prices in New England over the study period, there is only a 25% chance of an NPV greater than $200 million.

- A large portion of the net benefit of Newington Station's continued operation is derived from its ability to operate flexibly in the DA and RT energy markets. The present value of fixed costs (direct and indirect fixed O&M, property taxes, and incremental depreciation and return on rate base) of $80.4 million is offset by an expected value of capacity market revenues of $111.2 million, for a $30.8 million benefit. The remaining $121.5 million in expected value of net benefit is derived from net margins earned in the energy and ancillary service markets, and reflects the physical option values arising from the Station's operational dispatch flexibility and its ability to burn natural gas and/or oil, including adjusting the blend of both fuels on-the-fly. The Station's operational flexibility allows it to serve as a physical hedge against volatile DAM and RTM energy prices, as well as volatile and unpredictable trends in the natural gas and oil commodity markets.

- The additional insurance-like or financial hedge value of Newington Station as a substitute for energy load-following contracts is roughly estimated to be a risk premium equivalent to about 10% of the price of monthly on-peak contracts.

- From PSNH's customers' perspective, the positive expected NPV, coupled with the wide and skewed dispersion of potential economic results around the expected value, supports continued operation of Newington Station through 2020.

In addition to the more readily quantified benefits of continued operation, Newington Station also provides other benefits that are reported on a qualitative basis, as follows:

- The operational flexibility to adjust bidding in the DAM also allows PSNH to operate Newington Station at critical times in a risk-averse manner to safeguard against bad economic outcomes in the RTM. The Station also serves to backstop at a known cost a forced outage at one of PSNH's other generating stations.

- While Newington Station is operational, PSNH customers benefit from the real option value associated with waiting for more information before making a retirement timing decision.

- Newington Station's participation in the FCM provides capacity price suppression benefits to PSNH's customers as well as to other customers throughout New Hampshire and New England.

- Newington Station's electrical interconnection yields transmission and distribution system reliability benefits. Likewise, Newington's flexible fuel mix and large on-site oil tankage provides energy diversity benefits when natural gas deliverability is constrained due to system maintenance or high demand periods, such as during a cold snap.

- Newington Station provides several types of operational support to the ISO-NE transmission system, including provision of load-following energy, and spinning reserve, automatic generator control (AGC), and volt ampere reactive (VAR) support.

- The Newington Station site has extra space available to allow for future opportunities at the site.

## C. Newington Station Profile and History

In this section, we summarize Newington's current station profile and key historical modifications of the physical plant and its operating role. In light of the research goals and objectives pertaining to Newington Station's value to PSNH's customers, emphasis is placed on the description of the Station's operational flexibility and fuel-switching/blending flexibility.

### C.1. Brief History of Newington Station

Newington Station is a single 400 MW unit that went into commercial operation in 1974. The unit was designed to burn crude oil and RFO. The unit was built for cycling duty. The unit added natural gas firing capability in 1992 and directly connected to the interstate gas transmission system in 1999. The direct connection to an interstate pipeline has allowed for significantly greater operational flexibility.

For the first 30 years Newington Station operated as an intermediate unit with a capacity factor between 25% and 65%. Relative to the cohort group of steam turbine generators in New England, the unit has relatively quick starting capability. Newington Station has cycled on and off line daily, as needed, and over its life has averaged about 115 starts per year. The unit also load-cycles, varying its output from 60 MW to 400 MW on an hourly or daily basis as needed.

Newington Station has in the past and continues to operate for the benefit of PSNH's default energy service customers. All costs and revenues of such operation flow to PSNH's default energy service customers.

The unit is an integral part of PSNH's Energy Service rate and supplemental purchase planning process. During the planning process for setting the next period Energy Service rate, if forward energy prices are higher than Newington's incremental energy prices, Newington Station is used to meet the needs of PSNH's default energy service load. If Newington's incremental energy prices are higher than forward energy prices, energy is purchased from the market in varying MW blocks or strips. During the Energy Service period, PSNH assesses its market position, thereby deciding to run Newington, purchase energy from the market, or do neither if customer load is lower than originally forecast and running Newington is not economic. For example, in 2006 and 2007, Newington's projected capacity factors during the Energy Service planning period were 28% and 22%, respectively. Daily management of Newington's output resulted in actual capacity factors in 2006 and 2007 that were 8% and 9%, respectively. The gap between the projected capacity factors and the actual capacity factors in 2006 and 2007 is explained by market prices being lower than originally forecast and the availability of market based energy at an all-in price lower than the incremental cost of producing energy from Newington Station.

In 2008 and 2009, Newington's projected and actual capacity factors were in the 3% to 5% range. Through the first eight months of 2010, Newington Station has operated more frequently. Newington Station's increased operation in 2010 is largely in response to the warmer-than-average temperatures, May through September, coupled with lower natural gas prices versus other units that can only burn oil, and the modifications that have been made to the plant operating characteristics including, reduced start-up times, reduced minimum run times, and operating at higher levels while burning natural gas..

## C.2. Physical Plant Characteristics

Newington Station is comprised of a single Combustion Engineering-designed tangentially-fired boiler with a single reheat section. The unit is capable of producing approximately 3 million pounds of steam per hour at 1,980 psi and 953ºF. The turbine generator was designed by Westinghouse Electric and includes a high pressure / intermediate pressure turbine, a low pressure (LP) turbine, generator, and rotating exciter.

Emissions reductions at Newington Station began with the ability to burn natural gas and the installation of new gas lines and burners in 1992. Since that time, in order to meet the increasingly stringent air emissions requirements into the foreseeable future, low $NO_x$ burners, an overfire air system, additional sootblowers, and a water tempering system have been added. The emissions control system on Newington's Unit 1 includes an electrostatic precipitator (ESP), for the reduction of particulate emissions, which was not typical for similar oil-fired units built in the 1970s. In 2005, the previous practice of re-injecting the flyash into the boiler was discontinued, with the installation of an ash collection system on the precipitator.[3]

Newington Station is connected to the 345 kV transmission system through a 24.5 / 345 kV main step-up transformer. The Station also has access to the 115 kV system through the supply of power from the 115 kV system through two full size station service transformers via 115/4.16 kV step-down transformation. The transformers reduce the voltage to 4.16 kV before power enters the station. Minimal maintenance to the transformer has been required. The original electrical cabling between the generator and the main transformer was replaced by a Phase Buss duct in the mid 1980s.

Newington Station has two load centers for in-station electrical power to equipment, rated at 4,160 volts and 480 volts. The electrical equipment throughout the plant is supplied by various breakers and load centers. New protective relays and sensors have been installed to improve safety due to a recent OSHA arc flash study recommendations.

PSNH maintains a dedicated material inventory at Newington Station. Material in stock includes spare parts as well as critical spare assemblies required to maintain the availability and reliability of the Station.

## C.3. Operational Flexibility

Newington Station is capable of quick start-up and shut down as well as a wide range of mid-range load changes. In daily scheduling, the Station also has the capability to provide AGC to ISO-NE, as well as spinning reserve and VAR support. Newington Station has a

[3] This system has eliminated the need for the previous bi-annual ash cleaning outages and the annual waterwashing of the boiler, and has significantly reduced both $NO_x$ and particulate emissions from the unit.

minimum load of 15% of its maximum generation capability of 400.2 MW, about 60 MW.[4] Among the cohort group of dual fuel capable steam turbine generators in New England, Newington Station is one of the most flexible generation units.

Newington Station is dispatched as required by ISO-NE to meet intermediate and peak demand requirements. Newington Station has the capability to start up and shut down each day. The Station has historically averaged about 115 startups annually. The Station has a 12-hour cold start-up time and a 4-hour hot start-up time. Newington's minimum run time is 6 hours and minimum shutdown time is 4 hours. The Station is able to ramp up and down at a rate of 3 MW per minute between 60 MW and 400 MW. Within Newington's AGC capacity range, the Station can ramp at 5 MW per minute between 150 MW and 390 MW for regulation service.

## C.4. Dual Fuel Capability and Flexibility

Newington Station has the capability to fire on RFO and/or natural gas. The Station also has significant flexibility for switching between fuels or using a blend of both fuels. Fuel switching or blending can be performed quickly during operation without restriction.

### C.4.1. Oil Supply and Storage

Newington Station has four bulk fuel oil storage tanks that have a combined working capacity of 730,000 barrels. Newington Station utilizes the deep water marine terminal located across the street at PSNH's Schiller Station in Portsmouth, New Hampshire, for the receipt of No. 6 fuel oil. The terminal can accommodate ships carrying up to 250,000 barrels (10.5 million gallons) of oil as well as barges carrying lesser amounts. A piping system interconnects all four tanks, which allows for oil transference and blending. The blending capability allows for the purchase of lower-priced fuels in conformance with all environmental and permit requirements. Fuel oil is transferred on a daily or as needed basis to the Newington on-site day tank, where it is used in Newington's boiler. At full load on oil only, Newington Station would use about 17,000 barrels of oil per day. The capacity of the four oil storage tanks is sufficient to sustain Newington Station's operations at full-load operation mode for a maximum of 50 days, and 10 days when at minimum inventory levels.

### C.4.2. Natural Gas Supply and Scheduling

In 1999, Newington Station was directly connected to the Portland Natural Gas Transmission System (PNGTS), a high-pressure interstate pipeline in New England designed to transport natural gas from western Canada to Northern New England. The Station is located on the jointly-owned portion of the pipeline owned by PNGTS and Maritimes & Northeast (M&N) Pipeline. PNGTS delivers natural gas that is produced from other producing basins as well as western Canada.

[4] Other steam turbine generators previously divested by electric utilities in New England have minimum loads generally in the range of 40% to 50% of their nameplate generation.

The high pressure gas line lateral located on site is more than adequate to supply the required volume of gas. No supplemental on-site pressure boosting is needed to ensure pressure adequacy at the Station. Before entering Newington Station, the gas pressure is reduced to approximately 50 psi in two separate pressure reducing stations located on site.[5] When the Station burns natural gas, PSNH has the option of obtaining the supply under PNGTS's interruptible transportation (IT) service arrangement.

PSNH has also entered into flexible, third-party arrangements with marketers doing business on PNGTS and other pipelines serving New England. Except during cold snaps, PSNH has been able to provide natural gas to Newington Station as needed.[6] PSNH's flexible arrangements with third party suppliers protect its customers from the incurrence of substantial fixed cost obligations associated with the ability to use natural gas, as well as the flexibility related to using natural gas non-ratably.[7] The ability to burn gas non-ratably shields Newington Station from costly pipeline penalties and cash-out payments for daily imbalances.

### C.4.3. Dual Fuel Switching and Blending Flexibility

Newington Station can burn either natural gas or RFO alone or natural gas in combination with oil. The percentage of each fuel can be adjusted on-the-fly across the full operating range of the unit and requires no special preparations provided that certain limits are observed. Consistent with Newington's state operating permit, which contains limits specific to fuel and fuel blending, Newington's operational limits are:

- When firing on oil only, the boiler is able to achieve full load capacity at 400 MW.
- When firing on natural gas only, the Station can produce 320 MW, about 80% of its rated capability, and uses 86,000 dekatherms (Dth) per day.
- When firing a combination of natural gas and oil using the maximum volume of gas (equivalent to 80% of full load), with the remainder being oil, the unit is able to achieve 90% of full load capacity, or 360 MW.
- To operate at full load capacity using a gas and oil combination, the natural gas input is limited to no more than 50% of the total heat input to avoid operational and maintenance problems.

## C.5. Environmental

Air and water emissions from the facilities are governed by federal and state legislation and regulations. Newington Station is subject to the requirements under the Title IV Acid Rain section of the Clean Air Act of 1990, and the federal cap and trade program for sulfur dioxide ($SO_2$). Newington Station currently operates under a Title V Operating Permit that

---

[5] Spectra Energy, the owner of M&N and the Joint Facilities System, operates the pressure reducing stations.

[6] Under third-party marketer agreements, PSNH pays a market based price indexed to Tennessee Zone 6-New England for natural gas, transportation, and daily scheduling flexibility.

[7] Ratable-take restrictions limit the hourly use of gas to 1/24$^{th}$ the Maximum Daily Quantity or confirmation quantity. The scheduling of gas non-ratably provides Newington Station with the ability to use much more than 1/24$^{th}$ of the confirmation quantity in any hour and 100% of the confirmation quantity in fewer than 24 hours.

was issued in March 2007, with a minor modification in January 2010. The permit expires March 31, 2012. The Station may continue to operate after that date with a complete application submitted to the New Hampshire Department of Environmental Services, Air Resources Division (NHDES-ARD). Based on the submitted application, NHDES-ARD would begin the permit renewal process.

The emissions control systems at Newington Station include an electrostatic precipitator (ESP) for the reduction of particulate emissions (PM) and various $NO_x$ emissions controls, including waterwall soot blowers to remove ash deposits from the walls, arch blowers, low-$NO_x$ burners, a water-tempering system, and an over-fire air system. Also, a fly ash collection system has been installed to replace the practice of re-injecting the fly ash back into the furnace which has significantly reduced furnace fouling and reduced $NO_x$ levels when firing on oil, natural gas, or a combination thereof. Employing these various methods, PSNH has been able to reduce the amount of $NO_x$ emitted by Newington Station by more than 60%. The current $NO_x$ limits are 0.35 pounds/MMBtu when burning oil alone and 0.25 pounds/MMBtu when burning oil in combination with natural gas or natural gas alone. Particulate matter (PM) emissions are reduced by 90% as a result of the installation of the fly ash collection system.

PSNH's generation plants have a combined annual $SO_2$ emission limit of 55,150 tons. Projected and actual $SO_2$ emissions and dispatch costs are reviewed at least monthly. At Newington Station, $SO_2$ emission compliance is achieved by varying sulfur content of the fuel oils, while making cost effective choices of dispatch on oil or gas or dual fuel.

NHDES is currently preparing draft rules to address Regional Haze and BART. Newington Station is a BART eligible unit. In preparation of establishing these new rules, NHDES completed a BART analysis in January 2010. This analysis stated the current $NO_x$ RACT limitations for Newington are considered to represent BART control levels. NH's BART analysis also states, "In consideration of the facts that Unit NT1 already operates a fully functional ESP, that additional capital outlay for control cannot be economically justified at this time, and that any resulting benefit to visibility would be negligible, it is determined that the existing ESP fulfills BART requirements." Finally, the NHDES BART analysis states that "a more stringent sulfur dioxide emission limitation, to be effectuated through a proposed rule change, will require the facility to reduce average fuel sulfur content through appropriate adjustments to its fuel mix".[8] Newington Station's current permit limit is 2.0% sulfur content limit on residual fuel oil and 0.4% sulfur content limit on distillate fuel oil. However, PSNH already has a policy of procuring 1% sulfur RFO. Of note, EPA recently issued its proposed Transport Rule in July 2010, intended as a replacement to the Clean Air Interstate Rule (CAIR). New Hampshire is exempt from Transport Rule requirements. Therefore, Newington Station is not expected to be faced with implementing more stringent control strategies such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) for $NO_x$ control, additional restrictions on oil-firing for $SO_2$ control, or a retrofit of the ESP to increase the efficiency of PM removal.

[8] The previous price advantage PSNH had over other RFO-fired generation in New England by being able to burn higher sulfur oil which typically cost less than the lower sulfur oil has been eroded as a result of new refining processes. The price gap between 0.5% oil and 2% oil has narrowed due to the decline in usage of 2% oil.

When Newington Station is operating, it utilizes water from the Piscataqua River, a tidal river, for once-through, non-contact cooling of the steam that exits the low pressure turbine and enters the condenser. Under its National Pollutant Discharge Elimination System (NPDES) permit, Newington Station is allowed to warm the cooling water temperature by 25° F from the time it enters Newington Station to the time it exits the facility. The temperature of the returning water is also limited to 95° F. The unit can routinely operate within these parameters. The NPDES permit allows for the on-site treatment of process water prior to being returned to the river. Sewage from Newington Station is sent to the local municipal waste water treatment plant.

## D. Recent Financial and Operational Performance of Newington Station

In this section, LAI first reviews the financial performance of Newington Station over the past five years, and its operational performance over the past ten years. Second, LAI discusses the appropriate financial evaluation criterion and key operational performance criteria for measuring the economic benefits of continued unit operation.

### D.1. Recent Financial Performance

Newington Station is part of PSNH's regulated generation fleet. PSNH's regulated generation expenses are recovered through PSNH's Energy Service rate from customers that receive their energy from PSNH. Typical expenses for PSNH's generating stations include fuel and non-fuel operations and maintenance expenses, property taxes, and recovery of previous capital expenditures. In addition, PSNH is allowed a regulated rate of return on the undepreciated balance of previous capital investments. PSNH's generating stations participate in the ISO-NE administered wholesale markets. This participation yields revenue from the sale of energy, capacity, and ancillary services.[9] The revenues realized by PSNH from the sale of wholesale products from Newington Station are used to offset Station expenses. Newington Station has in the past allowed other utilities to take title to segments of its generation capability for a fee. No such contract exists at present.

#### D.1.1. Total Revenue Requirements Perspective for Rate Setting

For the purpose of rate-setting, PSNH utilizes a traditional revenue-requirements approach to determine the expenses, return on investment, and revenues received by its assets. Revenue requirements are typically calculated for PSNH's total regulated generation fleet during the Energy Service rate setting process. Revenue requirements are not typically tracked on a station or unit specific basis, though PSNH has in the past provided responses to data requests asking for the revenue requirements related to Newington Station. In order to perform that analysis, assumptions are made as to Newington Station's portion of PSNH's total fleet costs for items such as property taxes, emission allowances, and materials and supplies, as well as being allocated a share of PSNH's and NU's administrative and general expenses. Generally, PSNH's total fleet costs are apportioned or allocated based on Newington Station's size or output level in comparison to the fleet.

[9] Revenue from the sale of ancillary services includes spinning reserves, AGC, and VAR support.

Exhibit G.1 shows the estimated historical revenue requirements for Newington Station and wholesale product sales over the last five calendar years, 2005 through 2009, and the first six months of 2010. The revenues summarized toward the bottom of the table represent the Station's sale of energy, capacity, and ancillary services in the various wholesale product markets administered by ISO-NE. The exhibit shows an estimate of Newington Station's total historical revenue requirements as would be used in the Energy Service rate setting process. Data provided therein are approximately the same as data provided to the NHPUC in previous discovery requests.

**Exhibit G.1: Recent Revenue Requirements, 2005-2010 YTD June**

| (thousands of dollars) | 2005 | 2006 | 2007 | 2008 | 2009 | 1H 2010 |
|---|---|---|---|---|---|---|
| **Expenses** | | | | | | |
| Non-Fuel O&M with Indirects | | | | | | |
| Other than Emission Allowances | $13,350 | $9,136 | $7,640 | $7,863 | $7,697 | $2,900 |
| Emission Allowances Expense | $1,497 | $464 | $315 | ($32) | $288 | $49 |
| Total Non-Fuel O&M | $14,847 | $9,600 | $7,955 | $7,831 | $7,984 | $2,949 |
| Fuel and Fuel-Related Expense (Note 1) | $68,344 | $22,492 | $30,476 | $15,784 | $16,808 | $5,844 |
| Property Tax | $925 | $908 | $1,034 | $966 | $821 | $189 |
| Depreciation Expense | $3,408 | $3,447 | $3,300 | $8,868 | $8,934 | $4,464 |
| **Total Expenses** | **$87,524** | **$36,447** | **$42,765** | **$33,451** | **$34,547** | **$13,445** |
| **Plant Values** | | | | | | |
| Gross Plant Value | $139,989 | $140,340 | $160,000 | $143,944 | $144,307 | $144,161 |
| Accum. Depreciation | $71,739 | $74,382 | $99,000 | $85,714 | $94,089 | $98,576 |
| Net Plant Value | $68,250 | $65,958 | $61,000 | $58,230 | $50,218 | $45,585 |
| Working Capital | $1,830 | $1,184 | $981 | $1,181 | $1,215 | $942 |
| Year End Fuel Inventory | $23,108 | $28,079 | $18,477 | $32,019 | $26,879 | $25,143 |
| Emissions Inventory (NOx, SOx, CO2) | $5,917 | $1,280 | $1,408 | $604 | $785 | $367 |
| Accumulated Deferred Income Tax | ($5,467) | ($3,410) | ($3,520) | ($4,536) | ($4,424) | ($3,656) |
| Material & Supply Inventory | $4,899 | $3,636 | $4,024 | $4,287 | $4,571 | $3,370 |
| **Total Rate Base** | $98,538 | $96,726 | $82,370 | $91,785 | $79,244 | $71,751 |
| Average Return on Rate Base | 10.91% | 10.61% | 11.13% | 10.80% | 10.98% | 10.63% |
| Return on Rate Base | **$10,750** | **$10,263** | **$9,168** | **$9,913** | **$8,701** | **$3,814** |
| **Revenue Requirements** | **$98,274** | **$46,710** | **$51,933** | **$43,363** | **$43,248** | **$17,259** |
| **Revenues** | | | | | | |
| Energy | $88,928 | $21,304 | $27,013 | $14,654 | $13,591 | $5,439 |
| Capacity | $927 | $2,224 | $14,023 | $15,840 | $18,537 | $9,591 |
| Ancillary | $381 | $110 | $28 | $13 | $99 | $60 |
| Unitil Entitlement | $3,386 | $2,336 | $2,610 | $1,810 | $0 | $0 |
| **Total Revenue** | **$93,621** | **$25,974** | **$43,674** | **$32,317** | **$32,228** | **$15,090** |

Note: Fuel costs for 2007 total $36,384K but are shown net of $5,908K related to oil resale transactions.

000196

### D.1.2. Treatment of Expenses and Revenues for CUO Analysis

This section discusses the various expense, rate base, and revenue line items shown in Exhibit G.1 with respect to Newington Station's historical revenue requirements and revenues. While the categories of expenses, rate base elements, and revenue sources are the same in a CUO study as in a revenue-requirements study, there are certain analytic differences in what expenses and rate base elements should be included in a CUO analysis. This section describes the "bridge" to the CUO analysis, whereby certain of the expense and rate base items are necessarily treated differently. The focus here is on the distinction between total costs and the incremental or going-forward costs appropriately allocable to PSNH's customers in the broader context of the CUO analysis.

**O&M Expenses**. Non-fuel O&M expenses associated with Newington Station include labor and benefits, scheduled and major maintenance, emission allowances, and an allocation of PSNH's and NU's administrative and general expenses. Primarily due to prior capital investments in Newington Station being depreciated and the decreased capacity factor experienced in the last few years, the current costs of operating Newington Station are low. Staffing reductions implemented over the past few years have resulted in additional savings. Direct, loaded, fixed O&M costs going forward are currently estimated to be less than $7.5 million per year. This compares favorably to $8.0 million in 2009, adjusted for inflation. Assuming continued operation, O&M expenses continue to be incurred over the forecast period. Emissions allowance expense includes the cost of any federal or state allowances for emissions from Newington Station. These typically include $NO_x$, $SO_x$, and $CO_2$ expenses associated with the annual tons of Newington Station's emissions. In the going forward CUO analysis, emission expenses have been simulated over the forecast period for multiple scenarios and are included with the fuel-related expenses.

**Fuel and Fuel-Related Expenses**. Fuel and fuel-related O&M expenses are variable costs associated with Newington Station operations and include fuel purchases, shipping, handling, and fuel additives needed to generate electricity by operating the plant and manage emissions. In the CUO analysis, fuel and fuel-related O&M expenses have been simulated over the forecast period for multiple scenarios.

**Property Tax Expense**. The property tax expense listed in Exhibit G.1 is Newington Station's property tax based on the combined property tax assessments by the Town of Newington and the State of New Hampshire. PSNH has had frequent negotiations with the Town of Newington to keep tax bills reasonably in check. This is done to ensure that Newington's assessors remain informed regarding the issues that impact the market value of Newington Station. In the CUO analysis, property taxes continue to be paid for Newington Station if the unit continues to operate.

**Depreciation Expense**. The depreciation expense listed in Exhibit G.1 is the amount of depreciation that customers pay for plant capital costs and capital addition investments in Newington Station. The remaining book life for depreciation purposes is currently set at 2014 and therefore the undepreciated plant balance is spread over that remaining time period. PSNH periodically looks at the expected life as defined on the books and adjusts the end date defined for depreciation purposes. For purposes of this CUO analysis, when the


000197

Station's retirement is contemplated, the assumption is that the remaining undepreciated plant value would still be recovered. Hence, in the CUO analysis, depreciation related to *past* capital additions is excluded. However, depreciation associated with any *new* or going-forward capital investment made to keep the unit operational during the study period is included.

**Return on Rate Base**. PSNH earns a return on its investment (net plant value) in Newington Station, and associated working capital, ADIT, and fuel, emission allowances, and materials and supplies (M&S) year-end remaining inventories.

**Working Capital**. Working capital is the amount of funds that PSNH must have available to pay for non-fuel O&M expenses. PSNH maintains a working capital level of 45 days worth of O&M expense. This fund would exist if the unit continues to operate and have an O&M requirement.

**Fuel Inventory**. Newington Station maintains a certain level of fuel oil in its tanks for the unit to run.[10] For the historical values in Exhibit G.1, the value of the fuel inventory was calculated using the average price of fuel in the tank at the end of each period. If Newington Station were retired, the oil inventory would be sold, thereby reducing PSNH's rate base by the amount PSNH would be able to realize from the resale of its RFO inventory.

**Emission Allowances Inventory**. If PSNH carries an inventory of unused emissions credits, PSNH is allowed to earn a return on the rate base item since the company has purchased the credits in advance. The Newington Station historical emissions allowance inventory value is its emissions-apportioned share of the total generating station inventory. If Newington Station were retired, the emissions inventory would remain for use by the other generating stations. Going forward, the CUO analysis assumes emission allowances are expensed as incurred and not inventoried.

**Accelerated Depreciation Income Tax**. The historical ADIT values shown in Exhibit G.1 are Newington's apportioned share of total PSNH generation station ADIT value, based on Newington's share of net plant in relation to PSNH's generation stations' total net plant values. The included taxes are related to timing differences between book and tax depreciation.

**M&S Inventory**. The M&S inventory is the amount of materials and supplies at Newington Station. The historical M&S inventory values shown in Exhibit G.1 are Newington's apportioned share of total PSNH generation station inventories, based on Newington's share of net plant in relation to PSNH's generation stations' total net plant values.[11]

[10] At the end of 2009, Newington Station had about 485,000 barrels of oil in storage, about 30 days of inventory.

[11] Newington Station would carry M&S inventory equal to the current actual level of inventory on hand of about $2.5 million going forward in the CUO analysis.

**Rate of Return on Rate Base**. PSNH is allowed to earn a return on the undepreciated balance of capital additions. As noted above under depreciation expense, in the CUO analysis, PSNH would earn a return on the undepreciated balance of any new capital investments needed to keep Newington Station operating. The average return on rate base shown in Exhibit G.1 is calculated based on the return on rate base that Newington Station actually received and Newington Station's total rate base. LAI used a rate of return based on the allowed return on equity for PSNH's generation segment and the actual cost of debt.[12]

**Revenues**. PSNH, and by extension Newington Station, is a participant in the New England wholesale electricity market administered by ISO-NE. PSNH receives market and entitlement revenues attributable to Newington Station that offset expense and return. These typically include ISO-NE energy market, forward capacity market, ancillary market, and entitlement revenues. Each revenue source is described in more detail below.

> **Energy Revenue**. To serve PSNH's customers, Newington Station produces energy which is sold into the ISO-NE wholesale energy market. As noted above, Newington Station's fuel expense is paid for by customers taking Energy Service from PSNH. All energy market revenues are credited back to Energy Service customers. Newington's capacity factor and energy market prices affect the level of revenue received for the energy produced by Newington Station. To illustrate, in 2005, Newington Station had a capacity factor of approximately 34% and average energy revenue of $75.84/MWh, resulting in total energy revenue around $88 million. In 2009, Newington Station's capacity factor was approximately 5% and average energy revenue was $74.27, resulting in $13 million in energy revenue.
>
> If Newington Station were not available, PSNH would need to purchase the energy from the market to the extent that Newington Station would have served PSNH's Energy Service customer load. Additionally, to the extent Newington Station produced energy beyond that amount required to serve Energy Service customer load, customers would lose any resulting profits (energy revenue less fuel cost) from the wholesale market. However, with the unit continuing to operate, Newington Station's generation would continue to benefit PSNH's Energy Service customers. The level of net benefit from the energy market will vary with fuel, emission allowance, and energy price assumptions.
>
> **Capacity Revenue**. Newington Station's participation in the ISO-NE capacity market satisfies a portion of PSNH's Energy Service customers' capacity market obligation. The prices paid to capacity resources and billed to load serving entities are essentially the same. Under this arrangement Newington Station's capacity revenues offset an equal amount of PSNH's Energy Service payments.
>
> If Newington Station were not available, PSNH would no longer receive capacity revenues for Newington Station, which offset payments made by PSNH for serving Energy Service customers, since it would still be paying its share of the capacity

[12] Cost of capital and capital structure as outlined in DE 09-035 PSNH Distribution Rate Case Settlement Agreement. Generation assets are allowed a risk premium of 14 basis points above the authorized distribution rate of return.

market costs. Further, the capacity price with Newington Station retired may not be the same as the capacity price with Newington Station continuing to operate. This is because the ISO-NE capacity market clearing price is established through an auction process and Newington Station's participation in the auction could affect the clearing price. To the extent Newington Station's participation in the auction influences the clearing price, all load in ISO-NE will pay a price different than if Newington Station were to retire. A more detailed discussion of this impact is provided in Section F, including quantification of Newington Station's possible impact on the capacity price and the cost impact for New Hampshire load.

**Ancillary Services Revenue**. Newington Station receives revenues for providing ancillary services. Specifically, the Station provides AGC, spinning reserves, and VARs. By providing spinning reserve Newington Station can also satisfy 10 and 30 minute non-spinning operating reserves. In this CUO analysis, ancillary services revenues are assumed to be constant over time.

**Unitil Entitlement**. PSNH contracted with Unitil for a 10 MW share of Newington Station's output. The entitlement contract ended in 2008. Since this contract occurred in the past and is now expired, it is not considered an ongoing revenue source for the continued operation analysis. Future similar sales could occur but are not included in this CUO analysis.

### D.1.3. Backcast Example of Going Forward Costs and Benefits Perspective for CUO Analysis

In Exhibit G.1 LAI does not show a "bottom line," that is, the net cost or benefit to customers that represents the difference between Total Revenue and Revenue Requirements. Such a calculation is not valid for a CUO study. As discussed in Section D.1.2, in a CUO study only going-forward costs matter. Therefore sunk costs should be ignored. Depreciation and return on rate base charges related to past capitalized expenditures are not relevant to the decision of whether the unit should continue to operate from the customers' perspective. Whether the unit continues to operate or is removed from rate base, customers will incur the cost of depreciation of and return on the undepreciated plant balance.

Inclusion or exclusion of depreciation and rate of return on rate base for past investments is related to the different purposes of the rate setting and CUO analyses. A simple review of the historical revenue requirements shown in Exhibit G.1 for Newington Station relative to its historical capacity and energy market revenues does not provide an accurate assessment of the merits of continued operation versus the potential retirement of the Station. Rate setting calls for a *total* revenue requirements value calculated as a *known* or deterministic stream of past values. CUO analysis, on the other hand, calls for *incremental* or "going forward" costs and benefits calculated prospectively as an *uncertain* stream of future values. This section only discusses the total versus incremental aspect of the two key differences in the evaluation criterion between a revenue requirements study and a CUO study. The certain versus uncertain stream of values distinction will be addressed in Section E, in the context of explaining the various sources of ROV for Newington Station.

Historical records show that Newington had expenses of $34.5 million in 2009. Expenses ranged from $33.5 million to $87.5 million in the prior four years. These expenses include depreciation expense, which was about $8.9 million in 2008 and 2009, but much lower in the prior years. Revenue requirements also include return on rate base, which totaled $8.7 million in 2009, down from as much as $10.8 million in the four preceding years. Hence, the total revenue requirement for Newington Station was $43.2 million in 2009. In 2009, the market value of the wholesale products sold through ISO-NE's capacity and energy markets totaled $32.2 million. The difference between the revenue requirement and the value of the wholesale products in 2009 was $11.0 million. The net revenue requirement was about the same in 2008 and has fluctuated in the prior years over the five-year historical period. While this calculation is appropriate as part of the rate-setting procedure for PSNH, it does *not* signify a negative net benefit borne by PSNH's customers of continued operation of Newington Station.

A positive net revenue requirement does not mean that PSNH's customers would be better off if Newington Station had been retired prior to the beginning of 2010. The net plant book value was $50.2 million at the end of 2009. Consistent with public utility law, if PSNH were to accelerate the retirement of Newington Station, this value net of salvage, would be recovered from PSNH's customers over some number of years as a stranded cost. A return on the remaining book value of Newington Station would be included in PSNH's rates. If we assume that salvage value is negligible, then the present value of the stranded cost recovery would be approximately the same as the present value of the future depreciation and return on net plant value revenue requirements for Newington Station.

To further illustrate the distinction between a rate-setting analysis and a CUO analysis, LAI has "backcast" Newington Station's "going-forward" costs over the historic period, 2005 through 2009, shown in Exhibit G.2. From a CUO study perspective, the meaningful measure of the annual "going-forward" net costs of the station would be its expected expenses, including depreciation of only *incremental* capitalized expenditures made from 2005 through 2009, plus return on incremental plant value, working capital, and inventory rate base, less market revenues, adjusted for any hedge or insurance value. In this simplified illustrative analysis, incremental capitalized expenditures are assumed to be zero. In actuality, PSNH incurred some capital expenditures during this period in order to maintain plant efficiency.[13] The purpose of this example is only to reinforce the explanation that depreciation and return on rate base for past investments are properly omitted from consideration in a CUO study.

For 2009, inventories and working capital was $29.0 million ($79.2 million total rate base less $50.2 million net plant value). Therefore, when we apply the return on rate base of about 11%, the return requirement is $3.2 million. Gross going forward costs are the sum of expenses, excluding depreciation, of $25.6 million, plus the $3.2 million inventories plus working capital return charge, or $28.8 million. With 2009 market revenues of $32.2 million – again, assuming no incremental capital expenditures – it would have provided a net benefit (reduction in net going forward costs) to customers of $3.4 million. Applying the same assumption of no capital expenditures from 2005 through 2009, the largest net benefit

[13] Also, we are using a single known historical outcome of operating expenses and revenues rather than considering the economic impacts of uncertainty on expected market valuation and additional insurance premium value.



000201

would have been $6.2 million in 2005. In four of five years Newington Station would have provided a net economic benefit to its customers. In one of the five years, 2006, Newington Station would have provided a net cost (disbenefit) when the annual net going-forward cost was $10.3 million. Over the past five years, the average net benefit would have been positive.

**Exhibit G.2: Recent Incremental Revenue Requirements, 2005-2009 (No CapEx)**

| | | | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|
| a | | Net Plant Value | $68,250 | $65,958 | $61,000 | $58,230 | $50,218 |
| b | | Average Rate of Return | 10.91% | 10.61% | 11.13% | 10.80% | 10.98% |
| c | | Total Expenses | $87,524 | $36,447 | $42,765 | $33,451 | $34,547 |
| d | | Less Depreciation Expense | $3,408 | $3,447 | $3,300 | $8,868 | $8,934 |
| e | e = c - d | Incremental Expenses | $84,116 | $33,000 | $39,465 | $24,582 | $25,613 |
| f | | Total Return on Rate Base | $10,750 | $10,263 | $9,168 | $9,913 | $8,701 |
| g | g = a * b | Less Return on Rate Base Net Plant Value | $7,446 | $6,998 | $6,789 | $6,289 | $5,514 |
| h | h = f - g | Return on Wkg Capital & Inventories | $3,304 | $3,265 | $2,378 | $3,624 | $3,187 |
| i | | Market Revenues | $93,621 | $25,974 | $43,674 | $32,317 | $32,228 |
| j | j = e + h - i | Incremental Revenue Requirements | ($6,201) | $10,291 | ($1,831) | ($4,111) | ($3,428) |

000202

## D.2. Recent Operational Performance

The request for this CUO study was triggered by the observation that the capacity factor of Newington Station has declined in recent years. A lower capacity factor reduces the economic attractiveness of the Station, all else equal, by increasing the average fixed cost per MWh. A key question is whether the recent downward trend in capacity factor represents a new, less utilized permanent state, or whether the lower recent capacity factors are transitory.

Importantly, capacity factor – defined as net energy generation divided by potential energy generation over all hours in the period – is not the only key physical operational indicator of Newington Station's value to customers. Other key physical operating performance indicators include service factor, availability, and number of starts. Service factor – defined as service hours divided by all hours in the period – is closely related to capacity factor but has the advantage of indicating, in relation to capacity factor, the amount of time the unit operates at less than full load. Operation at less than full load provides customer benefits by being able to quickly increase loading whenever the economic opportunity or reliability need arises in the real time market. The number of starts is also a useful indicator of the unit's value by showing the ability to take advantage of positive spark spreads.

Exhibit G.3 shows Newington Station's annual operating performance from 2000 through 2009, and monthly reporting for 2010 through July. Prior to 2003, Newington Station also had lower annual capacity factors than in the 2003 to 2005 period, when the Station operated as an intermediate unit. The changes in annual capacity factor from year to year are explained by several market and operational reasons. Market forces include volatile natural gas and oil prices, changing wholesale energy markets, and the addition of nearly 10,500 MW of efficient, combined cycle plants throughout New England over the six year period, 1999 through 2005. Operational reasons include varying availability and a 2010 decrease in cold start costs and more efficient dispatch. Availability was lower than usual from 2000 to 2002, primarily due to forced outages in 2000 and 2001 and planned outages in 2002 that included major capital investments. From 2004 through 2009, Newington Station used less than 25% natural gas in its annual average fuel mix, but with RFO prices twice as high as gas prices in 2010 to date, the Station has reversed that ratio by burning over 75% gas. Starting in 2010, dispatch efficiency has been improved by changing the fuel blending strategy and bidding strategy, as well as reducing cold start costs, so as to operate economically in more days. These recent changes have resulted in more of an improvement in service factor than for capacity factor. In July 2010, as a result of large spark spreads on gas, Newington had 20 starts, an average of about one per weekday, and a service factor over 35%.

While the annual average fuel price and fuel usage shares in the Exhibit G.3 table illustrate the relationship between relative fuel prices and fuel mix, the historical monthly data in the Exhibit G.4 chart demonstrates the ability of Newington Station to re-optimize its fuel mix whenever the oil/gas price parity ratio reverses.[14] Because natural gas prices are typically higher during the winter heating season while average RFO prices are fairly level year round, the day-to-day fluctuations in the economics of gas versus RFO are due both to the predictable seasonal pattern of gas prices and the high price volatility of both gas and RFO prices. Generally, as can be seen from the chart, gas usage occurs during the summer season when gas prices are at their seasonal low. Even when gas is cheaper, some RFO is usually burned in order to generate more than 320 MW, which is the maximum level on gas alone. In some periods, emissions or combustion testing required burning the more expensive fuel, and RFO may be burned when its fuel inventory cost is less than the spot price. Despite the exceptions, PSNH's adherence to minimization of cost principles by burning the lower cost fuel is readily apparent.

[14] The fuel price parity ratio is calculated on the basis of each fuel's price per MMBtu.

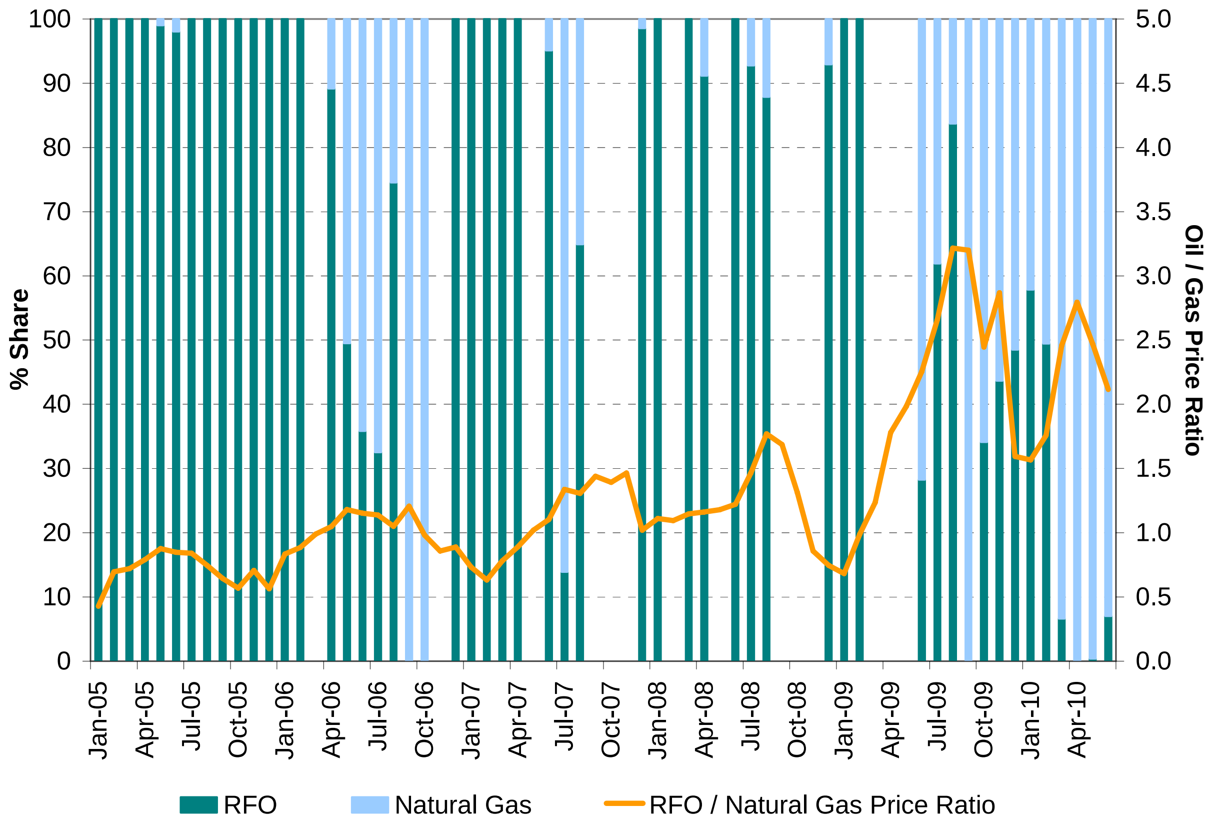
## Exhibit G.3: Newington Station Operating Performance, 2000-2010 YTD July

| Year | Capacity Factor (%) | Service Factor (%) | Avail-ability (%) | Starts | RFO Use Share (%) | #2 Oil Use Share (%) | Natural Gas Use Share (%) | Newington Average RFO Cost ($/MMbtu) | Newington Average Natural Gas Cost ($MMbtu) | Newington Average Energy Revenue ($/MWh) | Average Residual Oil Spot Price, NYH ($/MMbtu) | Average Natural Gas Spot Price, Dracut ($MMbtu) | Average On-Peak DA Price, Newington ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2000** | 13.0 | 22.8 | 37.2 | 116 | 83.2 | 2.0 | 14.8 | 3.31 | 3.51 | | 3.99 | | |
| **2001** | 12.8 | 24.0 | 65.6 | 62 | 87.4 | 2.3 | 10.3 | 3.57 | 2.39 | | 3.29 | | |
| **2002** | 19.0 | 31.7 | 79.0 | 135 | 83.3 | 2.1 | 14.5 | 3.59 | 3.86 | | 3.58 | 3.69 | |
| **2003** | 55.9 | 75.4 | 92.8 | 94 | 99.6 | 0.4 | 0.0 | 4.29 | N/A | | 4.37 | 6.44 | |
| **2004** | 50.2 | 71.7 | 93.7 | 122 | 99.5 | 0.5 | 0.0 | 4.25 | N/A | 54.42 | 4.44 | 6.76 | 55.83 |
| **2005** | 33.6 | 47.0 | 80.5 | 117 | 98.9 | 1.0 | 0.1 | 5.30 | 7.50 | 75.84 | 6.63 | 9.83 | 80.34 |
| **2006** | 8.0 | 14.6 | 95.4 | 85 | 72.3 | 3.3 | 24.4 | 6.16 | 7.07 | 75.14 | 7.30 | 7.15 | 65.04 |
| **2007** | 9.4 | 15.7 | 95.7 | 39 | 92.0 | 2.4 | 5.6 | 10.17 | 7.82 | 84.81 | 8.57 | 8.01 | 72.19 |
| **2008** | 3.3 | 6.2 | 88.9 | 23 | 89.0 | 6.3 | 4.7 | 10.60 | 12.68 | 124.16 | 12.14 | 9.73 | 87.16 |
| **2009** | 5.2 | 10.4 | 94.2 | 39 | 74.1 | 3.5 | 22.4 | 7.42 | 5.87 | 74.27 | 8.92 | 5.05 | 44.75 |
| **2010 YTD** | 5.4 | 13.6 | 99.2 | 54 | 21.6 | 5.4 | 73.0 | 7.83 | 5.99 | 81.83 | 11.29 | 5.24 | 52.83 |
| **2010** | | | | | | | | | | | | | |
| **Jan** | 2.9 | 7.4 | 99.9 | 4 | 49.5 | 14.4 | 36.1 | 6.50 | 7.48 | 84.77 | 11.41 | 7.28 | 64.81 |
| **Feb** | 4.0 | 12.3 | 100.0 | 7 | 44.9 | 9.1 | 46.0 | 8.88 | 6.99 | 58.01 | 11.04 | 6.28 | 55.55 |
| **Mar** | 1.7 | 3.5 | 100.0 | 2 | 6.2 | 6.0 | 87.8 | -51.95 | 6.56 | 96.25 | 11.41 | 4.64 | 40.71 |
| **Apr** | 0.0 | 0.0 | 100.0 | 0 | N/A | N/A | N/A | N/A | N/A | N/A | 12.11 | 4.34 | 38.15 |
| **May** | 4.0 | 13.1 | 100.0 | 8 | 0.4 | 4.7 | 95.0 | 6.46 | 5.44 | 62.44 | 11.10 | 4.50 | 43.52 |
| **Jun** | 9.8 | 23.3 | 95.3 | 13 | 6.7 | 3.8 | 89.4 | 9.61 | 5.81 | 72.88 | 10.79 | 5.10 | 53.57 |
| **Jul** | 15.1 | 35.6 | 98.9 | 20 | 27.4 | 3.0 | 69.6 | 9.61 | 5.95 | 96.12 | 11.07 | 4.96 | 74.40 |

Notes:

1. 2010 year-to-date values are through July.
2. Average spot fuel prices are from NYMEX and average on-peak energy prices from ISO-NE.
3. RFO cost is the actual cost form inventory, not the current market price.

**Exhibit G.4: Newington Station Fuel Mix and Spot Price Ratio, 2005-2010 YTD June**




## E. Qualitative Analysis of the Benefits of Newington Station

Newington Station provides a range of benefits to PSNH's customers, New Hampshire, and New England as a whole. This section discusses many of these benefits qualitatively. Section F analyzes the key benefits quantitatively.

### E.1. Operational Economic Value to PSNH Customers

Newington Station's operational economic value to PSNH's customers is defined here as the economic value the Station provides customers when operated so as to maximize its net revenue from operation. Economic value refers to the uncertain stream of cash flows that accrue to the benefit of PSNH's customers. The cash flows discussed in this section relate to spot market energy and ancillary service revenues and fuel costs, and capacity revenues. Consideration of additional, less-easily quantified insurance-like hedge value is discussed in Section E.2. The insurance or hedge value refers to the ability to narrow the distribution of outcomes – both favorable and unfavorable – rather than adding additional expected economic value. In fact, insurance or hedge strategies almost always have a significant economic cost. Risk management involves a tradeoff between maximizing expected economic value and minimizing the risk of much worse than expected outcomes.

In this section, the economic benefits of the Station are analyzed using the ROV approach for identifying and explaining the types of economic physical option benefits that Newington Station provides in relation to its energy and ancillary service product revenues, fuel costs, and capacity revenues.[15] Use of the alternative DCF analysis technique would fall short of capturing the economic value to PSNH's customers. The ROV conceptual framework is the accepted theoretical economic approach for the evaluation of a flexible generating unit – such as Newington Station – that provides various types of physical or real option values simply by remaining operational. The sources of real option values are embedded within the physical asset itself or its strategic management policy. The key sources of real option values provided by Newington Station's various types of operational flexibility are (1) output flexibility to vary its energy generation level and product mix, and (2) input flexibility to vary its fuel blend or switch between fuels.

Depending on the context, the ROV acronym may refer either to the valuation method, which actually measures total value (so-called "intrinsic" value plus option value), or to the magnitude of the real option premium value. In this section, we discuss real or physical options not in the context of providing a natural hedge, which they do provide, but in terms of the analytic approach for determining the full value of Newington Station. The other side of the coin of physical optionality – its financial insurance or hedge value in risk reduction – is discussed in Section E.2.

### E.1.1. Output Flexibility

Relative to the cohort group of steam turbine generators in New England, Newington Station has considerable output flexibility given its relatively quick cold and warm start times, its relatively rapid ramp rate, and relatively short minimum operation and minimum down times. These physical characteristics give the Station the ability to vary its generation level in order to maximize its net revenue from the energy and ancillary services markets. Newington's start times and start costs are low enough to support profitable dispatch in the RTM. More often, it has the flexibility after being committed for dispatch in the DAM to extend the scheduled run hours and/or increase its generation level in the RTM when RT prices are higher than the DA prices. Newington's wide operating range, 60 MW to 400 MW, allows the Station to achieve value by selling, committing, and scheduling energy in both the DAM and the RTM, as well as by selling ancillary services, *i.e.*, spinning reserve and AGC. Essentially, the Station has the multi-product flexibility to sell a variable mix of four products.

The core insight of ROV theory is that when a real (non-financial) asset, such as a physical asset or a patent right, faces an uncertain economic environment and the owner of the asset has flexibility in how the asset is used, a real option value exists. The techniques for qualitatively and quantitatively analyzing real option values are similar to those for analyzing different types of financial options. Importantly, the existence of a real option value requires both uncertainty and flexibility. One without the other does not produce a real option value. For example, a non-dispatchable generating station, such as a run-of-river hydro unit, windfarm, or nuclear plant, has no output option value. Whether energy

[15] ROV techniques were developed largely during the 1990s and have been applied to analyze the value of existing physical assets, such as power plants, and the optimal timing of new investment or retirement decisions.

prices are high or low, the station will generate the same amount of energy. In that case, traditional DCF valuation of its energy revenue based on expected energy output times expected energy price in each time period suffices. But for a fossil-fueled generating station, the dispatch flexibility of being able to temporarily shutdown or reduce output to minimum operating level whenever its spark spread is negative, provides extra net revenue in comparison to a station that cannot decrease its generation when it would run at a loss.

The greater the range of dispatch flexibility, given technical constraints and costs, such as startup time and cost, that effectively limit economic flexibility, the greater the unit's value.

### E.1.2. Dual Fuel Flexibility

Newington Station's dual fuel capability and blending flexibility provides economic, environmental, and reliability benefits. The Station can switch or blend fuels in response to daily changing fuel price ratios, or economically use higher-priced RFO to increase the load above 320 MW in response to a larger spark spread when natural gas is lower priced. If required to meet increasingly stringent air emission limits and/or mitigate higher emission allowance costs, PSNH can reduce the Station's operating time, reduce fuel consumption of oil, and/or increase fuel consumption of natural gas. And when either the supply of oil or natural gas is limited or interrupted, the other fuel may be used as a backup fuel.

PSNH's ability to transport under PNGTS's IT service or under third party arrangements with regional marketers supports the Station's scheduling flexibility in the DAM and RTM. During cold snaps when natural gas deliverability is constrained, PSNH uses its large oil storage infrastructure to serve the Station. Because PNGTS often has slack deliverability relative to other pipelines serving New England, PSNH is generally able to rely on its third party arrangements during the heating season, November through March. This locational advantage allows the Station to burn natural gas during the winter rather than oil whenever gas is less expensive. There are no pipeline deliverability constraints during the non-heating season, and therefore no procurement challenges or risk exposure associated with imbalance resolution, penalties, and cash-outs.

The ROV of fuel-blending or substitution flexibility is tied to the price volatilities of each fuel, and their correlation behavior. RFO and natural gas are generally positively correlated, with the degree of correlation increasing for longer durations. This means there is a tendency for unanticipated upward and downward movements to track together.[16] Despite the extent of any statistical correlation between RFO and natural gas prices, as Exhibit G.4 shows, there are both predictable seasonal cross-over points in price parity, and random fluctuations that cause one or the other fuel to be cheaper. The operational flexibility of Newington Station to economically optimize the fuel blend of RFO and gas is a source of ROV. The higher the fuel price volatilities, the greater the ROV.[17]

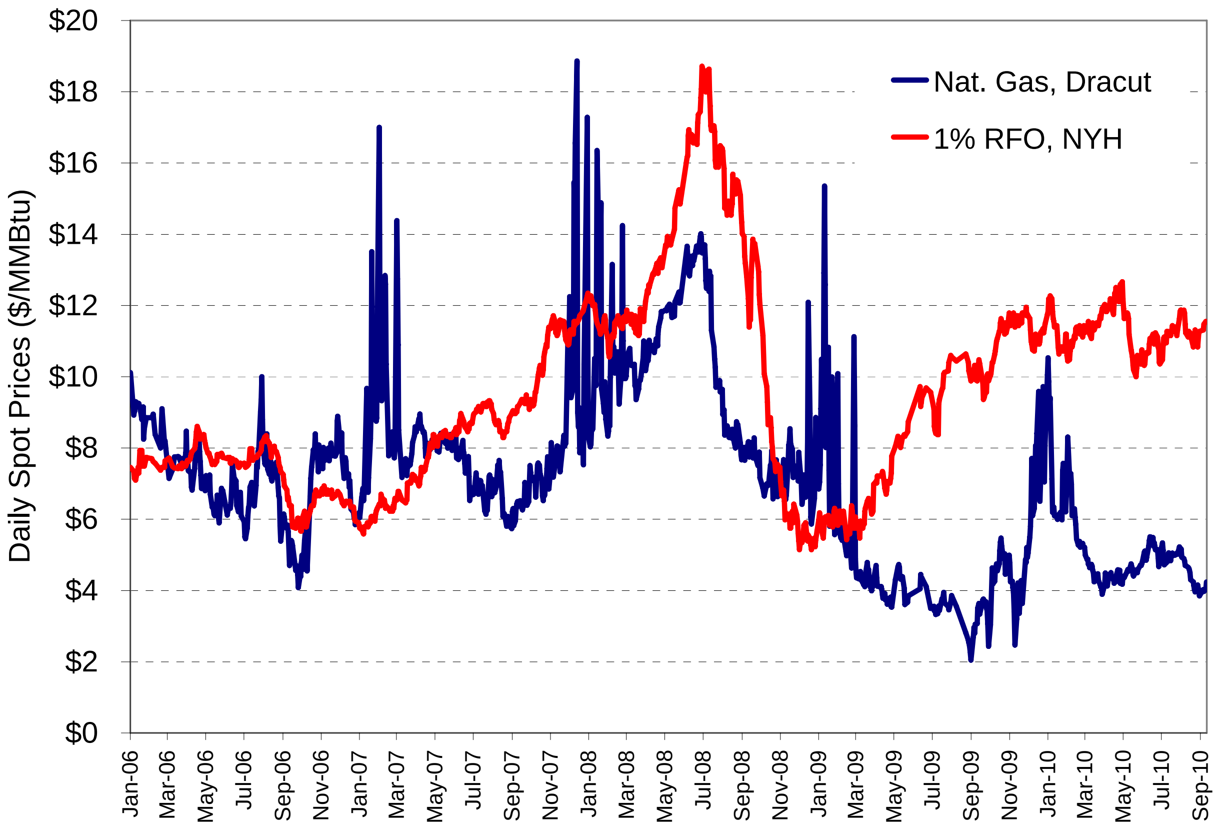
---

[16] The type of correlation may be that of "cointegration," an even tighter coupling of two variables, such that either their ratio or absolute spread tends to be fairly stable.

[17] This type of optionality is similar to that of a financial exchange option, where the payoff is allowed to be on the more favorable of two underlying price indexes. Due to the side constraints of a variable heat rate at different loading levels and the absolute limit on natural gas use, calculation of

In addition to extra financial value by allowing Newington to dispatch on the generally less expensive fuel, this dual fuel portfolio for the Station also means that fuel cost volatility is less than for a station that uses only the fuel with higher price volatility. Exhibit G.5 shows daily spot prices for natural gas at Dracut and 1% sulfur RFO at New York Harbor over the period January 2, 2006 through September 14, 2010.[18] The annualized historical volatilities of the daily prices were about 66% for natural gas delivered to the Dracut hub in northeastern Massachusetts, 35% for RFO, and 40% for the cheaper of the two daily fuel prices. The average spot prices over this period were $7.19/MMBtu for Dracut gas, $9.53/MMBtu for RFO, and $6.78/MMBtu for the cheaper fuel.

**Exhibit G.5: Historical Daily Spot Natural Gas and Residual Fuel Oil Prices**




Fuel price volatility parameters are shown in Exhibit G.6. In Exhibit G.6, LAI has derived a range of ± 1.0 standard deviation around the mean of daily prices for each year.[19] The bars represent an index of volatility, albeit an informal one.[20] Bars are presented for natural gas, residual oil, and for the lesser of the two substitutable fuels as determined

---

the ROV of Newington Station's dual fuel flexibility is more complicated than for a standard financial exchange option.

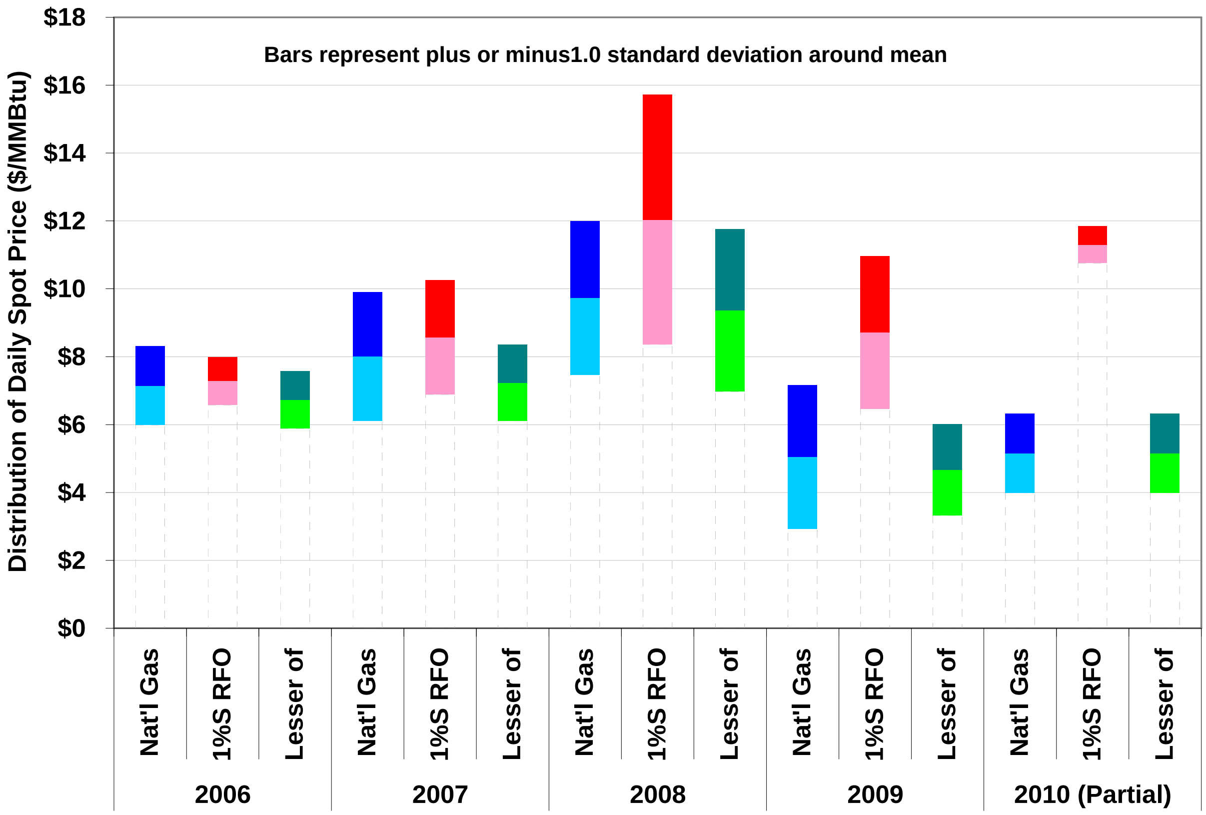
[18] Source of historic fuel prices is Bloomberg LP.

[19] Only the first eight months are included for 2010.

[20] Technically, volatility refers to relative price changes over time, and should not include predictable mean reversion and seasonal price fluctuations, such as higher winter than summer natural gas prices. Standard deviation of prices is an atemporal measure of dispersion.

each day. For 2006, when both fuels traded at about the same price on a Btu-equivalent basis, the mean "Lesser of" price is lower than the mean price of either fuel. Moreover, the span or volatility of the "Lesser of" bar is less than that of natural gas at the Dracut hub, but greater than that for oil. In 2007, natural gas prices in New England spiked during the peak heating season – the volatility of the "Lesser of" bar is substantially less than for either fuel by itself. Prices for both fuels were extremely volatile in 2008 – the "Lesser of" bar shows some reduction in mean price, relative to gas, with a comparable range over the year. The "Lesser of" bar for 2009 shows that the optionality associated with Newington's dual fuel capability allowed for the avoidance of high cost natural gas on PNGTS during cold snaps, but also accommodated the Station's access to much less costly natural gas the rest of the year. For the first eight plus months of 2010, residual oil has been priced so far above natural gas that the price parity ratio coupled with the underlying volatility has rendered the fuel choice optionality of no practical use.

**Exhibit G.6: Fuel Price Volatility and Switching/Blending Optionality**




### E.1.3. Capacity Revenue

Newington Station derives a substantial portion of its operating revenue from the ISO-NE administered capacity market. The first four years of FCA prices are known and show a positive benefit for Newington Station. After the 2013/14 capacity year, FCA prices are presently unknown, but can be reasonably forecast through the middle of the decade based on the magnitude of the existing surplus capacity, among other things. In addition to market supply-demand uncertainty, there is regulatory uncertainty associated with ISO-NE's administration of the FCM. On July 1, 2010, ISO-NE filed at FERC its Revised FCM Proposal in response to FERC's April 23rd Order. Integral to ISO-NE's proposal is the introduction of potential capacity congestion ascribable to the creation of eight load zones. New Hampshire is one of the eight load zones that could be used for capacity pricing. Under ISO-NE's proposal, all de-list bids will be allowed to set zonal prices. ISO-NE has also formulated new rules that are designed to mitigate potential market power. The revised mitigation rules result in competitive de-list bids for all resources, thereby permitting all capacity zones to be modeled in the auction, whether or not a need for the zone is identified prior to the auction.[21]

## E.2. Insurance-like Hedge Value to PSNH's Customers

The operational sources of value discussed in Section E.1 are realized on a daily and hourly basis as operational responses to daily changing energy, ancillary service, and fuel prices, and annually changing capacity prices. In addition, Newington Station provides PSNH's customers with risk reduction benefits as a physical substitute for various forms of insurance-like or financial hedge benefits. The first type of insurance-like hedge value provided by Newington Station is longer term, with infrequent decisions, while the second type is short-term, with daily decisions.

The previously-described operational and dual fuel flexibility benefits of Newington Station were discussed in terms of a risk-neutral operational policy that maximizes expected benefits, but does not consider the risk reduction benefits of continued operation of the Station. In this section, we focus on the risk reduction side of these flexibility traits, and also consider any additional value that the Station provides beyond what could be procured in the form of insurance or financial hedge contracts.

### E.2.1. Long-Term Hedge Value

On a year-by-year basis, Newington Station provides two types of real option value based on waiting for future events to unfold as well as acknowledging new information for better decision-making. Acting on new information reduces the risk of forfeiting economic benefits by prematurely retiring the Station and also preserves PSNH's ability to achieve economic benefits for its customers through new investment. Retirement is irreversible. Moreover, temporary mothballing of Newington Station in accordance with existing ISO-NE rules also results in significant cost incurrence that would be allocated to PSNH's customers. Hence, there is significant economic value to customers in postponing the decision to retire. The rational hesitation to make a retirement decision is known in ROV theory as the value of "waiting" for more information.

PSNH's customers realize capacity benefits through the sale of Newington capacity into the ISO-NE FCM. As previously mentioned, there are many uncertainties associated with ISO-

[21] Exactly how ISO-NE's proposed mitigation rules will result in competitive static and dynamic de-list bids is not presently known with any degree of confidence. Permanent de-list bids that exceed 1.25 times the cost of new entry (CONE) are subject to the review of the market monitor to assure that they are consistent with relevant going forward costs of the unit, adjusted for risk.

NE administration of the FCM under FERC jurisdiction. Uncertainty surrounding the outcome of potential regulatory changes in the FCM that would directly affect market clearing prices over the CUO study horizon provides PSNH's customers with another source of option value. The benefit of waiting for more information is tantamount to an insurance-like hedge value; importantly, there is no net cost borne by PSNH's customers if the Station's incremental revenue requirement reflects a net benefit to customers. If, on the other hand, the incremental revenue requirement represents a cost to customers in certain years, the cost borne by PSNH's customers may still provide a potential future benefit larger than the current cost merely because Newington's continued operation in part shields PSNH's customers from higher capacity costs ascribable to ISO-NE's proposed restructuring of the FCA. There are other potential uncertainties affecting the amount and timing of unit retirements across New England that likewise bear upon market clearing prices in the FCA. Hence, Newington Station provides PSNH's customers with a relatively known cost of 400 MW, thereby providing a physical asset hedge against uncertain FCA prices.

The rules for the capacity market in New England are currently in flux, thereby adding to the range of plausible capacity prices over the planning horizon, in particular, from 2016 through 2020. Based on ROV principles, this feature implies that there is a substantially larger option value currently for taking a wait-and-see decision on Newington Station's retirement than will be the case upon resolution of the rules governing modifications to the FCA at FERC. When market uncertainty is high, new investment is rationally deferred until investors can reasonably expect a satisfactory return on investment. Similarly, the decision to postpone the retirement of a generation plant can be rationalized even if immediate retirement seems warranted based on DCF analysis. There is a hedge value in waiting until a real option premium cost is surpassed before making either an investment or a retirement decision, especially when the cost of reversing a retirement decision is prohibitively expensive or not feasible.

A second type of long-term ROV relevant to the CUO analysis of Newington Station is its capital investment options for improving operational performance, extending its useful life, expanding capacity at the site, or repowering. The potential repowering of Newington Station could result in additional generation nameplate. A capital investment at Newington Station is similar to a financial call option. PSNH has a set of investment opportunities, which are options to spend capital (the "exercise" price) at some future date and acquire an asset (the project) that will deliver a less uncertain stream of future value.

The common aspect of these investment opportunities is that PSNH holds the option to invest next year or the year after, and so on for as long as PSNH owns and controls the site. When either the future costs of an investment or the net operating revenues resulting from an investment are uncertain, then there is a real option value of waiting before making the investment decision. The ability to not invest immediately or at some future fixed date is valuable because if the investment cost increases or the expected net operating revenues decrease while waiting, then PSNH can decide to further delay the decision or conclude that no investment is warranted. Alternatively, if the prospective investment appears more attractive at the next decision date, then the project is more likely to be built (exercised) at that time.

### E.2.2. Short-Term Hedge Value

On an annual ES year basis, PSNH formulates a plan for provision of capacity and energy from its own resources and from bilateral or spot market purchases, and for procurement of fuel. In this regard, Newington Station provides two types of hedge or insurance-like benefits as part of overall ES planning.

First, the previously discussed ability of Newington Station to vary its operation level and its ability to alter its fuel mix means that the Station provides a natural or physical hedge against daily fluctuating energy and fuel prices. These forms of operational flexibility allow PSNH to avoid the need to enter into bilateral energy contracts which typically have a significant risk premium, especially during the on-peak summer and winter delivery periods when the vast majority of Newington's generation is typically scheduled. Instead, PSNH can purchase fuel forward contracts, which are generally recognized as having a lower market risk premium (as a percentage of the price) than on-peak power contracts.

Second, Newington Station's operational and dual fuel flexibilities allow PSNH to diversify its financial contract positions between the energy and fuel markets, and to modify its contract positions over time in response to changing market conditions, along with changes in Newington's operation from the original ES plan. For example, if after PSNH has committed to purchase fuel for Newington Station the market price for bilateral ISO-NE energy declines such that it is economically beneficial to customers for PSNH to sell the fuel and purchase the bilateral energy, these contracts can be done in order to maximize value. PSNH can also perform the reverse type of risk mitigating trading by selling pre-purchased energy and buying fuel to run Newington. This latter strategy was used in the fall of 2008 when PSNH purchased oil for Newington to burn in January and February 2009 and unwound previously committed energy purchases for this period.

Third, PSNH has the ability to wait on making bilateral energy purchases for annual ES customer needs because PSNH has a physical "call" on the energy output of Newington. With bilateral contracting of fuel supply for Newington, the cost of producing energy from the Station is relatively fixed. Inclusion of Newington Station in the portfolio of positions for providing on-peak energy provides multiple types of contracting flexibility. The "long" Newington position provides the customer benefit of the market-timing flexibility of waiting when considering the load uncertainty related to ES rate customer migration (ingress/egress), and commodity price uncertainty.

At the weekly and daily level, there are fewer available financial market contracts available to PSNH for managing its financial exposure. In this intra-monthly timeframe, Newington Station provides a degree of risk management that is otherwise hard or expensive to obtain. On a daily basis, PSNH forecasts its hourly load and supply resource position for the following day. This process incorporates updated information on weather and load patterns, generation unit availability, hydroelectric and independent power producer generation forecasts and existing power purchases, as well as the operational status of Newington Station. The daily forecast estimates the expected residual level of energy obligation that is served by ISO-NE spot purchases rather than a known price or cost. PSNH reviews this exposure and may execute additional bilateral purchases. Typically, a portion of PSNH's energy obligation is procured in the ISO-NE RT and DA market. As PSNH's marginal cost resource, Newington Station plays a pivotal role in these daily risk management activities. Two types of special events create conditions where Newington provides infrequent but potentially substantial risk reduction benefit. One type of situation is an adverse weather condition. The other is an outage at one of PSNH's generation units.

PSNH's customers are exposed to the positively correlated weather-related risks that actual load will be higher than the expected load and that prices will be higher than expected. On a day to day or week to week basis if weather conditions occur or prices escalate in a manner that would adversely impact PSNH customer costs, Newington Station can be bid or self-scheduled into the DAM and RTM energy markets with a strategy intended to reduce or eliminate exposure to high or volatile energy prices. The DA bidding of Newington Station can also be tilted toward scheduling in the DAM at some load level. This strategy facilitates a quick response in the RTM as needed to help stabilize energy costs.

A second type of event that would cause PSNH's management to hedge the operating strategy of Newington Station more towards the RTM is when one of PSNH's other major units, Schiller or Merrimack, experiences a forced outage, exposing PSNH to its DA scheduled generation price risk in the RTM. The availability of Newington provides an alternative to procurement of outage risk insurance for the other stations.

As a physical asset, Newington Station enables these dispatch responses to help stabilize costs. Financial product or insurance product alternatives to bidding Newington Station in a risk-averse manner tend to have high risk premiums built into their pricing. Standard financial instruments, such as forwards and on-peak call options typically settle against DA rather than RT prices, and for lengthy blocks of hours, rather than for one or a few hours or peak load or outage exposure.

## E.3. Capacity Price Suppression in ISO-NE's Forward Capacity Market

If Newington Station is retired, the market price for capacity that clears through ISO-NE's FCA could rise significantly. Although Newington Station's installed capacity is small relative to the total amount of capacity procured region-wide (about 1.2%), the postulated subtraction of Newington Station from the FCM would have a disproportionately large impact on the clearing price, *all other things being the same*.

In fact, retirement of Newington Station would result in the capacity price increase over the forecast period. In the FCA, Newington Station is a price taker, not a price setter. The reason for the disproportionate price impact associated with subtraction of 400 MW from the supply mix is that Newington Station would be replaced by a new, more expensive resource. This new resource is likely to set the clearing price that might be significantly higher than the price set otherwise, depending on the slope of the supply curve in the range around the procurement target. The slope of the supply curve becomes an even more important factor in meeting the vertical demand curve used by ISO-NE to set market clearing prices under the FCM. The vertical demand curve represents a locus of points that is perfectly inelastic. Hence, when running the descending clock auction, ISO-NE's use of the vertical demand curve means that market prices are hypersensitive to relatively small changes in capacity.

ISO-NE's proposed FCM rule changes, including creation of multiple capacity zones in every FCA, are under review at FERC, and may ultimately be challenged by market participants at FERC or before the D.C. Circuit Court. Should ISO-NE prevail, LAI believes that the creation of capacity zones in accord with the existing eight load zones could ultimately leave New Hampshire potentially exposed to adverse capacity price changes resulting from relatively small changes in the amount of generation and/or transmission capacity available to serve New Hampshire load. Continued inclusion of Newington Station in the supply stack available in New Hampshire, in particular, and New England, in general, places significant downward pressure on FCA clearing prices regardless of FERC's decision on ISO-NE's Revised FCM Proposal.

## E.4. Energy Security and Diversity for New Hampshire

Newington Station is located in the Seacoast Area which contains approximately a quarter of the total electric demand in New Hampshire. The Seacoast Area relies on local generation to reliably meet peak customer demands.[22] Newington Station can be called upon to provide voltage support to the system, and ISO-NE often calls for dispatch of the unit when there is an immediate or forecasted need for electric system grid stability or reserve. Newington Station also has the flexibility and ability to operate on residual oil and provide power to the electric grid when natural gas is curtailed for any reason, thereby providing much needed fuel diversity for the area. Because of these capabilities, Newington Station provides a valuable contribution to the energy security and reliability of the New Hampshire system and the New England grid as a whole.

Energy security for New Hampshire is enhanced by having more generation units and having a diverse mix of generation technologies and fuel sources. Going forward, the annually increasing renewable portfolio standard (RPS) requirements of New Hampshire and other New England states is expected to result in a growing number of wind farms and other renewable energy resources. Wind and solar energy, while providing clean energy benefits, are variable or intermittent energy technologies, requiring load-following energy generation from other local resources. Newington Station is well-situated and has the operational flexibility to provide AGC and a portion of the load-following and regulation service needed by ISO-NE to integrate variable energy resources (VERs) in and around New Hampshire.

Continued operation of Newington Station provides jobs for station operation and maintenance. The salaries and wages provided by the direct jobs are largely spent in the local New Hampshire economy. A portion of Newington Station expenditures for materials, supplies, and services is also spent in New Hampshire. Together, the direct expenditures for labor, materials, and services support the existence of other local New Hampshire employment and economic output across the range of industries. These indirect and induced expenditures are often quantified with the use of a regional economic model. These regional models typically indicate that the total impact of direct expenditures for labor and materials/services for operation of a generation station have a multiplier effect in the range of 1.5 to 3.0.

[22] See ISO-NE, *2009 Regional System Plan*, p. 131; ISO-NE, *RTEP04 Technical Report*, pp. 224-227.

## E.5. Operating Advantages in the Regional System

Newington Station provides several specialized types of operating benefits to the regional electric system, given its operating capabilities and location within the regional transmission and fuel supply systems. This section briefly describes the regional support benefits provided by Newington Station's capabilities:

- Electric delivery system support
- Transmission system contingency operations
- Oil backup during gas curtailments
- Load-following of variable energy resources.

**Electric delivery system support**. Newington Station is strategically situated for providing direct support services to the 345 kV system and indirect support services to the 115 kV system. It is also in close grid proximity to the Seabrook Station. There are future plans to install a 345/115 kV autotransformer near Newington and Schiller substations which will make them electrically closer to each other. Newington Station provides benefits and options to the transmission system during light and heavy load periods. For example, during light load times when Seabrook Station is offline, Newington Station can be called on to provide voltage support to the 345 kV system. Newington Station is beneficial to the regional system when major units trip offline because of the Station's quick start-up time relative to the cohort group of steam turbine generators in the region. ISO-NE frequently calls for an immediate start or next morning dispatch of the unit when there is an immediate or forecasted need for generation capacity or reserve. Newington Station's low minimum startup load level (60 MW) allows the Station to be operated at 60 MW to support the system, thereby providing 340 MW of spinning reserve.

**Transmission System Contingency Operations**. Newington Station is equipped with a Special Protection System (SPS) under the control of ISO-NE. The SPS is a device that allows Newington Station to operate in a condition when the 345 kV 326 line from Scobie to Sandy Pond could become overloaded due to the loss of another transmission line in the area. Newington Station's SPS is one of the few allowed by ISO-NE. Without the SPS, Newington Station would not be able to maintain or increase its generation under certain line loading conditions.

**Oil backup for gas curtailments**. Approximately 8,800 MW of summer rated generating plants in New England operate on natural gas only.[23] The majority of these generating plants do not have primary entitlements to firm pipeline delivery capacity, the majority of which is reserved by gas utilities to ensure firm service obligations throughout the heating season, November through March. During cold snaps or other conditions when pipelines experience deliverability constraints, gas supply may not be available to generators in New England. Newington Station has the flexibility and ability to operate on RFO when natural gas is curtailed for any reason. Over the last decade, ISO-NE's heavy reliance on natural gas has created a situation where upsets in natural gas supply or deliverability within New England's borders can adversely impact electricity reliability and cost. Fuel diversity is therefore an integral component of both grid reliability and price value for customers.

[23] Based on September 2010 seasonal claimed capability report from ISO-NE.

**Load-following of variable energy resources**. Newington's wide operating range and relatively fast start time and ramping time allows it to provide load-following services to back up the variable and less reliable energy generation from the increasing capacity of VERs, such as wind and solar. VERs have variable and/or intermittent energy output due to their sources of fuel. According to the NHPUC, "units such as Newington mesh extremely well with the generation expansion plan envisioned by the region. The New England region is leaning towards increased energy production from renewable resources, namely wind. Wind power can fluctuate widely within a short period of time. Fast reaction resources such as Newington have value in integrating those renewable resources into the power grid. Newington also has a dual fuel capability which must be factored into the evaluation." [24]

## F. Quantitative Analysis of the Economic Benefits of Newington Station

In this section, LAI conducts quantitative analysis of the main economic benefits related to continued operation of Newington Station under market price uncertainty. Quantification of Newington Station's economic value requires a forecast of wholesale market prices in New England. The cost of market-based energy reflects wholesale power cost in ISO-NE's DAM and RTM. The value of capacity is consistent with ISO-NE's FCM with Newington in operation. Following PSNH's approach on developing forecasted market energy prices, LAI has calibrated wholesale energy prices over the planning period, 2011 through 2020, using an approach that is based on NYMEX forward prices for energy at MassHub through 2015, and then based on NYMEX natural gas futures. Fuel prices at the Station are based on NYMEX futures for RFO as well as for natural gas.

Energy net operating revenues that reflect the Station's operating and fuel-blending flexibilities are simulated using the ROV framework of allowing for daily and hourly commitment and dispatch decisions. Capacity prices under the FCA are also simulated probabilistically, but not using the ROV method. Importantly, capacity prices are assumed to remain independent of the fuel and energy price paths.[25] This means that the independent mixture of energy net revenues and capacity revenues will have a smaller probability distribution than either output revenue stream alone.

A rigorous market price simulation and dispatch model simulates Newington Station across 250 uncertain future scenarios for key operating inputs and outputs. The starting point for the ROV analysis is a set of expected price forecasts for oil, natural gas, and emission allowances, and both DAM and RTM energy prices on the product side. As discussed in Section F.2.1, capacity prices are also represented for three discrete capacity price projections that are formulated to account for the uncertainty associated with both market dynamics and ISO-NE's proposed structural changes to the existing FCA. The 250 annual energy net revenue scenarios were sampled with the three discrete capacity price scenarios many times. Where possible, the forecasts are based on available market forward curves.

---

[24] See direct testimony of Michael D. Cannata, Jr., NHPUC Staff Consultant, Docket DE 09-091 (2008 Energy Service and Stranded Cost Recovery Charge Reconciliation) on October 19, 2009.
[25] Beginning at the need date, capacity prices converge to Net CONE, which reflects the net margin associated with dispatch of the peaker.

Current and recent historical market heat rates and historical hourly price shapes were used to develop the energy hourly price projections.

To derive the value of Newington Station, LAI constructed a model that uses a mixture of probabilistic scenario analysis to simulate future capacity price scenarios, and more detailed Monte Carlo chronological analysis using daily correlated random draws to simulate oil and natural gas prices, DAM and RTM energy prices, and unit outages. Monte Carlo analysis uses computer-generated random numbers to sample from user-defined multivariate probability distributions, accounting for correlations, to simulate uncertain events or processes that unfold over time. The ROV aspect of the model is that it runs chronologically and simulates daily DA scheduling and hourly RT scheduling and fuel blending/switching decisions. The LAI model uses equal weights for each simulated scenario or random market prices and unit outages. The model simulates the two primary components of Newington Station's flexibility value:

- Ability to start relatively quickly and ramp-up or down within its wide operating capacity range, allowing the Station to bid efficiently into both the DAM and RTM.

- Ability to switch fuels on-the-fly or optimize the blend of natural gas and residual oil, accounting for the lower maximum operating capabilities at the two natural gas-combustion blend thresholds.

## F.1. Newington Station's Prospective Going Forward Costs

The CUO analysis only includes incremental costs that would be incurred going forward as the Station continued to operate. Historical costs that have been incurred and are anticipated to be recovered whether or not the unit continues operating are not included in the analysis. Therefore, the depreciation expenses for previous capital additions are not included in the CUO analysis, but new capital additions are included.

PSNH projects $500,000 per year of additional capital expenditures in order to maintain the efficiency and reliability of Newington Station. The $500,000 annual expenditure represents an average or steady-state amount, while actual expenditures would likely vary between years. The depreciation schedule amortizes the capital expenditures by the number of years remaining in the ten-year analysis period. At the extremes, 10% of 2011 capital expenditures are depreciated each year, while 100% of 2020 capital expenditures are depreciated in that year. All capital expenditures are fully depreciated by the horizon of the analysis period, ensuring that all going-forward capital expenditures are charged to Newington Station's going forward costs.

Exhibit G.7 shows the expected fixed expenses portion of the going forward revenue requirements for Newington Station. These fixed costs form the foundation of the CUO analysis. Fuel and fuel-related O&M costs reflect the expected dispatch regime of the plant over the forecast period based on LAI's simulation analysis. The revenues derived from capacity, energy and ancillary sales are netted against the going forward revenue requirements of Newington Station shown in Exhibit G.7.

## Exhibit G.7: Estimated Going Forward Fixed Portion of Annual Revenue Requirements

| | Present Value EOY 2010 | Calendar Year 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Expenses ($000)** | | | | | | | | | | | |
| Non-Fuel O&M with Indirects | | | | | | | | | | | |
| Other than Emission Allowances | $50,558 | $7,498 | $7,706 | $7,920 | $8,139 | $8,366 | $8,600 | $8,841 | $9,089 | $9,343 | $9,605 |
| Emission Allowances | | **Varies with simulated output and fuel mix** | | | | | | | | | |
| Total O&M Expense | | | | | | | | | | | |
| Fuel and Fuel Related O&M | | **Varies with simulated output, fuel mix, and fuel prices** | | | | | | | | | |
| Property Tax | $7,920 | $958 | $1,034 | $1,117 | $1,206 | $1,303 | $1,407 | $1,520 | $1,641 | $1,773 | $1,914 |
| Depreciation Expense | $2,406 | $50 | $106 | $168 | $240 | $323 | $423 | $548 | $715 | $965 | $1,465 |
| **Total Expenses** | | | | | | | | | | | |
| **Rate Base ($000)** | | | | | | | | | | | |
| Incremental Gross Plant Value | | $500 | $1,000 | $1,500 | $2,000 | $2,500 | $3,000 | $3,500 | $4,000 | $4,500 | $5,000 |
| Incremental Accum. Depreciation | | $50 | $156 | $324 | $563 | $886 | $1,309 | $1,857 | $2,571 | $3,536 | $5,000 |
| Net Plant Value | | $450 | $844 | $1,176 | $1,437 | $1,614 | $1,691 | $1,643 | $1,429 | $964 | ($0) |
| Working Capital | | $925 | $925 | $925 | $925 | $925 | $925 | $925 | $925 | $925 | $925 |
| Accumulated Deferred Taxes | | $12 | $32 | $64 | $112 | $181 | $279 | $417 | $613 | $898 | $1,372 |
| Fuel Inventory (year end) | | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 |
| NOx, SO2, CO2 Allowance Inventory | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Material & Supply Inventory | | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 |
| **Total Rate Base** | | $13,887 | $14,301 | $14,665 | $14,973 | $15,219 | $15,395 | $15,485 | $15,466 | $15,287 | $14,796 |
| *Average Return on Rate Base* | | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* |
| **Return on Rate Base ($000)** | **$9,990** | **$1,540** | **$1,586** | **$1,626** | **$1,660** | **$1,688** | **$1,707** | **$1,717** | **$1,715** | **$1,695** | **$1,641** |
| **Expenses Plus Return on Rate Base** | | | | | | | | | | | |
| **Revenues ($000)** | | | | | | | | | | | |
| Energy | | **Varies with simulated output and energy prices** | | | | | | | | | |
| Capacity | | $17,250 | $13,343 | $12,121 | **Varies with capacity prices** | | | | | | |
| Ancillary | $1,214 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 |
| 10 MW Unitil Entitlement | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Revenue** | | | | | | | | | | | |
| **NET REVENUE REQUIREMENT** | | | | | | | | | | | |

## F.2. Modeling Method and Data for Price Simulation

This section first describes the modeling techniques for simulating uncertain future fuel, emission, and product prices, and for simulating unit economic dispatch. The general method includes the following procedures:

- Forward market price curves for natural gas, RFO, 2FO, emission allowance ($SO_2$, $NO_x$, $CO_2$), energy, and capacity prices were relied on to extent available.
- Three discrete capacity price forecasts, commencing with Delivery Year 2014/15, and their probabilities were formulated.
- Prices for RFO and 2FO beyond their forward curve horizons were based on their statistical relationship to forward WTI crude oil prices through its 2018 forward horizon, and extrapolated thereafter.
- Short-term and long-term stochastic parameters for natural gas, RFO, and 2FO were statistically estimated from historical spot price data.
- Monthly on-peak and off-peak forward prices beyond the MassHub forward curve were extrapolated based on market heat rates over the past seven years.
- Hourly price shapes for monthly on-peak and off-peak forward energy prices were calculated using the past seven years of hourly energy prices at Newington Station.
- Newington node DA energy prices were calculated from MassHub prices based on the last seven years of hourly location basis spreads.
- Elasticities for the change in Newington Station DA energy prices for a given change in Dracut natural gas price were statistically estimated based on the past seven years of DAM hourly energy price data.
- Newington node RT energy prices were calculated based on the historical time spread between DA and RT prices at that node.
- Emission allowance prices were extrapolated beyond their market forward curve horizons.

### F.2.1. Capacity Price Scenarios under ISO-NE's Forward Capacity Market

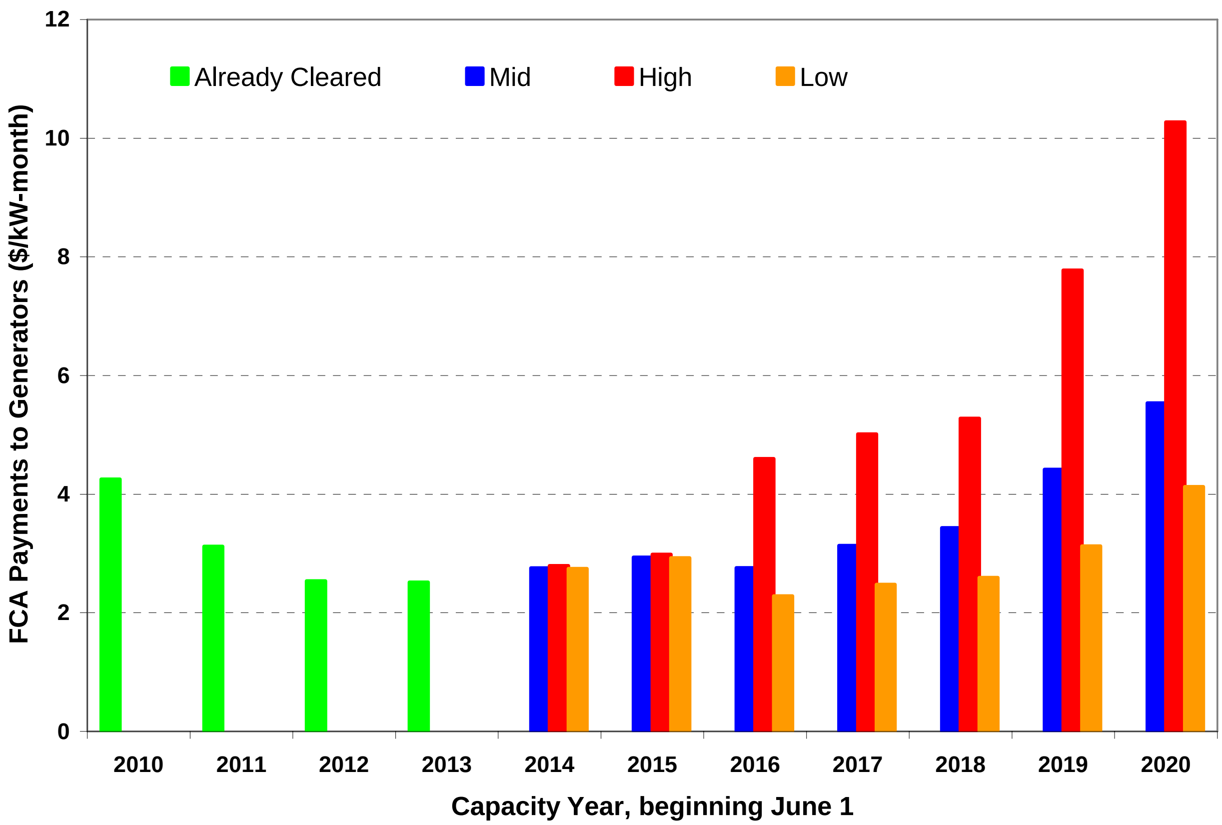
Uncertainty surrounding the future price of capacity is an integral part of this CUO analysis, but the real option values of potential future retirement or repowering are not an explicit part of the valuation of Newington Station. This is because LAI has assumed that Newington Station continues to operate over the study horizon, 2011 through 2020. Hence, no optionality associated with the capacity of Newington Station was modeled.

Nevertheless, market rules affecting capacity prices in New England are presently under review by FERC and can expose PSNH's customers to adverse economic outcomes associated with the replacement of Newington's capacity at market prices over the study horizon. Fundamental changes to the structure of the FCM are likely to occur in 2010 or 2011, but not later than 2012. Under existing market conditions, there is an excess of capacity relative to the Installed Capacity Requirement (ICR), thereby supporting a low to moderate capacity price forecast over the planning horizon, 2011 through 2020. This is reflected in the "Mid Case" forecast. Although ISO-NE does not need new capacity on a region-wide basis, substantial new resource additions are nevertheless anticipated in association with New England's RPS, as well as the availability of incremental DR. Moreover, FERC in its April 23, 2010 Order reiterated the need for locational capacity prices, thereby supporting the introduction of more "granular" capacity prices to reflect the potential for capacity congestion across eight load zones in New England. New Hampshire, like Vermont and Maine, will be a separate New England capacity zone in the FCA if FERC approves ISO-NE's FCM redesign filing. No effort has been made in this CUO study to forecast capacity prices for New Hampshire as a specific capacity zone.

Removal of the existing capacity price floor after Delivery Year 2015/16 is also incorporated in LAI's capacity price scenarios. The absence of the pivotal supplier test coupled with the implementation of potentially ill-defined so-called Out of Market (OOM) new mitigation rules in the revised FCM proposal exposes customers in New Hampshire to an increased economic burden associated with the cost of replacement capacity if Newington Station is retired. Under the revised Alternative Price Rule (APR), ISO-NE would re-price the new capacity offers to a higher level if it believes that the offers are inconsistently lower than the in-market offers would be, would rebuild the supply curve, and, as a result, the actual capacity payment rate to all existing resources would be set administratively at a level higher than the FCA clearing price. From PSNH's customers' vantage point, this adverse exposure would begin in FCA #6 for Delivery Year 2015/16 and would continue through the remainder of the planning horizon.

Three capacity price scenarios have been incorporated in the financial analysis. The capacity price scenarios are shown in Exhibit G.8.

**Exhibit G.8: Capacity Price Forecasts by Scenario**



Under the Mid Case, we projected capacity surplus positions based on a regional load-resource analysis that used load growth from the 2009 CELT report and capacity additions and retirements consistent with growing RPS and environmental control requirements. Generally consistent with the Connecticut IRP, we assumed retirement of approximately 2,100 MW of capacity over the period 2014-2016 due to increasingly strict environmental standards.[26] Additionally, the capacity forecast calls for the elimination of imports of capacity from New York gradually over the planning horizon.[27]

Under the High Case, we have assumed that capacity prices escalate substantially in the last three years of the study horizon, 2018 through 2020, to account for the possible restructuring of the FCA under ISO-NE's Revised FCM Proposal, among other things. Arguably, the run-up in capacity prices under the revised APR may occur two to three years earlier, but LAI did not contemplate this scenario. In formulating the High Case, LAI has assumed that capacity prices converge on the annuitized cost of a GE 7FA Frame peaking unit by 2022, two years beyond the end date of the planning horizon.[28] The escalation in capacity prices begins in 2018, corresponding to FCA # 8. In LAI's view, this assumption represents a reasonable proxy for the engineering economic analysis to be conducted by ISO-NE's Internal Market Monitor (IMM) whenever new or carried-forward OOM capacity clears in the FCA. The new APR proposed by ISO-NE in the Revised FCM Proposal is designed to correct for the presumed price suppression effect of OOM resources on the FCA clearing price. However, the actual capacity prices set by the APR application will greatly depend on the amount of the OOM offered, the methodology – yet to be defined by ISO-NE – for calculation of the re-priced OOM offers, and the shape of the supply curve. To account for the uncertainty surrounding the structural components of ISO-NE's proposal, we have increased the total attrition assumption by 500 MW. The increased attrition assumption is intended to represent a conservative view about the amount of existing capacity that may be unwilling to spend substantial CapEx to meet stricter environmental requirements. In actuality, the increased attrition may be significantly higher.

In the Low Case, imports are curtailed more slowly. In the Low Case, 200 MW of imports persist over the forecast period. Additionally, the postulated retirement of the West Springfield facility is delayed one year, and a total of 200 MW of DR is added to the supply mix over the forecast period, thereby reducing capacity prices. The low case represents the floor for plausible price outcomes given the risk factors associated with environmental regulations and ISO-NE inspired market rule changes mentioned above.

In conducting the simulation analysis, it is necessary to weight the probability of occurrence of each of the discrete capacity price forecasts. LAI has assumed that the Mid

[26] LAI projects the retirement of West Springfield 3, Cleary 8, Yarmouth 1-4, Bridgeport Harbor 2, Middletown 3, Montville 6, and Norwalk Harbor 1-2 due to regulations that will require plants to achieve significant reductions in $NO_x$ emission rates. Because these plants have low capacity factors and generally poor economic outlooks overall, we believe that their owners will opt for retirement by 2016 rather than commit to the capital expenditure associated with SCR installation.
[27] While the 2010 CELT report is now available, we believe that the projected surplus capacity would not differ much from our prior study.
[28] Net CONE is based on the 2009/2010 tariff reference value of the NYISO reference unit for Rest of State.

Case has a 50% chance of occurrence, the High Case 30%, and the Low Case 20%. Hence, in 7 of 10 draws, capacity prices reflect the projected values in the Mid Case or Low Case. In 3 of 10 draw, capacity prices reflect the projected values in the High Case, which is materially different from the values encompassed in the Mid Case or Low Case starting in 2015. A capacity price scenario for all years is randomly drawn once at the start of each simulation.

### F.2.2. Stochastic Fuel Price Scenarios

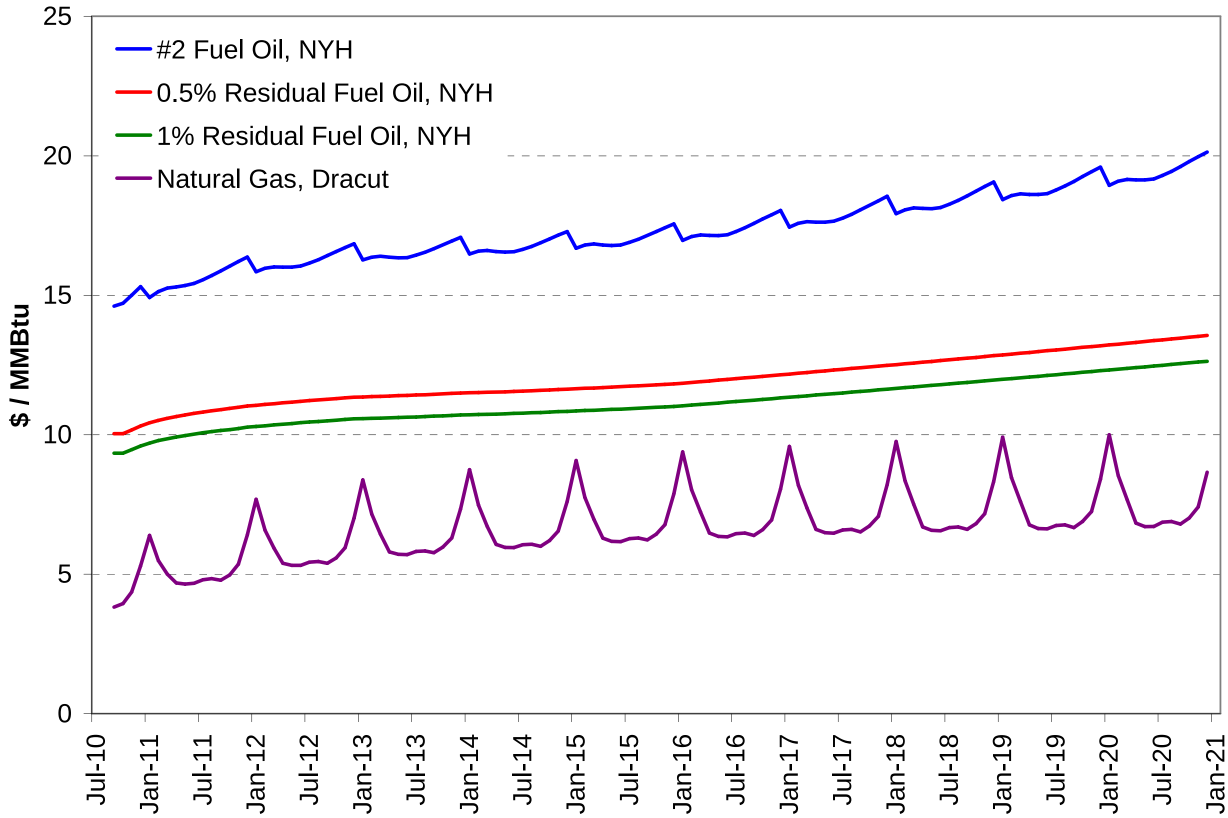
Prices for the three fuel types available for use by Newington Station were simulated stochastically using Monte Carlo simulation. The fuel commodities and pricing points are natural gas at Dracut,[29] and two oil products, 1% or 0.5% sulfur RFO and 2FO at New York Harbor. RFO with 1% S was used through 2017, after which the price reflects higher-priced 0.5% RFO. NYMEX forward market price curves on August 27, 2010 were used until December 2020 in the case of Henry Hub natural gas, and the last available month for RFO and 2FO. For other locations and longer-term dates, historical basis methods were used to estimate forward prices.[30] Forward prices at Dracut were calculated based on the historical monthly average ratio of Dracut over Henry Hub spot prices for the past seven years. Prices for RFO and 2FO beyond their forward curve horizons were based on their historical monthly average ratio to forward WTI crude oil prices through its 2018 forward horizon, and extrapolated thereafter. Exhibit G.9 shows the monthly forward price curves used as the expected price forecasts.

---

[29] The Dracut hub in northeastern Massachusetts reflects the value of natural gas delivered to northern New England, *i.e.,* Tennessee Zone 6-NE.

[30] Strictly, the basis-derived forecast prices are not “forward” prices, which are known market prices for future delivery at a specified location.

**Exhibit G.9: Forward Monthly Fuel Prices**

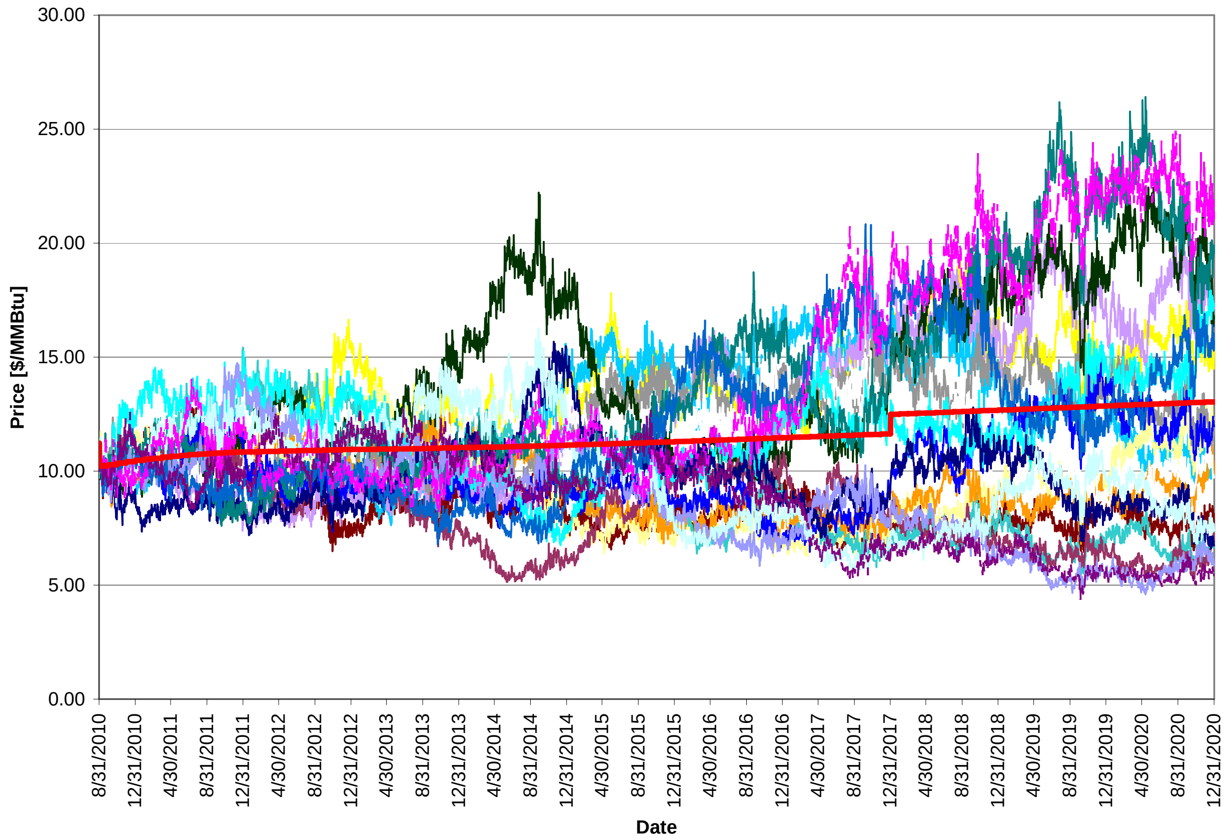



Stochastic simulation of fuel prices was done in a manner that keeps the mean or average daily spot price across the set of stochastic scenarios equal to the forward price. Short-term (ST) and long-term (LT) volatility rates, mean reversion rates, and correlations for natural gas, RFO, and 2FO prices were statistically estimated from historical data. Daily spot prices of natural gas at Dracut, and oil prices at New York Harbor from March 2003 through July 2010 were used for the estimation of ST stochastic parameters. LT volatility and correlation rates were estimated for the same fuels using average annual prices for 1978 to 2009, obtained from the EIA's *Monthly Energy Review*.

Simulation of correlated natural gas, RFO, and 2FO spot prices at the daily level used a two-factor (ST and LT) mean-reverting Monte Carlo model. The ST factor simulates temporary, mean-reverting price fluctuations due, for example, to weather and market supply-demand imbalances. The LT factor simulates the cumulative uncertainty range that widens over time, producing a growing cone of uncertainty.

Because current forward prices for RFO throughout the ten-year simulation period are higher than forward natural gas prices, natural gas will generally be the less expensive fuel in the set of simulated price scenarios. But for varying durations in individual scenarios, RFO prices became less expensive than gas prices. An example of the Monte Carlo price simulation process is shown in Exhibit G.10 for RFO prices.

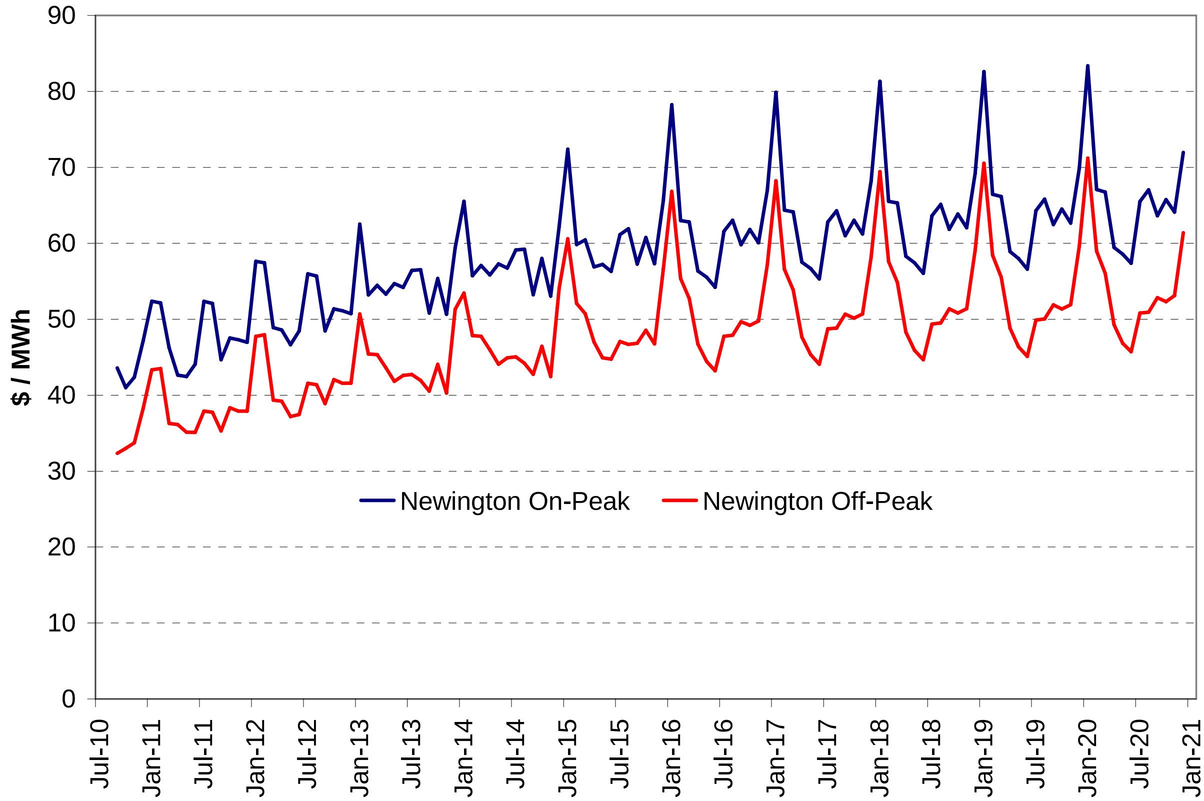
**Exhibit G.10: Example of 20 RFO Price Paths and Expected Prices**




### F.2.3. Stochastic Energy Price Scenarios

Hourly stochastic DA and RT prices at the Newington node were simulated with a four step procedure. First, monthly and strip (bi-monthly to annual) forward on-peak and off-peak prices at the Massachusetts Hub (MassHub) on August 27, 2010 were used. Second, historical hourly spot price ratios of the Newington node to the MassHub node prices were used to shape the bi-monthly to annual strip forward prices into monthly on-peak and off-peak prices at the Newington node. Third, the Newington node monthly on-peak and off-peak forward prices for the period beyond the end of the MassHub node forwards in 2015 were estimated based on the historical market heat rate relationship between Dracut natural gas spot prices and Newington node hourly energy spot prices. Fourth, expected hourly DA prices at Newington node were calculated based on the average hourly DA price shape for a typical week of each month. For the seven historical years, about 28 daily observations are available for each month's typical week hourly shape. The resulting forward monthly DA on-peak and off-peak prices are shown in Exhibit G.11.

**Exhibit G.11: Newington Forward Monthly On-Peak and Off-Peak Prices**




The hourly forward prices are the expected values for the stochastic simulation of hourly DA and RT prices. Stochastic DA and RT energy prices were simulated using the following procedure. First, historical DA energy price to natural gas price elasticities (roughly the percent change in energy price for a 1% change in gas price) were statistically estimated for three monthly time-of-use blocks (weekday on-peak hours, weekend daytime hours, and night hours) based on seven years of spot Dracut gas and Newington node hourly DA prices. Second, a stochastic energy price index for each monthly TOU block is calculated relative to the expected value for the block based on the ratio of the stochastic Dracut gas price to its expected (forward) price. Third, a random draw of an historical week of DA and RT energy price hourly shapes from the seven years of available weeks for the simulated month is taken at the start of each simulated week. Finally, the stochastic hourly DA and RT energy prices are calculated as the product of the respective randomly drawn hourly shape factors and the ratio of the stochastic block index price to the average forward price for that block.[31]

[31] This method conservatively maintains relatively constant (somewhat random) market heat rates to maintain reasonable energy price to fuel price spreads across the simulated paths. The random simulation of historical price shapes across the hours within each day's TOU block maintains actual historical price ratios between the hours and between DA and RT energy prices.

## F.3. Modeling Method for Dispatch Simulation

To perform the ROV analysis, a dispatch simulation model was developed that accounts for Newington's chronological constraints, fuel-blending constraints, and ability to dispatch in the RTM as well as the DAM. The dispatch model represented the multiple operating states with respect to natural gas combustion constraints on the fuel mix, the heat rate curve, cold and warm start times and fuel use, the $NO_x$ emissions curve, minimum up and down times, and ramping rates. The model is run with the set of stochastic price paths, and also simulates random forced outages. Newington's commitment and dispatch is simulated with the objective of maximizing its expected net operating revenue (equivalent to minimizing the expected cost to customers). The simulation model dispatches the Station against ISO-NE spot market prices. The dispatch simulation model does not use perfect foresight to "see" RTM prices when bidding into the DAM, and it does not see the onset of a forced outage. By separately dispatching any available capacity against RTM prices, the model allows some additional gross margin to be realized. Net commitment period cost or uplift revenues and expenses were not modeled. Prospective Newington Station fixed O&M costs, including additional capital expenditures to ensure plant availability and efficiency, were not treated as an uncertainty factor.

Results by simulation path are cumulated over the years of the study period into a NPV for that path. After all the stochastic paths have been simulated, the expected values and probability distributions of annual values and of the NPV are calculated for reporting in tabular or graphical form. Each scenario has the same weight, so the expected value is the simple average or mean value across scenarios.

## F.4. Asset Value Simulation Analysis Results

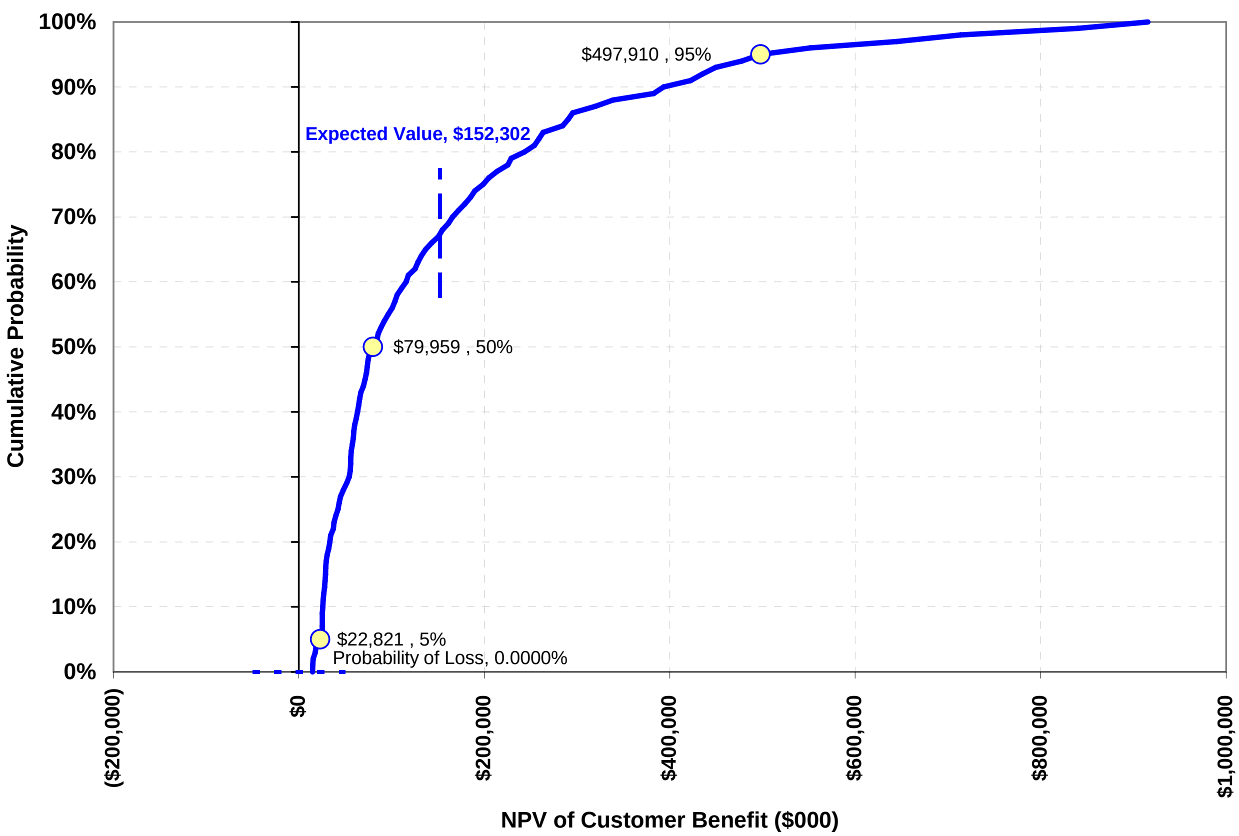
The results of the probabilistic and ROV simulation analysis are presented in the following table and set of graphs. Exhibit G.12 presents the expected annual values of incremental revenue requirements (negative value is customer benefit) for 2011 through 2020 and the NPV of incremental revenue requirements at the end of 2010. The expected values are the equally-weighted average values across the set of simulated scenarios. Incremental revenue requirements for continued operation of Newington Station are negative in every year, indicating that the Station provides value to customers. The expected NPV of customer benefits is over $152 million. Exhibit G.12 shows the same expense and revenue line items as the historical revenue requirements table, Exhibit G.1, in Section D.1. Notice that fuel expenses and energy revenues are fairly uniform over the ten-year simulation period and similar in magnitude as the average of the last five years, shown in Exhibit G.1.

## Exhibit G.12: Expected Values of Incremental Revenue Requirements

| | Present Value EOY 2010 | | Calendar Year 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Expenses ($000)** | | | | | | | | | | | | |
| Non-Fuel O&M with Indirects | | | | | | | | | | | | |
| Other than Emission Allowances | $57,236 | | $7,498 | $7,706 | $7,920 | $8,139 | $8,366 | $8,600 | $8,841 | $9,089 | $9,343 | $9,605 |
| Emission Allowances | $5,455 | | $737 | $649 | $700 | $804 | $796 | $801 | $837 | $910 | $979 | $965 |
| Total O&M Expense | $62,691 | | $8,235 | $8,355 | $8,620 | $8,943 | $9,162 | $9,401 | $9,678 | $9,998 | $10,322 | $10,569 |
| Fuel and Fuel Related O&M | $182,808 | | $29,143 | $26,072 | $26,648 | $28,562 | $26,965 | $25,143 | $24,769 | $25,696 | $27,013 | $25,775 |
| Property Tax | $9,057 | | $958 | $1,034 | $1,117 | $1,206 | $1,303 | $1,407 | $1,520 | $1,641 | $1,773 | $1,914 |
| Depreciation Expense | $2,879 | | $50 | $106 | $168 | $240 | $323 | $423 | $548 | $715 | $965 | $1,465 |
| **Total Expenses** | **$257,435** | | **$38,385** | **$35,567** | **$36,553** | **$38,950** | **$37,752** | **$36,374** | **$36,514** | **$38,050** | **$40,071** | **$39,723** |
| **Rate Base ($000)** | | | | | | | | | | | | |
| Incremental Gross Plant Value | | | $500 | $1,000 | $1,500 | $2,000 | $2,500 | $3,000 | $3,500 | $4,000 | $4,500 | $5,000 |
| Incremental Accum. Depreciation | | | $50 | $156 | $324 | $563 | $886 | $1,309 | $1,857 | $2,571 | $3,536 | $5,000 |
| Net Plant Value | | | $450 | $844 | $1,176 | $1,437 | $1,614 | $1,691 | $1,643 | $1,429 | $964 | ($0) |
| Working Capital | | | $925 | $925 | $925 | $925 | $925 | $925 | $925 | $925 | $925 | $925 |
| Accumulated Deferred Taxes | | | $12 | $32 | $64 | $112 | $181 | $279 | $417 | $613 | $898 | $1,372 |
| Fuel Inventory (year end) | | | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 |
| NOx, SO2, CO2 Allowance Inventory | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Material & Supply Inventory | | | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 | $2,500 |
| **Total Rate Base** | | | $13,887 | $14,301 | $14,665 | $14,973 | $15,219 | $15,395 | $15,485 | $15,466 | $15,287 | $14,796 |
| *Average Return on Rate Base* | | | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* | *11.09%* |
| **Return on Rate Base ($000)** | **$11,271** | | **$1,540** | **$1,586** | **$1,626** | **$1,660** | **$1,688** | **$1,707** | **$1,717** | **$1,715** | **$1,695** | **$1,641** |
| **Expenses Plus Return on Rate Base** | **$268,705** | | **$39,925** | **$37,152** | **$38,179** | **$40,610** | **$39,440** | **$38,081** | **$38,232** | **$39,765** | **$41,767** | **$41,364** |
| **Revenues ($000)** | | | | | | | | | | | | |
| Energy | $308,435 | | $45,636 | $41,347 | $42,894 | $47,691 | $45,326 | $43,934 | $44,399 | $46,564 | $48,563 | $47,313 |
| Capacity | $111,205 | | $17,250 | $13,343 | $12,121 | $12,779 | $13,791 | $14,903 | $16,420 | $17,830 | $22,106 | $29,026 |
| Ancillary | $1,367 | | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 |
| 10 MW Unitil Entitlement | $0 | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Revenue** | **$421,007** | | **$63,086** | **$54,890** | **$55,214** | **$60,670** | **$59,317** | **$59,037** | **$61,019** | **$64,594** | **$70,868** | **$76,539** |
| **NET REVENUE REQUIREMENT** | **($152,302)** | | **($23,161)** | **($17,738)** | **($17,036)** | **($20,059)** | **($19,877)** | **($20,956)** | **($22,787)** | **($24,829)** | **($29,102)** | **($35,175)** |

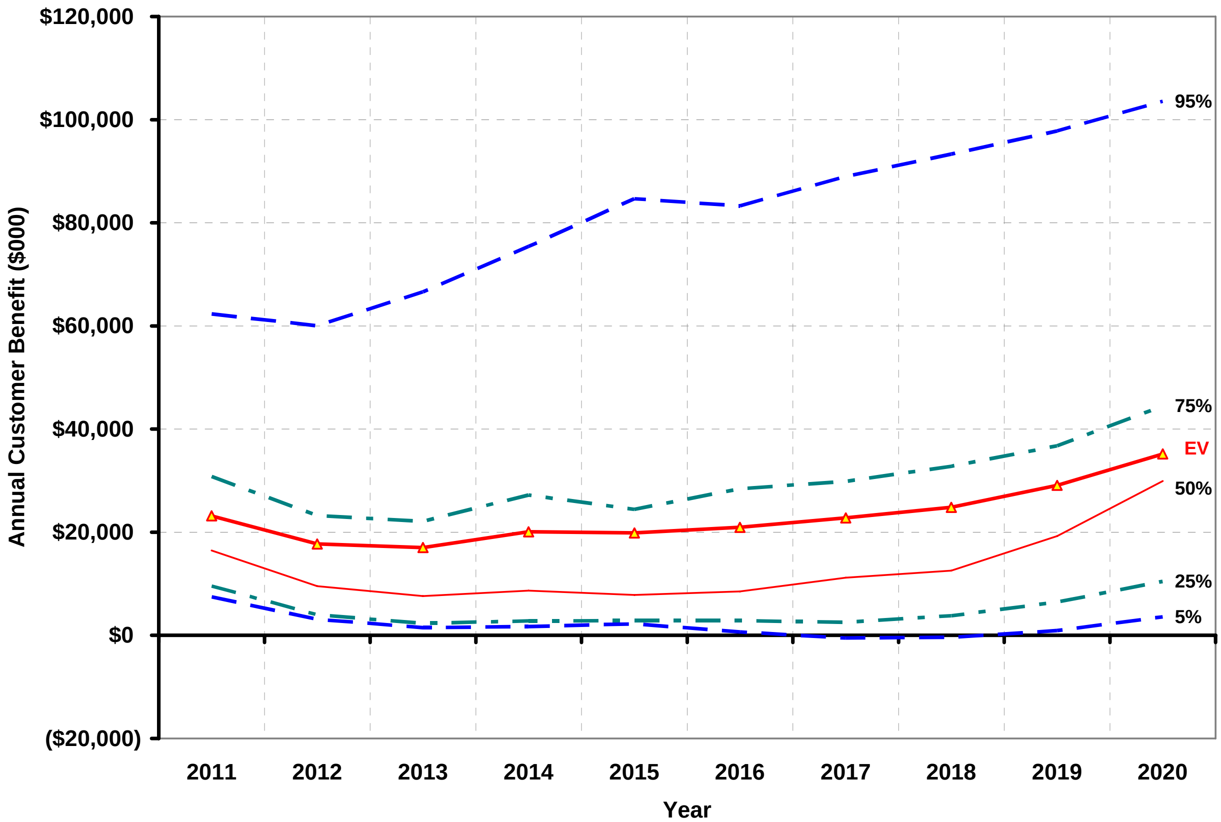
Most of the expense items have the same values in each stochastic scenario. It is therefore convenient to examine the entire probability distribution of customer benefits in the form of a cumulative density function graph, shown in Exhibit G.13. Customer benefits are defined as a reduction in incremental revenue requirements. The shape of the curve allows inspection of the NPV of customer benefits associated with a given probability level. The expected NPV dashed line on the graph corresponds to the expected NPV benefit of a reduction in incremental revenue requirements in Exhibit G.12 of $152 million. Importantly, the distribution indicates that none of the simulated scenarios results in a negative customer benefits NPV outcome. The median NPV of $80 million is substantially less than the mean or expected NPV, indicating significant right skew in the distribution. In other words, more of the equally probable scenarios have outcomes below than above the expected NPV.

**Exhibit G.13: Cumulative Distribution of NPV of Customer Benefits**



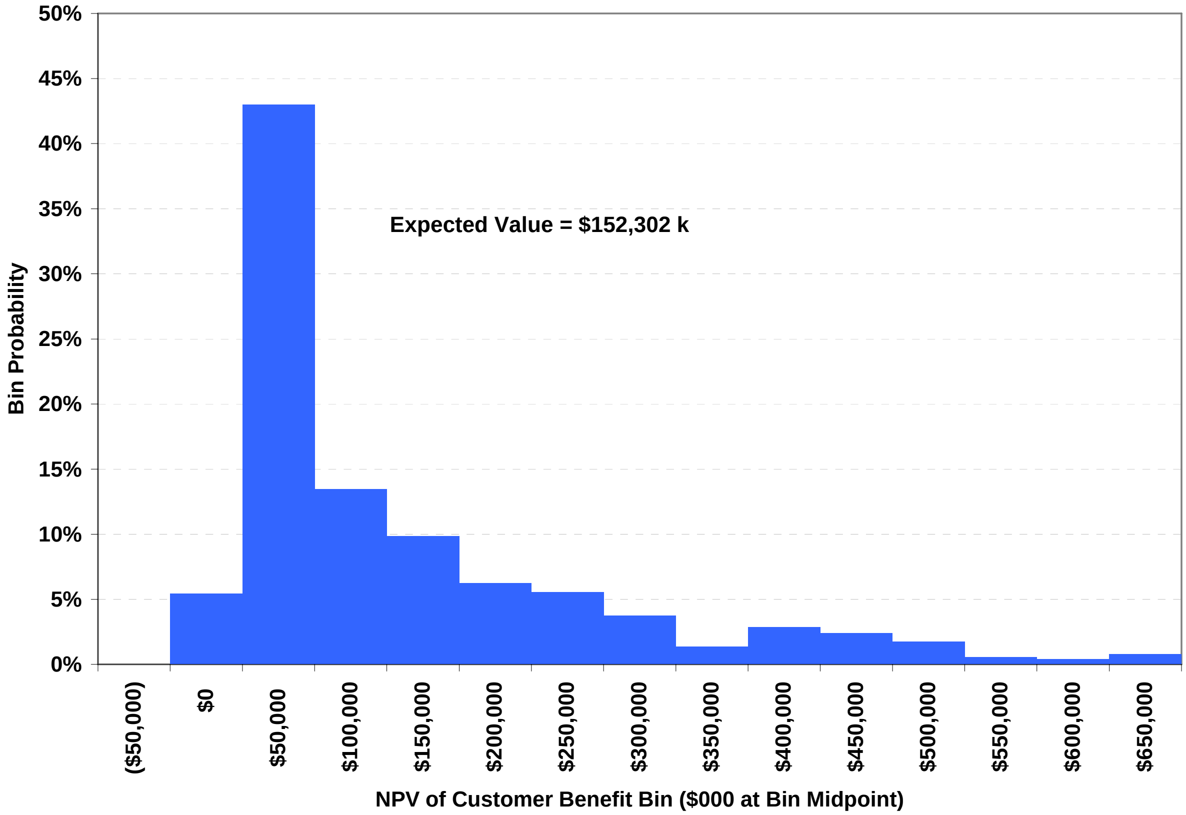
While on a ten-year NPV basis there is no modeled probability of a loss, Exhibit G.14 indicates that the annual energy net margin is very small at the 25% probability level. There is a 6% probability that small losses would occur in years 2017 and 2018. The timing of possible annual losses in these years is driven largely by the sudden uncertainty in capacity prices that begins then. The lead time of seven years before any probable losses are expected to occur means that a retirement decision should be deferred until such time that losses begin to occur.

**Exhibit G.14: Annual Distributions of Undiscounted Customer Benefits**



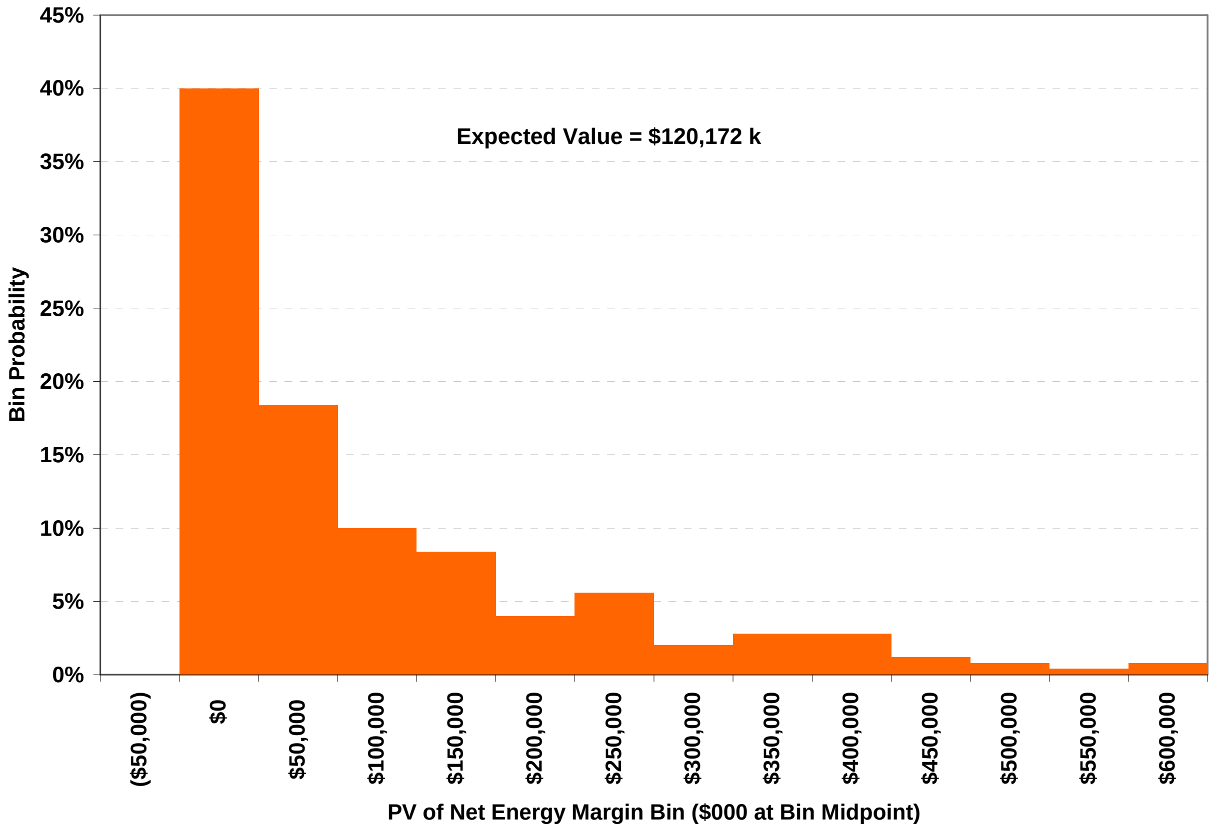

The skew in the distribution is more easily visualized in a probability distribution function histogram, shown in Exhibit G.15. Around the mean or expected NPV of $152 million, the distribution has a much longer right tail than left tail. While representing a small portion of the probable outcomes, the very large benefits in the right-hand tail of the histogram indicate a large portion of the hedge or insurance value of keeping Newington Station in operation. Without Newington, these low-probability but large benefits would instead be high cost outcomes for customers.

**Exhibit G.15: Probability Distribution of NPV of Customer Benefits**




A substantial portion of the right-tail skew of the NPV of revenue requirements reduction benefits is due to the completely skewed distribution of energy net revenues (revenues minus fuel and fuel-related expenses), shown in the histogram of Exhibit G.16. Around the expected NPV of energy net revenue of about $120 million ($308 million energy revenue minus $188 million fuel and emission costs), there are only three smaller bins but nine larger bins. The largest bin of energy net revenues is the left-most bin, and the probabilities drop off quickly at higher energy revenue levels. The reason the NPV of revenue requirements reduction distribution in Exhibit G.15 has a smaller leftmost bin than its second bin is due to the relatively symmetric weighting of the three capacity price scenarios (20%, 50%, and 30% probability, respectively, for the Low, Mid, and High price scenarios), combined with the assumption that fuel and energy prices are not correlated with capacity prices. The assumption of a zero correlation between energy and fuel prices versus capacity prices is a relatively conservative assumption. It is possible that the true correlation is slightly negative, meaning that if the spark spread for combustion turbine peaking units tended to decrease (increase) over time, then capacity prices would tend to be adjusted upwards (downwards), thereby mitigating the combined net impacts of capacity and energy products for generators and load.

**Exhibit G.16: Probability Distribution of NPV of Energy Net Revenue**




The annual capacity factor, service factor, number of starts, and fuel mix at the expected (mean), P50 (median), and P25 levels of energy net revenue for each year in the analysis (2011-2020) are shown in Exhibit G.17. The P50 and P25 results are for the individual scenarios at the $50^{th}$ and $25^{th}$ percentiles, respectively, of energy net revenue.

**Exhibit G.17: Operational Performance at Selected Annual Energy Net Revenue Probability Levels**

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Expected Value** | | | | | | | | | | |
| DAM Dispatch Hours | 1820 | 1620 | 1588 | 1745 | 1753 | 1825 | 1877 | 1960 | 1947 | 1958 |
| RT Dispatch Hours | 125 | 99 | 158 | 179 | 153 | 99 | 89 | 110 | 162 | 121 |
| Generation (GWh) | 585.9 | 517.0 | 534.8 | 594.1 | 582.0 | 580.7 | 593.2 | 627.3 | 647.3 | 631.4 |
| Number of Starts | 63 | 54 | 50 | 52 | 49 | 47 | 46 | 46 | 48 | 45 |
| #2 Oil Consumption (BBtu) | 13.4 | 11.6 | 11.0 | 11.1 | 10.7 | 10.0 | 9.8 | 9.9 | 10.2 | 9.7 |
| RFO Consumption (BBtu) | 142.1 | 100.4 | 330.9 | 505.9 | 311.6 | 114.9 | 90.2 | 153.6 | 418.9 | 205.2 |
| Gas Consumption (BBtu) | 6,171.7 | 5,476.6 | 5,425.8 | 5,881.0 | 5,950.5 | 6,137.4 | 6,295.1 | 6,595.0 | 6,536.7 | 6,584.8 |
| CO2 Emitted (1000 ton) | 374.4 | 330.0 | 347.0 | 388.8 | 375.9 | 369.7 | 376.8 | 399.8 | 419.5 | 403.7 |
| SO2 Emitted (ton) | 98.4 | 73.2 | 194.3 | 287.5 | 184.0 | 79.2 | 65.5 | 59.1 | 130.8 | 72.7 |
| NOx Emitted (ton) | 387.9 | 341.2 | 364.6 | 412.0 | 393.8 | 382.4 | 389.0 | 414.2 | 441.3 | 419.6 |
| Capacity Factor (%) | 16.7% | 14.7% | 15.3% | 16.9% | 16.6% | 16.6% | 16.9% | 17.9% | 18.5% | 18.0% |
| Service Factor (%) | 22.2% | 19.6% | 19.9% | 22.0% | 21.8% | 22.0% | 22.4% | 23.6% | 24.1% | 23.7% |
| Energy Revenue ($1000) | 45,636 | 41,347 | 42,894 | 47,691 | 45,326 | 43,934 | 44,399 | 46,564 | 48,563 | 47,313 |
| Energy Cost ($1000) | 29,879 | 26,721 | 27,347 | 29,365 | 27,760 | 25,944 | 25,606 | 26,606 | 27,991 | 26,739 |
| Net Revenue ($1000) | 15,757 | 14,627 | 15,546 | 18,325 | 17,566 | 17,991 | 18,793 | 19,959 | 20,571 | 20,573 |
| **P50 (Median)** | | | | | | | | | | |
| DAM Dispatch Hours | 1272 | 725 | 767 | 768 | 565 | 445 | 835 | 1021 | 591 | 852 |
| RT Dispatch Hours | 146 | 87 | 82 | 202 | 184 | 62 | 57 | 40 | 101 | 52 |
| Generation (GWh) | 428.1 | 245.4 | 258.7 | 309.4 | 241.2 | 157.2 | 265.4 | 315.9 | 234.3 | 271.6 |
| Number of Starts | 64 | 42 | 32 | 49 | 41 | 25 | 49 | 61 | 39 | 46 |
| #2 Oil Consumption (BBtu) | 11.8 | 11.0 | 8.1 | 9.5 | 9.8 | 7.1 | 9.6 | 12.5 | 9.5 | 9.8 |
| RFO Consumption (BBtu) | 135.9 | 235.1 | 107.2 | 582.7 | 550.4 | 183.0 | 24.5 | 24.0 | 1,004.6 | 89.6 |
| Gas Consumption (BBtu) | 4,452.6 | 2,429.6 | 2,691.2 | 2,748.1 | 2,054.0 | 1,523.9 | 2,856.9 | 3,409.0 | 1,514.6 | 2,855.8 |
| CO2 Emitted (1000 ton) | 273.2 | 163.4 | 167.4 | 212.1 | 168.7 | 105.6 | 170.0 | 202.5 | 176.6 | 175.6 |
| SO2 Emitted (ton) | 93.9 | 168.0 | 63.9 | 330.4 | 323.1 | 124.4 | 19.2 | 11.5 | 310.6 | 32.9 |
| NOx Emitted (ton) | 283.9 | 173.8 | 174.5 | 232.7 | 187.4 | 113.1 | 175.1 | 208.4 | 207.3 | 182.5 |
| Capacity Factor (%) | 12.2% | 7.0% | 7.4% | 8.8% | 6.9% | 4.5% | 7.6% | 9.0% | 6.7% | 7.7% |
| Service Factor (%) | 16.2% | 9.3% | 9.7% | 11.1% | 8.6% | 5.8% | 10.2% | 12.1% | 7.9% | 10.3% |
| Energy Revenue ($1000) | 35,970 | 23,871 | 21,500 | 28,860 | 23,788 | 16,876 | 21,716 | 23,363 | 24,643 | 23,933 |
| Energy Cost ($1000) | 26,901 | 17,442 | 15,380 | 21,872 | 18,391 | 12,172 | 17,284 | 17,872 | 19,022 | 17,263 |
| Net Revenue ($1000) | 9,070 | 6,430 | 6,119 | 6,987 | 5,397 | 4,705 | 4,432 | 5,492 | 5,621 | 6,670 |
| **P25** | | | | | | | | | | |
| DAM Dispatch Hours | 277 | 163 | 66 | 51 | 27 | 38 | 17 | 32 | 110 | 37 |
| RT Dispatch Hours | 20 | 19 | 19 | 0 | 6 | 11 | 0 | 0 | 0 | 0 |
| Generation (GWh) | 87.8 | 53.7 | 28.9 | 18.1 | 11.6 | 15.7 | 6.2 | 10.6 | 38.9 | 11.7 |
| Number of Starts | 23 | 13 | 8 | 4 | 3 | 4 | 1 | 2 | 9 | 4 |
| #2 Oil Consumption (BBtu) | 5.6 | 3.4 | 2.7 | 2.1 | 0.9 | 1.1 | 0.7 | 1.3 | 2.2 | 1.6 |
| RFO Consumption (BBtu) | 47.2 | 20.1 | 87.7 | 191.0 | 52.0 | 34.9 | 65.5 | 61.3 | 409.9 | 66.0 |
| Gas Consumption (BBtu) | 914.7 | 569.2 | 185.8 | 8.6 | 73.8 | 136.5 | 2.7 | 56.7 | 8.9 | 64.8 |
| CO2 Emitted (1000 ton) | 58.1 | 35.3 | 18.7 | 17.3 | 8.9 | 11.1 | 5.9 | 8.8 | 36.3 | 9.6 |
| SO2 Emitted (ton) | 32.9 | 14.9 | 51.5 | 108.1 | 30.5 | 23.7 | 46.2 | 23.1 | 126.4 | 23.1 |
| NOx Emitted (ton) | 60.8 | 36.8 | 21.5 | 22.7 | 10.5 | 12.3 | 7.8 | 10.6 | 47.9 | 11.6 |
| Capacity Factor (%) | 2.5% | 1.5% | 0.8% | 0.5% | 0.3% | 0.4% | 0.2% | 0.3% | 1.1% | 0.3% |
| Service Factor (%) | 3.4% | 2.1% | 1.0% | 0.6% | 0.4% | 0.6% | 0.2% | 0.4% | 1.3% | 0.4% |
| Energy Revenue ($1000) | 7,651 | 5,034 | 3,384 | 2,663 | 1,695 | 1,812 | 1,089 | 1,400 | 4,044 | 1,381 |
| Energy Cost ($1000) | 5,520 | 4,161 | 2,561 | 1,587 | 1,099 | 1,495 | 661 | 1,045 | 3,483 | 1,195 |
| Net Revenue ($1000) | 2,131 | 873 | 822 | 1,076 | 596 | 317 | 428 | 356 | 560 | 186 |

## F.5. Additional Insurance-Like Hedge Value Results

As discussed in Section E.2.2, in addition to Newington Station's operational flexibility and fuel-blending flexibility, which provide physical option values, the Station also helps to protect PSNH's customers from adverse market conditions on an annual and shorter-term timeframe in the power and fuel markets for forward and option contracts. Also, Newington Station provides RTM protection without the need to enter into contracts for supplemental power and outage insurance. Absent Newington Station, PSNH would consider entering into such arrangements to protect its customers during infrequent but financially costly events relative to the DAM when financially uncovered load increases significantly due to unanticipated weather or a forced outage at one of PSNH's generation units. These adverse wholesale market or forced outage conditions constitute comparatively low probability events, but they are not far-fetched or rare. When they occur, the cost consequences associated with such events can be high.

As discussed above, the Monte Carlo simulation modeling of Newington Station dispatch against uncertain DA and RT energy prices already includes the ability of the Station to undertake an additional start or ramp up its generation in response to RT prices that are higher than the DA prices. So the real-time insurance-like value of Newington Station is included in those simulated energy net revenue results, but not separately stated.[32] Also, since the simulated fuel and energy prices were calibrated to current forward market prices, they already include the market risk premia included within those forward prices. What that analysis does not include is the risk management value of the ability to dynamically exit and enter contract positions through time as the forecast of ES customer load obligations and market prices change. This combination of load risk and forward price movement risk may be approximated by the typical incremental risk premium over that of monthly block forward energy prices that is built into the prices for load-following contracts. Additionally, Newington Station's operational flexibility in service of PSNH's ES customers protects a larger relative amount of load fluctuation than that of a *pro rata* tranche of an energy load-following contract. Conservatively, an estimate of the additional financial hedge value of Newington Station's protection of residual load as well as market energy price fluctuations may currently be equivalent to about 10% of the price of monthly on-peak forwards.

## F.6. Capacity Price Suppression Benefits

LAI's capacity market model was used to quantify the reduction in FCA prices and the financial impacts in New Hampshire and New England when the supply curve moves to the left to reflect subtraction of 400 MW if Newington Station is retired*, all else being the same.* The price suppression impact increases over time. Results of LAI's price impact analysis are shown in Exhibit G.17 for the four capacity years 2016/17 to 2019/20. Lack of load forecast data prevents calculation of the impact for the seven months in 2020 of the 2020/21 capacity year.

Under LAI's Mid Case price forecast, the FCA price in the 2018-19 capacity year is $3.43 per kW-month, or $41.18 per kW-year. When Newington Station is removed from the supply stack, the FCA clearing price is $4.71 per kW-month, *all else being the same*. This equates to $56.48 per kW-year, an increase of 37%. Assuming a peak load in New Hampshire in 2018 equal to 2,295 MW, the monthly increased capacity cost of $1.28 per kW would cost customers throughout New Hampshire approximately $35 million in 2018. The

---

[32] In addition, LAI performed a quantitative investigation of the possible additional real-time risk mitigation benefit of Newington Station's operational flexibility by testing several statistical risk-averse DAM bidding strategies that on a probabilistic basis would reduce the cost of serving load. However, because of low predictability of RT price deviations from DA prices and the higher heat rate when Newington runs at part load instead of full load, these experiments did not result in a significant risk mitigation impact.

present value (at end of 2010) of the increased capacity costs for the 2016 through 2020 calendar years borne by New Hampshire load in total is about $104 million.

Of course, an announcement of the retirement of Newington Station would spur interest in developing new capacity in the local area in anticipation of higher energy and capacity prices upon the Station's closure. Another plant scheduled to retire may decide to wait and see the extent to which capacity prices are revitalized following the retirement of Newington Station. Therefore the aforementioned price suppression benefit represents an upper limit, and should certainly not be construed as an expected value. Still, the retirement of Newington Station would likely result in many millions of dollars of additional capacity costs for New Hampshire load.

**Exhibit G.18: Allocation of Net ICR Cost Savings to New Hampshire Customers of Continued Operation of Newington Station**

| Capacity Year | Net ICR and Representative Future Net ICR (MW) | New Hampshire Share (MW) | Base Case Clearing Price ($/kW-mo) | Alt Case Clearing Price ($/kW-mo) | Price Increase ($/kW-mo) | Additional Cost ($ 000/yr) |
|---|---|---|---|---|---|---|
| 2010/11 | 31,110 | 2,780 | 4.50 | 4.50 | 0.00 | 0 |
| 2011/12 | 31,741 | 2,813 | 3.60 | 3.60 | 0.00 | 0 |
| 2012/13 | 31,965 | 2,843 | 2.95 | 2.95 | 0.00 | 0 |
| 2013/14 | 32,127 | 2,869 | 2.95 | 2.95 | 0.00 | 0 |
| 2014/15 | 32,672 | 2,928 | 3.03 | 3.03 | 0.00 | 0 |
| 2015/16 | 33,178 | 2,989 | 3.08 | 3.08 | 0.00 | 0 |
| 2016/17 | 33,604 | 3,035 | 2.76 | 3.97 | 1.21 | 44,201 |
| 2017/18 | 34,025 | 3,084 | 3.13 | 4.38 | 1.24 | 46,038 |
| 2018/19 | 34,434 | 3,133 | 3.43 | 4.71 | 1.28 | 47,939 |
| 2019/20 | 34,818 | 3,181 | 4.41 | 5.72 | 1.31 | 49,890 |

Notes:

1. Net ICR does not include Hydro Quebec Interconnection Capability Credit load, which is also purchased at the capacity clearing price.
2. New Hampshire allocation is based on 2010 CELT load forecast details.
3. "Base" case prices in the table are the "Mid" price scenario of the uncertainty analysis.
4. Additional cost for the June through December 2020 tail end of the 2011-2020 CUO study period is not shown due to lack of load forecast data.

## G. Conclusions

Conclusions of the CUO analysis conducted by LAI are as follows. The quantitative analysis results in the finding that continued operation of Newington Station through 2020 is warranted, based on the following reasons:

➢ First, Newington Station provides PSNH's customers with 400 MW of capacity at a relatively known cost, thus providing a physical hedge against regulatory uncertainty associated with ISO-NE's administration of the FCM. While capacity prices are known with certainty for the next few years, many uncertainties have the potential to exert significant upward pressure on capacity prices from 2016 through 2020. Continued operation of Newington Station shields PSNH's customers from materially adverse economic consequences that may arise from evolving capacity market dynamics in New England. On an expected value basis, the net value of the physical capacity hedge is about $31 million. Under plausible worst case conditions the net value of the physical capacity hedge is about $54 million.

- Second, the expected NPV of customer benefits (decrease in incremental net revenue requirements) indicates substantial economic benefits associated with PSNH's continued operation of Newington Station. The expected NPV is $152 million, an outcome that can be represented as deep-in-the-money from PSNH's customers' perspective.

- Third, the risk of negative NPV of customer benefits is low. Simulation of market prices for capacity, energy, and fuels results in a 0% probability that the NPV of benefits will be negative. There is a 5% probability of an NPV outcome between zero and $25 million, and a 43% probability of NPV between $25 million and $75 million. The median result is $80 million. With respect to a positive "earnings surprise" related to continued operation of the Station, there is a 5% probability of an NPV greater than $498 million. One of the reasons why the NPV benefits are always positive from the customers' perspective is explained by the proper exclusion of Newington Station's sunk cost in the determination of going-forward cash costs through 2020.

- Fourth, the risk of not covering Newington Station's incremental revenue requirements in any single year over the ten year study period is low. On an expected value basis, Newington Station *always* covers its incremental revenue requirement. However, there is a 6% chance that market based revenues will be insufficient for Newington Station to cover its incremental revenue requirement in 2017 and 2018, evaluated separately. This is a result of the anticipated deterioration in capacity prices associated with the MW overhang in New England and ISO-NE's FCM restructuring proposal. The trough in the capacity price forecasts for the Low and Mid scenarios is the 2016/17 capacity year. A combination of low capacity prices and low energy net revenues in some simulated scenarios results in low total revenues in the 2017 and 2018 calendar years.

- Fifth, the distribution of economic benefits on an NPV or year-by-year basis is heavily skewed toward relatively small positive outcomes. Given Newington Station's operational characteristics and the range of anticipated capacity prices in New England over the study period, there is a low probability of very large benefits, in other words, only a 25% chance of an NPV greater than $200 million.

- Sixth, a large portion of the net benefit of Newington Station's continued operation is derived from its ability to operate flexibly in the DAM and RTM energy markets. The present value of fixed costs (direct and indirect fixed O&M, property taxes, and incremental depreciation and return on rate base) of $80.4 million is first offset by an expected value of capacity market revenues of $111.2 million, for a $30.8 million benefit. The remaining $121.5 million in expected value of net benefit is derived from net margins earned in the energy and ancillary service markets, and reflects the physical option values from the Station's operational dispatch flexibility and ability to burn natural gas and/or oil, including adjusting the blend of both fuels on-the-fly. The Station's operational flexibility allows it to serve as a physical hedge against volatile DAM and RTM energy prices, as well as volatile and unpredictable trends in the natural gas and oil commodity markets.

- Seventh, the additional insurance-like or financial hedge value of Newington Station as a substitute for energy load-following contracts is roughly estimated to be a risk premium equivalent to about 10% of the price of monthly on-peak contracts.

In addition to the more readily quantified benefits of continued operation, Newington Station also provides other benefits that are reported on a qualitative basis, as follows:

- First, the operational flexibility to adjust bidding in the DAM also allows PSNH to operate Newington Station at critical times of high load and high energy prices in a risk-averse manner to safeguard against bad economic outcomes in the RTM. The Station also serves to backstop a forced outage at one of PSNH's generation units. While an attempt was made to quantify the impact of changing bidding strategies at such critical times, the simulation results did not measure a significant risk reduction benefit. Given the study's limitation of not considering portfolio effects, no attempt was made to quantify the benefit of backstopping forced outages.

- Second, while Newington Station is operational, PSNH customers benefit from the real option value associated with waiting for more information before making a retirement timing decision. This benefit results from uncertainties across the fuels, energy, and capacity markets, but may be explained largely by the overarching uncertainty in New England's capacity markets. Keeping Newington Station operational while ISO-NE sorts out the retooling of the FCA therefore yields a sizable hedge value.

- Third, Newington Station's participation in the FCM provides capacity price suppression benefits to PSNH's customers as well as to other customers throughout New Hampshire. The indicative quantitative analysis performed is centered on the derivation of a maximum plausible price suppression benefit, and therefore constitutes a large value of preventing a significant increase in capacity prices in the absence of Newington Station.

- Fourth, the location and electrical interconnection of Newington Station provides several types of transmission and distribution system reliability benefits. Likewise, Newington's flexible fuel mix and large on-site oil tankage provides energy diversity benefits during cold snaps when natural gas deliverability is constrained.

- Fifth, Newington Station provides several types of operational support to the ISO-NE transmission system, including provision of load-following energy, spinning reserve and AGC. As VER technologies become a larger share of the resource mix, the value of load-following, spinning reserve, and AGC services will grow. Newington Station would be able to complement the new renewable VER resources.

- Sixth, regarding the ROV of potential modification, the Newington Station site has extra space to allow for the addition of quick-start gas turbine units. In addition, Newington Station could be repowered into an efficient combined cycle plant. Both resource possibilities provide the valuable real option of cost-effective capacity expansion at some future date if market conditions projected at that time are favorable.