PSNH GENERATION ASSET AND PPA VALUATION REPORT

PUBLIC VERSION

TECHNICAL REPORT

Prepared for

New Hampshire Public Utilities Commission

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GLOSSARY & ACRONYMS

ACP	Alternative Compliance Payment
A&G	Administrative and General
AEO	Annual Energy Outlook
CEPS	Competitive Electric Power Suppliers
CONE	Cost of New Entry
CO_2	Carbon Dioxide
CSO	Capacity Supply Obligation
CVPS	Central Vermont Public Service
DCF	Discounted Cash Flow
DCR	Debt Coverage Ratio
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EIA	Energy Information Administration
FCM	Forward Capacity Market
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FR	Forward Reserve
kW	Kilowatt
LFRM	Locational Forward Reserve Market
LMP	Locational Marginal Pricing
MACRS	Modified Accelerated Cost-Recovery System
MtM	Mark-to-Market
MWh	Megawatt-hour
NHDES	New Hampshire Department of Environmental Services'
NHEC	New Hampshire Electric Cooperatives
NHPUC	New Hamphire Public Utilities Commission
NMM	La Capra Associates' proprietary Northeast Market Model
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NU	Northeast Utilities
O&M	Operation and maintenance
PM&E	Protection, Mitigation and Enhancement
PNGTS	Portland Natural Gas Transmission System
PPA	Purchased Power Agreement
PSNH	Public Service Company of New Hampshire
REC	Renewable Energy Credit

RGGI	Regional Greenhouse Gas Initiative
RoS	Rest of the System
RPS	Renewable Portfolio Standards
RRB	Rate Reduction Bond
RSA	Revised Statutes Annotated
SCR	Selective Catalytic Reduction
STEO	Short Term Energy Outlook
TMNSR	Ten Minute Non- Spinning Reserves

1. EXECUTIVE SUMMARY

La Capra Associates, Inc. (La Capra Associates) and ESS Group, Inc. (ESS) were retained by the New Hampshire Public Utilities Commission (NHPUC) to conduct an economic valuation of the fossil, hydro and biomass generating assets of Public Service Company of New Hampshire (PSNH) as well as the market value of the Purchased Power Agreements (PPAs) with the Lempster Wind and Burgess BioPower facilities. The valuation is part of NHPUC Docket IR 13-020, "Investigation into Market Conditions Affecting PSNH and its Default Service Customers and the Impact of PSNH's Ownership of Generation on the Competitive Electric Market."

New Hampshire initiated electric utility industry restructuring in 1996 with legislation creating Revised Statutes Annotated (RSA) 374-F, Electric Utility Restructuring. In the early 2000s, New Hampshire amended its restructuring laws to direct PSNH to retain ownership of its fossil and renewable generation assets on behalf of default service customers, at least through April 2006. The current investigation in Docket IR 13-020 seeks to determine the disposition of PSNH's remaining generation assets and PPAs that is most in the public interest. An estimate of fair market value is an important piece in projecting the rate impacts of retiring or selling the assets and entitlements.

La Capra Associates' determination of the value of the generation assets is based primarily on a discounted cash flow (DCF) analysis of anticipated future costs and revenues. This analysis is supported with an analysis of comparable sales, though the uniqueness of power generation assets, the small number of contemporaneous transactions, and the lack of public transaction details limit the reliability of comparable sales in determining value. The determination of value of the PPAs is based on a mark-to-market analysis of anticipated future costs and revenues.

The DCF methodology is a common methodology employed for power generation asset valuations, being the predominant method used by asset buyers, asset valuation and appraisal organizations, and regulatory applications.

The DCF methodology requires assessments of the future market conditions, future operations of the generator, and future costs to operate and maintain the assets over their remaining useful life. Power generation assets are typically long-lived assets; valuation therefore requires that judgments be made pertaining to significant uncertainties and risks inherent in long-term forecasts of uncertain parameters. Nevertheless, asset buyers participating in a competitive market for assets will make such assessments of risk in arriving at an offer price for acquiring the asset.

Our DCF analysis presented herein makes those same assessments of uncertain parameters and seeks to make judgments of value consistent with those that would be expected in a competitive auction of the assets. We developed a Reference Scenario with forecasts of key parameters that are intended to represent an outlook that a typical third party buyer would use as "50/50 forecasts".[1] We accounted for uncertainty by developing additional scenarios and sensitivities to test alternative outlooks for key parameters such as natural gas prices and operating expenses.

The economic valuation of the PPAs relies on the same assessment of future market conditions relied upon for the generation asset valuations. Based on an analysis of the conditions in the contract, we compared the projected costs of power delivered under the contract relative to the cost of obtaining the same amount of power in the spot markets.

We relied heavily on PSNH data and projections related to plant operating characteristics, costs and revenues. PSNH provided helpful input through responses to discovery questions, conference call discussions with subject matter experts within the Company and its parent, Northeast Utilities (NU), site tours of the fossil plants and two hydro units. PSNH did not offer its own long term forecasts of energy or fuel prices, or its own recent valuation study.

ESS conducted a high level review of environmental conditions for the PSNH generating assets as part of this valuation ESS prepared a report ("ESS Report") detailing the scope, methodology and conclusions of their review, which is submitted as an attachment to this report. The objective of the assessment was to generally identify known and potential environmental matters that could lead to substantial expenditures for future compliance, i.e. the need for environmental controls or future liabilities potentially due to soil or groundwater conditions at the sites that could influence the cost of operations. The assessment was based on information as provided by the PSNH through discussion and information requests and also through readily available information obtained by ESS from the New Hampshire Department of Environmental Services' (NHDES) website or Environmental Protection Agency website.

The ESS review involved mainly the three largest assets: Merrimack, Newington, and Schiller Stations with the focus being three main areas of environmental concern: cooling water, air quality, and site assessment/conditions. ESS also reviewed the smaller peaking generating units (White Lake and Lost Nation) with respect to air quality as well as the hydroelectric generating facilities with respect to water quality and discharge permit status. No major environmental compliance issues beyond those already raised by PSNH were identified in the review.

Generation assets derive market value directly from their ability to produce power. Many of the inputs related to energy output and revenue are derived from the La Capra Associates Northeast Market Model (NMM). The La Capra Associates NMM uses an hourly chronologic electric energy market simulation

1 A "50/50 forecast" is one that the forecaster believes has equal probability to overestimate actual values or underestimate them.

model on the AURORAxmp® software platform (AURORA). The model provides a zonal representation of the electrical system of New England, New York and the neighboring regions.

The underlying technology, AURORA, is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA captures the dynamics and economics of electricity markets.

AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, demand-side management (DSM), generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses. The La Capra Associates NMM is described in greater detail in the attached confidential Technical Report, *Northeast Market Model January 2014 PSNH Asset Valuation* ("NMM Report").

New England electric energy prices are highly correlated with the price of natural gas in the region, as natural gas-fired facilities are at the margin in the market and set the market clearing prices for energy during most hours. Over the last several years, the price of natural gas in New England has been subject to two major and countervailing trends. At the commodity level, revolutionary breakthroughs in natural gas and oil production have opened vast resources throughout the country that had previously been economically infeasible to tap. The Henry Hub (commodity) price of natural gas fell more than 50% between 2008 and 2013, and most long-term forecasts have declined in similar proportions. At the same time, interstate pipeline congestion has constrained supply that can be transported into New England, particularly in the winter, leading to spikes in the basis differential to New England over the last 15 months.

The Reference Scenario natural gas price forecast is based on long-term projections from the U.S. Department of Energy's Energy Information Administration (EIA) Annual Energy Outlook 2013 (AEO 2013) Reference Case. In the first few years of the forecast, we substitute the January 2014 Short Term Energy Outlook (STEO) and market futures pricing data to capture short-term effects, including the current high basis differentials.

The Reference Scenario forecast of New Hampshire zone locational marginal prices (LMPs) is shown in the figure below.

[redacted]

Confidential Figure ES- 1: Reference Scenario New Hampshire Zone LMP Forecast ($/MWH)

La Capra Associates maintains its own proprietary models for forecasting capacity and renewable energy credit (REC) prices. The New England capacity markets have been subject to significant regulatory intervention, market design changes, and price volatility in the past few years. The Reference Scenario capacity price forecast for resources in New Hampshire is shown in Figure ES-2 below.

[redacted]

Confidential Figure ES- 2: Reference Scenario Rest of System Capacity Prices

Forecasting energy prices is an inherently difficult process due to the complex nature of energy markets and the uncertainty of key driver variables. Due to this uncertainty it is often helpful to construct additional scenarios that help illustrate the range of potential results. For the purposes of this valuation

we selected several key variables and modeled non-reference values that present a reasonable range of future uncertainty in New England wholesale energy prices.
The key variables we selected were:

- Delivered natural gas prices;
- Potential future federal carbon legislation;
- The potential for adding a new transmission project to import Canadian hydropower; and
- The potential for higher retirements (and subsequently higher capacity costs) in New England

We also constructed generation asset-specific sensitivities that tested alternative values for key parameters within the Reference Scenario DCF analysis. The sensitivity variables were:

- REC revenues;
- Operation and maintenance (O&M) expense;
- Cooling system requirements at Merrimack

The DCF analysis relies on a spreadsheet pro forma that is similar to the type of financial model used by owners and buyers of merchant generation assets. Projected revenues and expenses are entered for all years over the book life of each asset. The acquisition price and subsequent capital additions are financed according to an assumed mix of debt and equity available to a typical third party buyer using non-recourse financing. Depreciation is calculated using standard IRS modified accelerated cost-recovery system (MACRS) schedules. The model solves for a value that provides the cash flow to equity sufficient to meet the target internal rate of return over the book life of the asset, subject to certain minimum debt service. The pro forma is set up to provide a valuation as of 12/31/2014.

Table ES- 1 below summarizes the conclusions from our valuation of PSNH's generation assets. The total reconciled value of the PSNH fleet is $225 million. Most of that value is found in the hydro units and Newington. We conclude that Merrimack and Schiller Stations hold little to no fair market value, compared to their remaining net plant value, to a third party buyer continuing to operate as currently configured.

Table ES- 1: Summary of PSNH Generation Assets Valuation

Plant/Unit	Net Plant Value (12/31/2013)	DCF-indicated Value Range[2]	DCF-indicated Value	Comparable Sales Range	Final Reconciled Value
		Million 2014$			
Fossil Plants					
Merrimack Station	$500	<$0 - $159	$0	$0 - $15	$10
Schiller Station	$78	<$0 - $36	$0	$0 - $5	$5
Newington	$36	$79 - $103	$90	None found	$90
Combustion Turbines					
Lost Nation	$0.4	<$0 - $0	$0	$0	$0
White Lake	$0.2	<$0 - $0	$0	$0	$0
Hydroelectric Units					
Ayers Island	$9.6	$9.5-$18.8	$14.5	$15.6 - $20.1	$14.5
Canaan	$2.7	$1.7 - $3.2	$2.5	$2.5 - $3.3	$2.5
Gorham	$1.0	$2.3 - $4.7	$3.5	$4.2 - $5.3	$3.5
Eastman Falls	$5.5	$3.2 - $7.8	$5.5	$8.9 - $11.5	$5.5
Smith	$6.3	$34.8 - $60.7	$47.0	$38.8 - $49.9	$47.0
Merrimack River Project (Amoskeag, Garvins and Hooksett)	$17.0	$26.6 - $60.7	$45.0	$50.1 - $64.4	$45.0
Jackman	$4.6	$0.9 - $3.2	$2.0	$3.4 - $4.4	$2.0
All Hydro	*$46.8*	*$76.0 - $152.9*	*$120.0*	*$123.5 - $158.8*	*$120.0*
Total PSNH Fleet[3]	***$660***		***$210***		***$225***

The Mark-to-market (MtM) analysis of the PPAs compares the products purchased and the payments made to purchase those products to the market value of those purchased products. If the PPA payments are expected to be less than the market value of the products, then the PPA is considered to be "below market" and would therefore have a positive valuation. If the PPA payments exceed the

2 Cases in which the DCF does not solve indicate a negative value under a continuous operation scenario. We did not attempt to quantify negative values because in these scenarios the unit would likely be retired rather than operated at a loss for the 15-year book life.

3 Does not include PSNH minority ownership share in Wyman Station. Numbers may not add due to rounding.

market value of the products purchased, the PPA is considered to be “above market”, and would have negative value.

Our MtM analysis was conducted using spreadsheet models of the anticipated contract payments and market replacement value over the remaining terms of the contracts. The value of the contracts is the net present value (NPV) of the MtM gains or losses. Since there is no physical asset associated with the sale of a PPA, we assume any transaction would be a completely unleveraged cash transaction. We therefore use our return on equity of 12% as the discount rate in the NPV analysis.

Based on the range of MtM results under the Reference and alternative scenarios, as well as high and low REC price sensitivities, we conclude that the value of the Burgess BioPower PPA is negative $125 million, and the value of the Lempster Wind PPA is $5 million. In other words, PSNH would need to pay a third party buyer about $125 million to assume the rights and obligations of the Burgess BioPower PPA as of 12/31/2014. Conversely, a third party buyer would be willing to pay PSNH $5 million to assume the rights and obligations of the Lempster Wind PPA as of 12/31/2014.

2. INTRODUCTION

2.1 Project Overview

On September 18, 2013, the New Hampshire Public Utilities Commission (NHPUC) issued an RFP seeking the services of qualified asset valuation consulting firms to perform a comprehensive valuation of the generating assets of Public Service of New Hampshire (PSNH) and two purchased power agreements (PPAs) executed by PSNH. The primary assignments included: a description of the market for fossil and hydro assets in the New England region, specifically, and the Northeast, generally; an overview of the operating characteristics and competitiveness of the PSNH generating assets in the New England region; an assessment of value of the assets by unit (Newington, Merrimack, Schiller, Hydroelectric, other); an assessment of whether the value of the PSNH generating assets would bring more value if sold separately, as one bundled sale of all the generating assets, or as smaller groups of assets (e.g., fossil and hydro assets grouped separately); an estimate of the market value of PSNH's two PPAs and an evaluation of the plant sites for environmental contamination, based on existing records. The RFP requested a report to the NHPUC detailing its results, including its methodologies and assumptions used in the valuation study as well as any risks not quantified, but that could affect the value of the assets.

La Capra Associates, Inc. and ESS, Inc. teamed together to submit a joint proposal to the NHPUC to perform the desired analysis. The La Capra Associates/ESS team was selected by the NHPUC. This report provides the detail results of the valuation of PSNH assets.

2.2 Background

The NHPUC is an administrative agency with executive, legislative and quasi-judicial powers. The NHPUC's prime responsibility is as an arbiter between the public utilities and their ratepayers. Proceedings in this regard address such areas as public utility rates, financing, terms and conditions of utility service, quality of service, safety and reliability, eminent domain matters, public utility exemptions from local zoning ordinances, public utility franchises, utility crossings of public lands and waters, wholesale relationships between utilities, rulemakings and consumer complaints.

In 1996, New Hampshire passed legislation to open up its retail electricity markets to competition. RSA 374-F, Electric Utility Restructuring, states that "[T]he most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets." RSA 374-F:1 Purpose. Broad regulatory guidance was provided in RSA 374-F:3 Restructuring Policy Principles, which included maintaining system reliability, customer choice, unbundling rates, open access, universal service for all customers, full and fair competition, the recovery of stranded costs, and a commitment to renewable energy and energy efficiency.

The NHPUC opened up a proceeding on electric restructuring, Docket No. DR 96-150, and after a lengthy proceeding issued "Restructuring New Hampshire's Electric Utility Industry: Final Plan on February 28, 1997." The Final Plan included details on implementation of electric restructuring for each New Hampshire electric utility, including the recovery of stranded costs based on the policy directives contained in RSA 374-F, including that New Hampshire's electric rates should "to the greatest extent practicable … approach competitive regional electric rates." Litigation followed issuance of the Final Plan and New Hampshire restructured its electric industry on a case-by-case basis over the ensuing years. After more than two years of litigation with PSNH, a multi-party comprehensive settlement was reached and filed with the NHPUC in August 1999 ("Agreement to Settle PSNH Restructuring") and approved by the NHPUC on April 19, 2000 in Docket No. DE 99-099.

Based on the settlement agreement, PSNH agreed to lower average retail rates by 18.3%, write off $225 million after-tax of its stranded cost charges, recover its remaining stranded costs in three "buckets" that included a risk-sharing provision, sell off its generating assets and entitlements, and securitize up to $725 million of rate reduction bonds (RRBs) which required and received legislative approval. An updated settlement agreement was filed with the NHPUC in June 2000 that included recovery of the RRBs and new retail rates. Soon afterward, concerns about high energy prices in the new electric markets, especially based on the volatility and market prices in California resulted in changes to New Hampshire's electric restructuring. The Legislature passed HB 489 in 2001, which amended electric restructuring in New Hampshire and directed PSNH to keep its fossil-hydro assets and to use them for default service during a transition period.[4] The divestiture of ownership interest in nuclear plants including the Seabrook Nuclear Station, of which PSNH had a 36% entitlement of the power through its affiliate, North Atlantic Energy Company, was not affected by HB 489 (see RSA 369-B:3,IV(b)(13)). The NHPUC, in consultation with and supported by the Connecticut Department of Public Utility Control, hired an asset sales company, JP Morgan, to conduct the sale. The sale to FPL Group for approximately $798 million, which included 88.2% of the ownership interests in Seabrook, closed in November 2002. PSNH also sold its ownership interests in the Millstone 3 nuclear plant and the Vermont Yankee nuclear plant before the end of 2002.

For the first several years of electric restructuring in New Hampshire, PSNH's Transition Service rates were set by legislation. After the legislatively mandated rates expired, the rates were set annually by the NHPUC based on PSNH's actual and prudent costs to provide Transition Service and later Default Service. PSNH uses its 1,100 MW of fossil-hydroelectric generating assets as well as market purchases to provide default service. Although PSNH's rates have been above and below market rates over the past decade, since 2009 PSNH's default service rate has trended above market as indicated by the default service prices of Unitil Energy Systems (UES) and Granite State Electric Company (GSEC), two New

4 HB 489 prohibited PSNH from divesting its fossil and hydro generation assets for at least 33 months after the initiation of retail choice -- effectively February 2004. SB 170, enacted in 2003, pushed the date to April 30, 2006, though it also allowed for the retirement or modification any units prior to that date if such action were found to be in the public interest. Since April 2006, PSNH has been neither prohibited from, nor required to sell its remaining generation assets by New Hampshire statute.

Hampshire regulated electric utilities that provide default service using a competitive auction process. PSNH's default service rate, $0.0854 per kWh, was approximately 1.5 cents per kWh higher than the default service rate of either GSEC or UES, at the time of the RFP. Low natural gas prices and the installation of a wet flue gas desulfurization project at Merrimack Station have contributed to that differential as well as the significant migration of customer load to Competitive Electric Power Suppliers (CEPS).

On January 18, 2013, the NHPUC issued an Order of Notice in IR 13-020, Investigation into Market Conditions Affecting PSNH and its Default Service Customers and the Impact of PSNH's Ownership of Generation on the Competitive Electric Market (Market Conditions Report). In opening the investigation, the NHPUC described the history of electric restructuring in New Hampshire, the current "hybrid" system in effect for PSNH in which PSNH's default service rates are reviewed annually by the NHPUC and set based on PSNH's actual cost of service and the changes in market conditions that are affecting PSNH's costs of providing default service to a decreasing customer base as customers continue to migrate to CEPS.

On June 7, 2013, the Staff of the NHPUC and the Liberty Consulting Group issued "Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market." The Report analyzed the current conditions affecting PSNH's default service rates and the factors affecting the substantial amount of load that has migrated to CEPS over the past two years.

After receiving the Report, the NHPUC issued a Secretarial Letter stating that interested parties would be afforded the opportunity to file comments on the Market Conditions Report. Comments were received from the Office of the Consumer Advocate, TransCanada, the Retail Energy Supply Association, North America Power and Gas, LLC, the New England Power Generators Association, the Conservation Law Foundation, the Sierra Club, and PSNH.

The NHPUC accepted the Report and issued Order No. 25,525 on July 15, 2013 that stated, "we do not adopt all of its assumptions or conclude that the information contained therein is necessarily proven as fact."[5] The NHPUC found that the Report demonstrates a credible risk of harm to PSNH and its customers if circumstances were to continue unchecked. The NHPUC found it necessary to further analyze the economic and regulatory pressures facing PSNH. Even as the NHPUC considered the various recommendations for next steps offered by stakeholders, it stated that a threshold question for many discussions will be the value of PSNH's generation assets and the rate impacts if those assets were retired or sold. Towards that end, the NHPUC directed Staff to engage a valuation expert, through a competitive bid process, to determine the value of PSNH's generation assets and entitlements. This information, which will be more precise than the general assessment of value in the Report, will be of

5 Order No. 25,525 (July 15, 2013) at 5.

use to the Commission and the Legislature both of which are likely to consider further action in these matters, as well as PSNH and the many stakeholders affected by PSNH's operations."

2.3 Assets and Contracts Subject to Valuation

2.3.1 Merrimack Station

Merrimack Station is located on the western shore of the Merrimack River in Bow, Merrimack County, NH. The Facility consists of two coal-fired generation units with a net installed capacity of 459.2 MW and two combined combustion turbines with a net installed capacity of 37.2 MW. Both coal-fired units utilize Westinghouse turbines/generators and Babcock & Wilcox tangentially-fired cyclone boilers. Unit 1 began commercial operation in 1960 and Unit 2 began commercial operation in 1968. Emissions control equipment installed at Merrimack includes a selective catalytic reduction (SCR) system, electrostatic precipitator, and a wet lime flue gas desulfurization (FGD) system. The combustion turbines were manufactured by the Pratt and Whitney division of United Technologies and burn Grade A jet fuel. The first unit was installed in 1968 with an Electric Machine generator and the second unit was installed in 1969 with a Westinghouse generator. The coal-fired units burn low ash (maximum fusion temperature 2,400 degrees Fahrenheit) bituminous coal sourced from South America and Northern Appalachia. International coal shipments are received by marine vessel at the Schiller dock facilities and trucked just over 50 miles to Merrimack. Northern Appalachian coal arrives by rail directly to the site.

2.3.2 Schiller Station

Schiller Station has had a total of six units at different points in time, but currently runs four generating units. Units 4 and 6 are capable of burning coal or oil, Unit 5 runs on wood biomass, and one combustion turbine burns primarily jet fuel. Units 4, 5, and 6 (the coal/oil and wood biomass units) have a total installed capacity of 150 MW and began commercial operation in 1952, 1955 and 1957 respectively. These generating units utilize Westinghouse turbines/generators and Foster-Wheeler boilers. A new fluidized bed boiler capable of burning biomass fuel was installed at Schiller 5 in 2006. The combustion turbine is a jet engine, which was manufactured by Pratt and Whitney of United Technologies Corporation and utilizes either Grade A jet fuel or natural gas and has an Electric Machine generator. The combustion turbine began commercial operation in 1970. The Schiller Station is located in Portsmouth, NH on the shore of the Piscataqua River, immediately downriver from Newington. The facility includes docks with oil and coal off-loading equipment that receives fuel used at all three fossil stations. There are indoor and outdoor wood storage facilities that can accept up to [redacted] tons of wood chips trucked in by over [redacted] local suppliers[6]. The Facility also includes [redacted] barrels of oil storage tanks that are shared with Newington.

6 PSNH Response to Liberty-I-022 and LCA-011.

2.3.3 Newington

Newington, located on the Piscataqua River just upriver from Schiller Station in Newington, NH, is the largest single unit in the PSNH system. The unit was originally designed in 1974 to burn oil, but was modified in 1992 to utilize natural gas as well. The 414 MW (nameplate) Facility includes a main turbine and generator manufactured by Westinghouse. Newington is connected via a lateral to the jointly owned Portland Natural Gas Transmission System (PNGTS) and Maritimes & Northeast interstate gas pipeline.[7] Most of Newington's oil storage capacity is shared with and located at Schiller Station.

2.3.4 Standalone Combustion Turbines

PSNH owns two combustion turbines that are not co-located with larger fossil steam stations.

Lost Nation is an 18 MW (installed capacity) generation station consisting of a 5,100-RPM oil-fired turbine/generator manufactured by GE. The power plant is located in Groveton (also known as Northumberland), New Hampshire and was first installed in 1969. The facility includes two 50,000 gallon capacity fuel oil storage tanks. Lost Nation can be operated locally or from the Electric System Control Center in Manchester, NH.

White Lake is an 18.6 MW (nameplate) generating station consisting of a 3,600-RPM Grade A jet fuel – fired turbine/generator manufactured by Whitney Division of United Technologies. White Lake was installed in 1968 and is located in Tamworth, NH. The station is located within the perimeter of a transmission substation. The site includes four fuel oil storage tanks with a combined capacity of 120,000 gallons. White Lake can be operated locally or from the Electric System Control Center in Manchester, NH.

2.3.5 Hydroelectric Plants

The Merrimack River Project (FERC Project No. 1893) consists of the Amoskeag, Hooksett and Garvins Falls developments, located along a 21-mile stretch of the Merrimack River flowing into Manchester. The Project was issued its original license in 1980, which expired in 2005; it operated under an annual license until the license was renewed in 2007 for a period of 40 years.

Amoskeag is a 16 MW (nameplate) hydro power station composed of three generating units and a 710-foot-long gravity dam, which includes low and high crest sections, each with their own flashboards impounding a reservoir. A pneumatic crest gate system, or "rubber dam", was installed on the low crest section in 2009. The development also contains a stone masonry training wall, 35.5 kV double circuit transmission line, substation, and other appurtenances. For fish, there is a pool and weir type fish ladder at the powerhouse with an eel trap and downstream fish passage at the waste gate. The dam and

7 PSNH Response to LCA-012.

control structures are operated in a run-of-river mode and designed to meet minimum flow requirements as outlined in its FERC license. Amoskeag is the furthest downstream development of the Merrimack River Project.

Hooksett is a single-unit 1.6 MW (nameplate) hydro power station, which includes a dam with a masonry section, the associated flashboards impounding a reservoir, a Taintor gate, a substation, and other appurtenances. There is a downstream fish bypass system between the Taintor gate and the powerhouse. The Hookset development lies between Amoskeag and Garvins Falls in Hookset, NH on the Merrimack River. The dam and control structures are operated in a run-of-river mode and designed to meet minimum flow requirements as outlined in its FERC license.

Garvins Falls is a 12.3 MW (nameplate) hydro power station composed of two powerhouses, each with two generating units, and a concrete and granite gravity dam with low and high crest sections, each with their associated flashboards impounding a reservoir. The Facility also contains a power canal, waste gate, louver-type fish guidance downstream bypass system, 35.5 kV transmission line, substation, and other appurtenant facilities. The Garvin Falls development is located in Bow, NH and is the furthest upstream of the three hydroelectric facilities that comprise the Merrimack River Project. The dam and control structures are operated in a run-of-river mode and designed to meet minimum flow requirements as outlined in its FERC license.

Ayers Island (FERC Project No. 2456) is PSNH's northernmost hydro station in the Merrimack River Basin located on the Pemigewasset River, twelve miles upriver of the U.S. Army Corps of Engineers Franklin Falls Flood Control Dam, which releases into a 1.5 mile reach of the river known as the Bristol Gorge. The development's primary features include a concrete Ambursen dam with the associated spillway, flashboards, and Broome-type gate, an impoundment upstream of the dam, a reinforced concrete and brick powerhouse with three generating units each rated at 2.8 MW, and three 1.2 kV transmission lines. The Facility was granted its original license in 1967, which expired in 1993; it operated under an annual license until the license was renewed in 1996. The dam and control structures are designed to meet minimum flow requirements as outlined in its FERC license.

Canaan (FERC Project No. 7528) is a hydro power station consisting of a concrete gravity dam with the associated spillway, stoplogs, flashboards, waste gate section with high steel Taintor gate, and a gatehouse with an intake structure that connects to a wood stave penstock. A single generating powerhouse has an installed capacity of 1.1 MW. The development also includes two surge tanks, an impoundment, a tailrace and a 34.5 kW transmission line that connects to the regional grid. The Facility is situated between Coos County, NH and Essex County, VT; the penstock, powerhouse, and tailrace cover 1,800 feet of the Connecticut River. The Facility was granted its original license in 1984, which expired in 2009, when its license was reissued. The dam and control structures are operated in a run-of-river mode and designed to meet minimum flow requirements as outlined in its FERC license.

Eastman Falls (FERC Project No. 2457) is a 6.4 MW (nameplate) hydro power station located on the Pemigewasset River in the City of Franklin, approximately 1.5 miles downstream from the U.S. Army Corps of Engineers Franklin Falls Flood Control Dam, in Merrimack and Belknap Counties, New Hampshire. The Facility includes a reinforced concrete gravity dam, hinged steel flashboards, steel waste gate, powerhouse with a 4.6 MW unit and a 1.8 MW unit, transmission line, and other appurtenant facilities. PSNH was granted its first license for this plant in 1969, which expired and was renewed in 1987 for a license period of 30 years. The dam and control structures are operated in a run-of-river mode and designed to meet minimum flow requirements as outlined in its FERC license.

Gorham (FERC Project No. 2288) is a 2.15 MW (nameplate) hydro power station located on the Androscoggin River in Gorham, New Hampshire. The development includes a timber crib, L-shaped dam with two associated spillway sections with wooden flashboards and a sluiceway section with wooden flashboards. The Facility also contains an earthen power canal, reservoir, powerhouse with four generating units (two 400-kW Allis Chalmers generators driven by two 583-horsepower S. Morgan Smith vertical, Francis-type turbines and two 675-kW Allis Chalmers generators driven by two 1,000-horsepower Allis Chalmers vertical, propeller-type turbines), 33-kV transmission line, and other appurtenant facilities. PSNH was issued the license for the Gorham Project in 1994 for a period of 30 years. The dam and control structures are operated in a run-of-river mode and designed to meet minimum flow requirements as outlined in its FERC license.

Smith (FERC Project No. 2287) is a single-unit 15 MW (nameplate) hydro power station located near the confluence of the Androscoggin River and Dead River in Coos County, New Hampshire. The Facility consists of a masonry and concrete gravity U-shaped dam including two associated spillway sections with flashboards and two steel roller-type sluice gates as well as an intake structure with a power canal, penstock and steel surge tank. The development also contains a reservoir, 115-kV transmission line and other appurtenant facilities. PSNH was issued the license for the J. Brodie Smith Project in 1994 for a period of 30 years. In 2006 PSNH replaced the existing turbine with a new, more efficient turbine, increasing generation by 8%. The dam and control structures are operated in a run-of-river mode and designed to meet minimum flow requirements as outlined in its FERC license.

Jackman is a 3.2 MW (nameplate) single-unit hydroelectric facility that is considered a storage reservoir project, whereby water held in the Franklin Pierce Reservoir travels through a penstock and turns a turbine to generate electricity. The development includes a surge tank and other associated equipment and structures used in hydropower generation. The Facility is located in Hillsborough, NH. The development does not require a FERC license because it is not located on a navigable waterway, but is registered with the NHDES Dam Bureau and began commercial operation in 1926.

2.3.6 Purchased Power Agreements

Burgess BioPower ("Burgess") is a 75 MW nameplate generating facility located in Berlin, NH. PSNH has signed a long-term purchased power agreement (PPA) to purchase the capacity, energy, and RECs produced by this facility. La Capra Associates was provided a copy of the Amended and Restated Agreement dated May 18, 2011 between PSNH and Laidlaw Berlin BioPower, LLC. The facility is a Qualifying Facility under PURPA that burns wood biomass as fuel. The term of the PPA is 20 years.

According to information provided by PSNH, Burgess started testing in [redacted].[8]

Pursuant to the PPA, PSNH will purchase capacity, energy, and RECs produced by the Burgess Facility.[9] Capacity is purchased at fixed annual rates specified in the PPA. The capacity rates are as follows:

- Years 1 - 2: $2.95 per KW-month.
- Years 3 - 5: $4.25 per KW-month.
- Years 6 – 20: increase each year's rate by +$0.15 per KW-month over the previous year's value.

Energy is purchased by PSNH according to a rate formula in the PPA. The energy rate is $69.80 per MWH plus 1.6 multiplied by the difference between (a) Schiller 5's actual cost of wood per ton and (b) $30 per ton.

RECs produced by Burgess, up to 400,000 RECs per year, are purchased by PSNH at rates that are a certain percentage of the annual Alternative Compliance Payment (ACP) for NH class I RECs. The ACP rate in the contract is locked in at levels in statute when the contract was executed. In 2013 legislation was enacted to reduce the ACP by more than $10/MWh for 2013, and cut the growth rate for subsequent years in half.[10]

- Years 1 – 2: 50% of ACP
- Years 3 – 7: 80% of ACP

8 Email communication from William Smagula. February 4, 2014.

9 The key contract provisions discussed here are publicly available in the Commission's April 18. 2011 Order No. 25,213, Order Granting Conditional Approval of Purchased Power Agreement with Laidlaw Berlin BioPower, LLC (Docket DE 10-195).

10 See RSA 362-F:10, as amended by SB 148 and HB 542.

- Years 8-12: 75% of ACP
- Years 13 – 19: 70% of ACP
- Years 18 – 20: 50% of ACP

The Burgess PPA contains a provision that limits the amount paid by PSNH for energy relative to market prices. The difference between energy payments per the rates described above and the value of the energy produced at ISO-NE market prices is tracked on a cumulative basis. The cumulative amount by which PPA energy payments exceed the market value of the energy is referred to as the Cumulative Reduction. If, at the end of any year, the Cumulative Reduction exceeds $100 million, the amount in excess of $100 million is deducted from the PPA energy payments for the following year.

The Burgess PPA also provides PSNH with the option to purchase the Burgess facility at end of the term of the PPA. The acquisition price is the fair market value of the Burgess facility, less any Cumulative Reduction that exists at the term of the contract. The Cumulative Reduction cannot exceed $100 million.

Lempster Wind LLC (“Lempster”) is a 24 MW nameplate wind generating facility located on Lempster Mountain in Lempster, NH. The facility is a Qualifying Facility that went on-line at the end of 2008. In January 2008, PNSH entered into a PPA to buy the output of this facility. The facility entered commercial operation at the end of 2008 and the term of the PPA is 15 years. The value of the Lempster PPA is being determined as of December 31, 2014, which means that the valuation of this PPA is based upon the last 9 years of the contract’s 15-year term.

The energy purchase price is the greater of (a) [redacted] of ISO-NE real time LMPs or (b) a monthly floor price of [redacted] per MWH. The capacity price is [redacted] of the Forward Capacity Market (FCM) prices [redacted]. The PPA also provides for PSNH to buy the RECs at a fixed price schedule.

- Years 1 – 5: [redacted] per MWH
- Years 6 – 10: [redacted] per MWH
- Years 11 – 15: [redacted] per MWH

Under the PPA, Lempster has the option to re-purchase RECs that were sold to PSNH at a price that is [redacted] per MWH higher than PSNH paid originally. For years 1-10, Lempster may re-purchase up to [redacted] of the RECs sold to PSNH, and [redacted] of the RECs sold in years 11 – 15.

The Lempster PPA allows PSNH to purchase capacity and energy at a discount off of ISO-NE market prices, so long as energy prices are above the floor energy price, and shares in upside REC prices. Lempster receives a floor price on energy and a portion of its RECs, with an upside potential for higher prices.

PSNH also has a contract with New Hampshire Electric Cooperatives (NHEC) to [redacted].

2.4 The Valuation Team

La Capra Associates is an energy consulting firm with offices in Boston, MA, Portland, ME, and Williston, VT. La Capra Associates is a consulting firm specializing in electric market assessments and economic analysis of generation assets and power contracts on behalf of many clients including asset buyers, asset owners, and regulatory agencies. Our work includes asset valuation in asset transactions, property tax determinations, and regulatory proceedings considering the cost of generating assets or proposed asset acquisitions. Our consulting practice also includes extensive analysis of the ISO New England markets and forecasting the future prices in those markets based on analysis of market fundamentals in market simulation models and review of futures indices, where available.

La Capra Associates performed the majority of the task required by the RFP, except for the required environmental assessment which was performed by ESS.

ESS is a multidisciplinary full service environmental engineering and consulting firm with offices in East Providence, Rhode Island, Waltham, Massachusetts, and Norfolk, Virginia. ESS provides comprehensive environmental consulting to address a variety of environmental media and regulatory program requirements. ESS specializes in environmental and engineering services for energy and power development and operational compliance. ESS provides a full range of energy project consulting services that includes feasibility assessments, engineering design, environmental resource evaluations, environmental impact assessments, and regulatory reporting and permitting. Our consulting has supported energy policy development and we advise clients regularly as requirements change in response to new technologies and environmental requirements. ESS is experienced and very familiar with the environmental permitting requirements for electric generating facilities in New Hampshire including impacted soil and or groundwater requirements.

Both La Capra Associates and ESS have extensive experience in the planning, evaluation, operation, and valuation of generating plants.

La Capra Associates served as the project leader, directed the interface with the Commission Staff, and was responsible for all project deliverables. ESS served as a subcontractor to La Capra Associates in performing the environmental assessment.

2.5 Scope of Work

In completing this report, the valuation team completed the following key tasks:

1. Reviewed the materials on the record in IR 13-020, Investigation into Market Conditions Affecting PSNH and its Default Service Customers and the Impact of PSNH's Ownership of Generation on the Competitive Electric Market.
2. Conducted discovery as needed, including interviews with key players in the New England energy market, such as ISO-NE.
3. Conducted site visits of the PSNH generating plants and interviewed key PSNH personnel concerning the operation and maintenance of the plants;
4. Reviewed the market for fossil and hydro assets in the New England region, specifically, and the Northeast, generally.
5. Reviewed the operating characteristics and competitiveness of the PSNH generating assets in the New England region.
6. Assessed fuel markets (e.g., natural gas, coal, oil, biomass, etc.) generally, and for the ISO-NE region, specifically.
7. Assessed potential risks and market changes affecting long-term market values, such as planned or expected plant retirements, natural gas shortages in New England, possible pipeline expansion, hydro power from Canada, and/or environmental Clean Air and Clean Water compliance, including analysis of whether a cooling tower will be required at any of the plants.
8. Conducted an evaluation of the plant sites for environmental contamination (based on existing records).
9. Performed an assessment of value of the assets by unit (Newington, Merrimack, Schiller, Hydroelectric, other). Also assessed whether the PSNH generating assets would bring more value if sold separately, as one bundled sale of all the generating assets, or as smaller groups of assets (e.g., fossil and hydro assets grouped separately).
10. Performed an estimate of the market value of PSNH's two PPAs.
11. Drafted written report for Staff review.
12. Prepared final report.

3. VALUATION METHODOLOGY

La Capra Associates' determination of the value of the generation assets is based primarily on a discounted cash flow ("DCF") analysis of anticipated future costs and revenues. This analysis is supported with an analysis of comparable sales. The determination of value of the PPAs is based on a mark-to-market analysis of anticipated future costs and revenues.

The DCF methodology is a common methodology employed for power generation asset valuations, being the predominant method used by asset buyers, asset valuation and appraisal organizations, and regulatory applications.

The DCF methodology requires assessments of the future market conditions, future operations of the generator, and future costs to operate and maintain the assets over their remaining useful life. Power generation assets are typically long-lived assets; valuation therefore requires that judgments be made pertaining to significant uncertainties and risks inherent in long-term forecasts of uncertain parameters. Nevertheless, asset buyers participating in a competitive market for assets will make such assessments of risk in arriving at an offer price for acquiring the asset.

Our DCF analysis presented herein makes those same assessments of uncertain parameters and seeks to make judgments of value consistent with those that would be expected in a competitive auction of the assets. We developed a Reference Scenario with forecasts of key parameters that are intended to represent an outlook that a typical third party buyer would use as "50/50 forecasts".[11] We accounted for uncertainty by developing additional scenarios and sensitivities to test alternative outlooks for key parameters such as natural gas prices and operating expenses.

The Comparable Sales method is an alternative valuation methodology that can, at times, provide useful benchmarks for valuing power generation assets. However, power generation assets are generally unique assets, limiting the availability of true comparable asset transactions.[12] There are typically few if any contemporaneous comparable asset transactions, which is the case in this instance. We use transactions most nearly comparable in time and type as a reasonableness check on our DCF results and consider that information in forming an opinion on reasonable value.

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11 A "50/50 forecast" is one that the forecaster believes has equal probability to overestimate actual values or underestimate them.

12 Determinations regarding the comparability of asset transactions must consider factors of asset characteristics, market characteristics, and time of the transaction. The attributes of the facility or facilities such as heat rate, age, river flow (for hydro) and fuel type are important considerations. The markets into which their output and services are sold are material due to significant variations by location. The time of the transactions has bearing on changes in market fundamentals that determine expected revenues. Some transactions also include additional assets such as administrative buildings, land and pondage that can significantly impact value.

The information on the costs, performance and condition of the Facility is based on information disclosed by PSNH in this proceeding. The statements of value contained in this report assume that there are no undisclosed liabilities associated with the facilities or facilities operations other than as expressly discussed herein. Any such additional liabilities, such as undisclosed issues with the condition of facilities and equipment could negatively impact the value of the Facility and are not considered in our valuation analysis.

The economic valuation of the PPAs relies on the same assessment of future market conditions relied upon for the generation asset valuations. Based on an analysis of the conditions in the contract, we compared the projected costs of power delivered under the contract relative to the cost of obtaining the same amount of power in the spot markets.

3.1 Discounted Cash Flow Analysis

Our DCF analysis uses a financial pro forma analysis for a hypothetical third party buyer ("Third Party Buyer") of the Facilities as of December 31, 2014. For this analysis, we assume 15 years of future operations for the thermal generation units and 33 to 40 years of future operations for the hydroelectric generation units under the remaining years of current FERC licenses and, in some cases, continued operations under a new 30-year license. Our method also assumes the Third Party Buyer will employ 15-year or 20-year, non-recourse financing typical of power asset transactions. This formulation includes the following inputs:

1. Revenues for Facility power output derived from La Capra Associates' Northeast Market model based on sales of Facility output into the New England wholesale market;
2. Revenues for Facility capacity output derived from La Capra Associates' forecast of New England Forward Capacity Market prices;
3. Additional revenues from the sale of RECs derived from La Capra Associates' forecast of relevant RPS market prices;
4. Power production levels based on the dispatch modeling for thermal units and historical operations for hydroelectric units;
5. Operating and maintenance expenses for the continued operation of the Facility, based on review of historical operations data and budget information disclosed by PSNH, as well as sensitivities based on analysis of expenses at comparable units;
6. Requirements for capital improvements, including consideration of the environmental assessment conducted by ESS; and
7. Costs of debt and equity and financing requirements based on current market conditions.

Our discounted cash flow analysis relies on a financial model which solves for an initial value or acquisition price that provides the cash flow to equity sufficient to meet the target internal rate of return over the life of the asset. This internal rate of return is different from the return on equity established for regulated utilities. A return on equity is typically measured over a one-year period. An internal rate of return is measured over the asset's life and is calculated differently. An internal rate of return analysis is what investors typically examine when evaluating an asset acquisition.

3.2 Comparable Sales

Our Comparable Sales analysis uses our survey of generation asset transactions over the past few years. Information from the market on values placed on similar assets can provide direct evidence of market value or reasonable indicators to supplement the DCF assessment of value. Each asset and transaction is unique, however, and the utility of comparable sales to assign fair market value to power assets is limited. Many transactions are for bundles of multiple generation and non-generation assets, and assumptions must be made about the division of value among individual components.

For hydroelectric units, we use an index to compare these transactions by dividing the sale price by the average annual energy production, as the Facility and comparable hydroelectric assets derive most of their value from energy markets. The comparable transactions are limited in number, particularly for assets of this size within the past few years in the New England Market.

Market prices and expectations of market prices have dropped significantly since 2008. Since energy revenue is the primary driver of asset value for hydroelectric power, the rapid erosion in market prices has made transaction prices for assets sold only three or four years ago no longer reflective of current market conditions.

3.3 Mark-to-Market Analysis

PPAs are valued in a mark-to-market analysis using many of the same forecast and assumptions used in the DCF analysis of the owned generation assets. For these agreements, we will compare the forecast of revenues from the sale of asset attributes to the annual payments under the contracts to determine if these PPAs are above market or below market. PPAs that are below market may be sold for positive prices. PPAs that are above market may require PSNH to pay the counterparty to "buy out" of the contract purchase obligations.

4. DATA SOURCES

4.1 PSNH Data

We relied heavily on PSNH data and projections related to plant operating characteristics, costs and revenues. A project kick-off meeting was held December 2, 2013 at PSNH headquarters in Manchester. PSNH President William Quinlan and representatives from PSNH and its parent company Northeast Utilities (NU), NHPUC Staff, La Capra Associates and ESS discussed proposed valuation methodology and opportunities for collaboration.

An informal discovery process was used to facilitate information flow. PSNH made available the electronic data room containing responses to Staff and Liberty Consulting in the initial valuation stage. La Capra Associates and ESS submitted an initial set of questions prior to the December 2nd kick-off meeting, and additional questions on an ongoing basis. PSNH provided confidential responses to La Capra Associates/ESS questions on an ongoing basis. All responses to our initial set were received by January 24, 2014. Responses to all additional questions were made promptly, with the final response completed by February 4.

In addition to written discovery, three informal subject matter discussions were held. In a series of conference call meetings held in December, subject matter experts from PSNH/NU presented the Company's perspective on key issues affecting the valuation, including commodity markets (natural gas, capacity, energy), generation performance (operational characteristics, bidding, O&M costs), and environmental compliance issues. In response to discovery requests, PSNH noted that [redacted].

4.2 Site Visits

To facilitate our work in valuing the generating assets, La Capra Associates and ESS personnel conducted site visits on two days in February. On February 19, 2014 we visited Schiller and Newington station. On February 21, 2014, we visited Merrimack Station and hydroelectric generating facilities at Garvins Falls and Amoskeag. The purpose of these visits was not to conduct a detailed operational audit but rather to see facilities first hand, speak with station personnel, and get an overall feel for how these plants are operated and maintained.

We found these plants to be of typical design for power plants of their vintage. The plants were clean, well-maintained, and staffed by knowledgeable personnel. The excellent condition of the plants is supported by our analysis of company O&M costs, where costs for some units appear to be slightly higher than for comparable units. It was obvious from the discussions with the plant managers and the operators that the employees take great pride in these facilities. According to the Company, the plants have excellent safety records, with a minimal amount of reportable accidents. Operator logs were kept via computers and manual operator diaries. Appropriate tagging provisions seemed to be in place. Because of cold weather and high market prices, all three units at Schiller were in operation at or near full load. We were able to witness wood fuel deliveries that would be used in Schiller Unit Five. Newington Station was off line due to economy but discussions with operators indicated they had been called on by ISO-NE to operate in January more than normal. One unit at Merrimack was online and the other unit was off-line due to boiler maintenance issues. We were able to view the inside of a boiler via an open cyclone burner. The company described recent reductions in the staffing and changes in the culture at the plants. Plant staffing levels have declined in recent years. Because of declining capacity factors, it became important for plant staff to understand ISO-New England markets, and to recognize that at times it would not be economic to operate these facilities, according to the Company. These visits resulted in a positive perception of the plants.

4.3 ESS Report

ESS conducted a high level review of environmental conditions for the PSNH generating assets as part of this valuation of PSNH's generating assets and purchased power agreements. ESS prepared a report for La Capra Associates ("ESS Report") detailing the scope, methodology and conclusions of their review, which is submitted as an attachment to this report.

The objective of the assessment was to generally identify known and potential environmental matters that could lead to substantial expenditures for future compliance, i.e. the need for environmental controls or future liabilities potentially due to soil or groundwater conditions at the sites that could influence the cost of operations. The assessment was based on information as provided by the PSNH through discussion and information requests and also through readily available information obtained by ESS from the NHDES website or Environmental Protection Agency website.

The review involved mainly the three largest assets: Merrimack, Newington, and Schiller Stations with the focus being three main areas of environmental concern: cooling water, air quality, and site assessment/conditions. ESS also reviewed the smaller peaking generating units (Groveton and Tamworth) with respect to air quality as well as the hydroelectric generating facilities with respect to water quality and discharge permit status.

5. REVENUE FORECAST

Generation assets derive market value directly from their ability to produce power. In this section, we describe our Reference Scenario assessment of the outlook for power production and the value of that production in the wholesale markets.

5.1 Energy Output

Many of the inputs related to energy output and revenue are derived from the La Capra Associates Northeast Market Model ("NMM"). The La Capra Associates NMM uses an hourly chronologic electric energy market simulation model on the AURORAxmp® software platform ("AURORA"). The model provides a zonal representation of the electrical system of New England, New York and the neighboring regions.

The underlying technology, AURORA, is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA captures the dynamics and economics of electricity markets.

AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, demand-side management (DSM), generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses. The La Capra Associates NMM is described in greater detail in the attached Technical Report, *Northeast Market Model January 2014 PSNH Asset Valuation* (NMM Report).

Projected energy output for Merrimack, Schiller and Newington were taken directly from NMM output. Operating characteristics such as minimum load, full load average heat rate, heat rate at minimum, minimum up time and emission rates were updated in the NMM based on data provided by PSNH.[13] Reference Scenario unit output is shown in the figure below (dashed lines), benchmarked to recent history (solid lines).

13 PSNH responses to LCA-001 and LCA-002.

[redacted]

Confidential Figure 1: History and Forecast of Energy Output at Merrimack, Schiller and Newington Stations

Hydroelectric resources are not represented in the NMM with the degree of granularity that would make it appropriate to forecast unit-specific output from the model.[14] Instead, long-term average production was estimated for eight of the nine hydro units using an average of historical production from the nearly 22 year period of 1992 – October 2013.[15] Smith Hydro installed a new, more efficient turbine runner in 2006 that increased efficiency by 8.21%.[16] Since there is not a long record of production at Smith in its current configuration, we relied on the FERC order certifying the Production Tax Credit for a production estimate.[17] Annual output assumed for the hydroelectric units is shown in the table below.

14 Key hydro input parameters apply to the zone rather than individual units, so there is very little differentiation among run-of-river units in the same zone.

15 PSNH Response to LCA-006.

16 PSNH Response to LCA-038.

17 118 FERC ¶ 62,217, Order Certifying Incremental Hydropower Generation for Production Tax Credit. (Issued March 22, 2007).

Table 1: Projected Long-term Average Production for Hydro Units

Unit	Annual Output (MWH)
Amoskeag	[redacted]
Ayers Island	[redacted]
Canaan	[redacted]
Eastman Falls	[redacted]
Garvins Falls	[redacted]
Gorham	[redacted]
Hooksett	[redacted]
Jackman	[redacted]
Smith	[redacted]
Hydro Total	[redacted]

The standalone combustion turbines, White Lake and Lost Nation, typically operate [redacted]. The net revenue realized from energy generation by these resources is de minimis, and was therefore ignored (along with fuel and variable costs) in this valuation.

5.2 *Energy Revenue*

PSNH generation fleet energy revenues are estimated assuming the energy output is sold in the ISO New England wholesale energy market at locational marginal prices (LMPs) in the New Hampshire Zone. LMP forecasts are derived from the NMM, which is documented in detail in the NMM Report.

New England electric energy prices are highly correlated with the price of natural gas in the region, as ISO-NE relies on natural gas-fired generation more than any other fuel type. During most hours of the year, natural gas-fired facilities are at the margin in the market and set the market clearing prices for energy. In 2012, natural gas was on the margin in 80% of all hours.[18]

Over the last several years, the price of natural gas in New England has been subject to two major and countervailing trends. At the commodity level, revolutionary breakthroughs in natural gas and oil production have opened vast resources throughout the country that had previously been economically infeasible to tap. The Henry Hub (commodity) price of natural gas fell more than 50% between 2008 and 2013, and most long-term forecasts have declined in similar proportions. At the same time, interstate pipeline congestion has constrained supply that can be transported into New England, particularly in the winter, leading to spikes in the basis differential to New England over the last 15 months.

18 2012 Annual Markets Report, ISO New England, May 15, 2013, at p 17. http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2012/amr12_final_051513.pdf.

The Reference Scenario natural gas price forecast is based on long-term projections from the U.S. Department of Energy's Energy Information Administration (EIA) Annual Energy Outlook 2013 (AEO 2013) Reference Case. In the first few years of the forecast, we substitute the January 2014 Short Term Energy Outlook ("STEO") and market futures pricing data to capture short-term effects, including the current high basis differentials. Based on our review of a number of natural gas price outlooks from several sources and market participants, we conclude that this AEO case is representative of the reference case forecast that would be used for asset valuation by market participants in the current market environment. However, because natural gas prices represent such a highly impactful uncertainty this valuation, we also ran High and Low Gas scenarios to determine the range of values under different natural gas outlooks. The figure below shows the range of New England delivered natural gas price forecasts considered. See Section 2.4 of the NMM Report for a more detailed discussion of the natural gas price forecast.

[redacted]

Confidential Figure 2: Reference, High and Low Gas Scenario forecasts of Algonquin City Gate natural gas prices.

Another key uncertainty in the energy price outlook is future pricing of carbon dioxide ("CO_2") emissions. Vermont and eight other Northeast states participate in the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions through a cap-and-trade program affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. RGGI allowance prices have been minimal since the program began in 2009 because actual CO_2 emission levels have fallen well below the initial program caps. On February 7, 2013 the RGGI states announced their commitment to an Updated Model Rule that would tighten the caps significantly in 2014. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will rise from about $4 (2010$) per ton in 2014 to over $10 (2010$) per ton by 2020.

Federal policy regarding greenhouse gas emission remains a potential, though uncertain, outcome. Congress has considered several legislative options that would create a cap-and-trade market for CO_2 emission allowances over the past several years. Legislative activity was high in the 2008-2010 session, although no action was taken and the prospects of action in the near-term have lessened considerably since the 2010 elections. Nevertheless, proponents for addressing climate change remain active and the possibility of future legislative action on this issue remains.

The Reference Scenario assumes that a federal program that places a price per ton on CO_2 emissions is implemented beginning in 2020. Prices under the federal program are based on the "Low" case of Synapse Energy Economics, Inc.'s 2012 Carbon Dioxide Price Forecast.[19] Prior to 2020, the RGGI program continues to place a low but significant price on CO_2 emissions under the Updated Market Rule. RGGI prices are based on the recent RGGI-commissioned IPM modeling of the Updated Market Rule.[20] The Reference Scenario CO_2 price forecast is shown in the figure below.

[redacted]

Confidential Figure 3: Reference Scenario CO_2 Emission Prices ($/ton)

The Reference Scenario assumes that a new transmission project is completed, adding 1,200 MW transfer capability from Quebec into New England in 2019. It assumes that Vermont Yankee and Brayton Point retire as currently planned in 2014 and 2017, respectively. Renewable resources – particularly wind and solar – are added in sufficient levels to comply with currently-enacted renewable portfolio standards (RPS). Beginning in 2022, capacity shortfalls caused by retirements and load growth are met

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[19] The "Low" case was chosen because we believe it is closer to a typical "50/50" forecast being used by market players today than the "Reference" case. Also, continued federal inactivity on CO2 cap and trade since the Synapse study was published in late 2012 make the lower case more appropriate.

[20] RGGI, Inc. 2/7/2013 Press Release. http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf. See also "IPM Analysis of RGGI Model Rule Scenario," http://www.rggi.org/docs/ProgramReview/February11/13_02_11_IPM.pdf

with additional generic natural gas combined cycles and combustion turbines. These and other assumptions are discussed more fully in the NMM Report. The Reference Scenario forecast of New Hampshire zone LMPs is shown in the figure below.

[redacted]

Confidential Figure 4: Reference Scenario New Hampshire Zone LMPs ($/MWH)

Energy revenues for Merrimack, Schiller and Newington are taken directly from NMM output, which matches hourly output with hourly prices for each unit. For hydro resources, the long-term annual production forecast described in the previous section is converted to a monthly peak and off peak shape using three years of hourly output data.[21] This shaped output is multiplied by monthly peak and off-peak prices for the New Hampshire zone from NMM. White Lake and Lost Nation earn negligible net energy revenues, so energy revenue and variable costs were ignored in this analysis.

5.3 Capacity Revenue

Capacity revenues for PSNH are estimated assuming the capacity output from each asset is sold in the ISO New England Forward Capacity Market (FCM), continuing the current practice. Each facility has qualified for capacity credit in all of the forward capacity market auctions (FCAs) conducted to date. In the four most recent FCAs with data available[22], covering capacity commitment periods 2013-2014, 2014-2015, 2015-2016 and 2016-2017, the capacity supply obligation (CSO) for each asset is shown in the table below:

21 PSNH Response to LCA-0 [look up number]

22 FCA 8, covering supply obligation period 2017-2018, was conducted on [date] but the unit CSOs had not yet been made public as of the time of the analysis.

	FCA 4 2013-14	FCA 5 2014-15	FCA 6 2015-16	FCA 7 2016-17
AMOSKEAG	15.8	15.8	17.5	17.5
AYERS ISLAND	7.9	7.9	9.1	8.5
CANAAN	0.9	0.9	0.9	0.9
EASTMAN FALLS	5.1	5.1	5.6	5.6
GARVINS/HOOKSETT	11.6	11.6	14.0	14.0
GORHAM	2.1	2.0	2.0	2.0
JACKMAN	3.5	2.4	3.4	3.4
LOST NATION	14.1	14.1	14.1	14.1
MERRIMACK 1	112.5	112.5	112.5	112.5
MERRIMACK 2	320.0	335.5	335.5	335.5
MERRIMACK CT1	16.8	16.8	16.8	16.8
MERRIMACK CT2	16.8	16.8	16.8	16.8
NEWINGTON 1	400.2	400.2	400.2	400.2
SCHILLER 4	47.5	47.5	47.5	47.5
SCHILLER 5	43.1	43.1	43.1	43.1
SCHILLER 6	47.9	47.9	47.9	47.9
SCHILLER CT 1	17.6	17.6	17.6	17.6
SMITH	11.5	11.5	11.7	11.7
WHITE LAKE JET	17.4	17.4	17.4	17.4
Total	**1,112.3**	**1,126.6**	**1,133.6**	**1,132.9**

Figure 5: Capacity Supply Obligations for PSNH's assets

However, PSNH projections of capacity revenue indicate [redacted].[23] We have assumed that units receive capacity payments on the CSO budgeted for by PSNH through FCA 7, and then hold the FCA 7 CSO value constant for the remainder of the study period.

The FCM auctions conducted to-date (as of March 1, 2014) have established the capacity market prices that the assets will receive through the 2018-2019 capacity commitment period, as depicted in the figure below:

23 PSNH Response to LCA-035a, Attachment LCA-I-035a&b Confidential – IR 13-030.xls.

	Capacity Year	FCM Payment Price for Rest of Pool
FCA1	2010-11	$ 4.254
FCA2	2011-12	$ 3.119
FCA3	2012-13	$ 2.535
FCA4	2013-14	$ 2.516
FCA5	2014-15	$ 2.855
FCA6	2015-16	$ 3.129
FCA7	2016-17	$ 2.744
FCA8	2017-18	$ 7.025

Figure 6: FCM Prices for Auction conducted

The established capacity prices have ranged between $2.5/kW-month and $4.3/kW-month until FCA 8 that resulted in $7.025/kW-month. Although ISO-NE capacity markets have provided low price volatility, it is not uncommon for capacity prices to fluctuate between capacity periods as denoted in Figure 7. This volatility is due to market design limitations and uncertainty from possible future market enhancements.

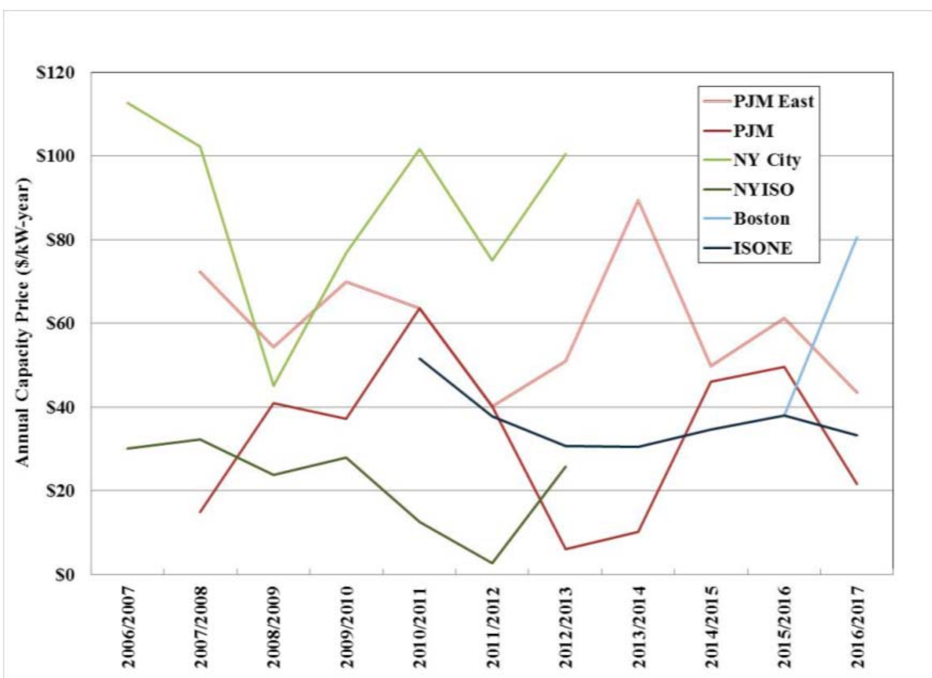

Figure 7: Capacity Clearing Prices in each RTO/ISO and select sub regions for commitment periods between 2006-2017[24]

24 FERC. August 23, 2013. Centralized Capacity Market Design Elements: Commission Staff Report AD13-7-000, p. 3. http://www.ferc.gov/CalendarFiles/20130826142258-Staff%20Paper.pdf.

Initially, all three eastern ISOs/RTOs approved market designs that procured a fixed amount of capacity equal to the planning reserve margin in a form of a vertical demand curve. A vertical demand curve implies that capacity will be procured regardless of the price at which it is offered. The prices resulting from the use of the vertical demand curve were too volatile and could swing dramatically from near zero or the established floor price, when there was excess supply, to near the maximum, when supply was inefficient. At ISO-NE the established capacity prices were at the floor price up to FCA 7, due to the excess supply in the ISO-NE capacity market. This changed in FCA 8 when the market experienced a slight system resource shortfall that resulted in steep capacity price elevation - a byproduct of the vertical demand curve. If this slight system shortfall changes to a small system surplus in the next auction, there is a high probability of the capacity prices to collapse close to the floor price. For example, if the capacity shortfall is 300 MW and a 400 MW resource is added in the next auction, there is a possibility of the price dropping down to the floor. The implementation of a demand curve will alleviate this behavior and provide more stable prices in the future.[25] NYISO and PJM have adopted a downward-sloping demand curve, while ISO-NE was ordered by FERC to do the same by April 1, 2014. A demand curve is important because it allows a trade-off to be made between reliability and cost. It also helps mitigate strategic bidding in the market because it provides an auction price cap and flexibility to procure less capacity if the price is high.

We believe that besides the effect of the vertical demand curve, the capacity price in FCA-8 was affected by uncertainties from potential new FCM market enhancements. The Pay for Performance initiative proposed by ISO-NE[26] included modifications to the FCM design to make each resource's FCM revenue contingent, in part, upon its actual performance during periods when aggregate performance does not allow ISO to satisfy system reserve requirements. The new market rules, if approved, will result in FCM payment transfers from under-performing to over performing resources providing strong incentives for better performance during elevated system needs. These incentives will place a performance risk on all FCM resources and this risk will be priced in each resource's bid in future capacity auctions, potentially elevating the FCM prices. Also, there is a possibility that a significant amount of resources did not participate in FCA 8 due to the risks caused by the uncertainties of these new enhancements. More specifically, a small amount of withholding has the ability to force a relatively large increase in price, particularly if the amount of offered supply is close to the planning reserve margin target. We believe that after these uncertainties are removed, upon approval of the new rules, and the market better understands the associated risks, there will be increased market participation.

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25 In the years following implementation of the downward-sloping demand curve, the NYISO Market Monitor confirmed that the demand curve addressed the volatility concerns. http://www.hks.harvard.edu/hepg/Papers/NYISO_2004_state_of_the_market_report.pdf

26 ISO-NE Filings related to FCM Perfomance Incentives are located at: http://iso-ne.com/key_projects/fcm_perf_incentives/iso_ne_filings/

Our forecast of capacity prices for the study period reflects anticipated supplies in the market and assumes that the transmission constraint for Maine resources remains throughout the study period. Also, it includes the implementation of the demand curve further analyzed below. The forecast for the "Rest of System" zone (which includes New Hampshire) is shown in the figure below.

[redacted]

Confidential Figure 8: FCM Price forecast for the study period ($/kW-month)

On January 24 2014, FERC issued an Order which, among other things, required that ISO-NE submit Market Rule changes by April 1 2014 to implement a sloped Demand Curve in time for FCA 9. The implementation of the sloped Demand Curve signifies that ISO-NE will model the demand in the Forward Capacity Auction similarly to Figure 9 and will discontinue the use of the vertical demand curve. At the time of the writing of this report, ISO-NE and its stakeholders were in process of developing a demand curve. The forecasted FCM prices included in Figure 8 assumes Brattle Group's proposed curve[27], which is not necessarily the final demand curve that will be established later this year.

The demand curve slope is described in the figure below. It assumes $8.30/kW-month as Cost of New Entry (CONE).

27 Brattle Group. February 6, 2014. Capacity Demand Curve in ISO-NE: Responses to Initial Stakeholder Inquiries. Accessed from http://www.iso-ne.com/key_projects/fcm_sloped_dem_curve/mc_mtrls/,. Slide 3.

	Cap to Kink (Steep Section)	Kink to Foot (Flat Section)
Change in Price ($/kW-m)	$10.8	$5.8
Change in Quantity (MW)	1,492	2,166
Slope ($/kW-m per 100 MW)	$0.73	$0.27

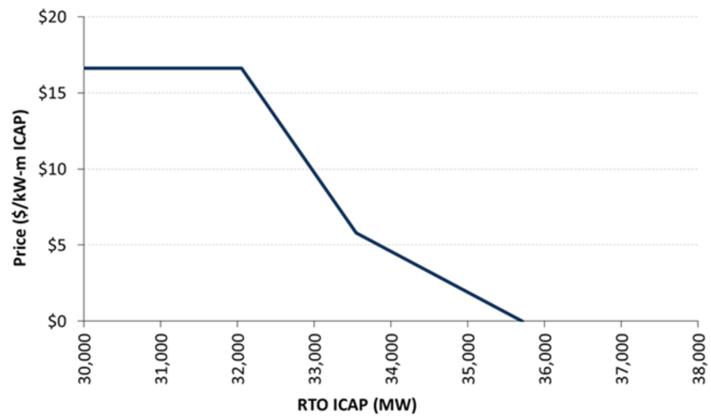

Figure 9: Demand Curve slope characteristics[28]

This sloped demand curve and the FCA 7 supply quantities were utilized to establish the forecast provided in Figure 8, since the FCA 8 quantities were not available at the time of the preparation of the forecast. The inclusion of the demand curve in our forecast denoted more stable prices for the future commitment periods without the price spike realized in FCA 8, which utilized a vertical demand curve.

5.4 REC Revenue

Several of PSNH's generating units currently qualify to produce renewable energy certificates (RECs) to satisfy renewable portfolio standards (RPS) in New Hampshire and other New England states. There are several classes of RECs in New England and each state has a slightly different definition of what qualifies for each class. PSNH has several facilities that qualify for Class I RECs, which are RECs for newer renewable energy facilities that came online or were modified after a certain date. [29] The following facilities currently qualify for Class I RECs for some or all of their output.

28 The proposed demand curve is modeled in three parts using FCA-7 MW quantities: the first one is constant and is equal to the price cap of 16.6/kW-m for the demand from 0 to 32,053 MW; the second is a linearly decreasing curve with a slope of $0.73kW-m per 100 MW from the cap to $5.8/kW-month for the demand from 32,053 to 33,545 MW- a change of $10.8 in price and 1,492 MW in quantity; and the third is a linearly decreasing curve with a slope of $0.27 kW-m per 100 MW from $5.8/kW-month to zero that spans from 33,545 to 35,711- a change of $5.8 in price and 2,166 MW in quantity.

29 In Rhode Island and Maine, the Class I-equivalent RPS tiers are labeled "New". For simplicity, this distinction in nomenclature is ignored here.

- Schiller 5
- Smith Hydro
- Burgess BioPower
- Lempster Wind

Just a few years ago, Class I regulations across the five New England states with RPS were similar enough that RECs became highly fungible across states and REC prices began to converge to a single New England price. However, individual states have made a number of recent changes that have reversed that convergence to a certain extent. Maine has qualified a number of existing biomass facilities under a looser interpretation of the “refurbishment” clause of its RPS, causing Maine Class I REC values to fall. Massachusetts has significantly tightened eligibility standards for biomass, effectively eliminating standalone (i.e. non-combined heat and power) biomass after a brief “grandfathered” period. New Hampshire recently reduced its alternative compliance payment (ACP) rate, which had been the same as Massachusetts and Rhode Island, to roll back past inflation adjustments and dampen inflation adjustments going forward. Long-term contracting requirements in Massachusetts and Rhode Island are reducing spot market REC transactions.

As a result of these recent changes, the price outlook for Class I RECs is not necessarily uniform across different resources. We assume that a third party buyer of any generation asset or PPA would seek out the highest value market for any RECs generated. Massachusetts Class I (“MA I”) is currently (and is projected to remain) the highest value REC market in New England due to its size, liquidity, strict eligibility standards (particularly regarding biomass) and high ACP. Lempster Wind and Smith Hydro RECs are eligible[30] for sale in MA I. The REC forecast applicable to these facilities is discussed in the following section. Schiller 5 and Burgess BioPower, on the other hand, will not be eligible for MA I after 2015, and their RECs will be less valuable than RECs from new wind or incremental small hydro. A separate forecast of Class I biomass RECs is discussed in Section 5.4.2 below.

5.4.1 Class I REC Forecast for Wind and Hydropower

Our forecast of Class I REC prices for wind and hydropower was created using La Capra Associates’ proprietary supply/demand model. The model uses publicly available regional load and system information from ISO New England, published information on renewable energy portfolio requirements in New England under current statute, and data on renewable resources already online to estimate REC market demand today and in the future. A supply curve is built up using our estimates of renewable potential and costs in the region. A market clearing REC price market price is calculated for each year of the forecast period. Although total supply and demand are aggregated across Massachusetts,

30 Smith Hydro would need to become certified by the Low Income Hydropower Institute (LIHI) prior to qualifying for MA I.

Connecticut, New Hampshire and Rhode Island Class I, the marginal REC is assumed to clear in the MA I market. Broker quotes were used for the first several years of the study period to ensure that the forecast was consistent with current market conditions.

This analysis assumes that the production tax credit is extended beyond current law, but phases out by 2020. Current New England renewable portfolio standards (RPS) policies, including scheduled changes in eligibility and increases in requirements, are assumed to continue through 2025.

RPS markets are subject to an unusual level of uncertainty because they are entirely a creation of public policy. Without long-term contracts for RECs, it is notoriously difficult for projects to be financed on the expectation of REC market revenues that can suddenly change at any time with a law or rule change. A buyer of a RPS-eligible facility would only count on a level of REC revenues that is financeable at the time of purchase such as through the execution of a long-term contract. REC contracts longer than 10 years are difficult to obtain, and beyond 2025 the policy and market uncertainty around REC revenues make it likely that revenue expectations would be heavily discounted. Adding to the policy uncertainty, our Reference Scenario assumes the implementation of a federal carbon program in 2020, which would provide additional net revenues to carbon-free renewable resources such as wind and solar. The presence of a significant carbon price makes it more likely that states would phase out RPS programs. Considering all of these risks and uncertainties, our Reference Scenario forecast declines to zero over 10 years from 2025-2034. The forecast is shown in the figure below.

[redacted]

Confidential Figure 10: Financeable Class I REC Forecast

5.4.2 Class I REC Forecast for Biomass Facilities

Biomass eligibility in RPS policies has been the subject of intense debate and sudden policy shifts over the last several years. For instance, Schiller 5 has been qualified as a Massachusetts Class I Generation Unit since 2006. In August 2012, however, Massachusetts finalized new regulations that would make it more difficult for biomass generation to qualify.[31] As of 2016, Schiller 5 will no longer qualify for Massachusetts RPS.[32] Connecticut has also taken steps to reduce biomass' role in its RPS. Public Act 13-303 directed the Commissioner of Energy and Environmental Protection to establish a schedule, beginning at the end of 2014, to assign reduced REC value to biomass and landfill gas facilities in the state's IRP process.

Massachusetts and Connecticut represent the large majority of REC demand in New England. If biomass is largely excluded from these markets, or included only at a steep discount, there is insufficient demand in other New England markets to absorb the large supply of RECs from qualified existing biomass plants. Biomass units would no longer be able to obtain the same prices for RECs as other Class I-eligible resources.

Viewed in this context, the PPA that PSNH just signed with Connecticut EDCs to sell [redacted] Schiller 5's RECs at [redacted] per REC for 10 years[33] is consistent with our Class I REC forecast discussed in the previous section. A recently-executed long-term contract for RECs is the best indicator of financeable REC revenue. Our Reference Scenario forecast starts with current broker quotes for Massachusetts Class I for 2015 (when Schiller 5 still qualifies in Massachusetts RPS), goes to the price of the Schiller 5/CT EDC PPA for 10-year term of the contract, and then declines thereafter for the same reasons of policy and market uncertainty described in the general Class I forecast. The forecast is shown in Confidential Figure 11 below. The projected New Hampshire ACP is also shown in the figure because it is assumed to be the ceiling on biomass RECs.[34]

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31 MA DOER Biomass Policy Regulatory Process website. http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/biomass/renewable-portfolio-standard-biomass-policy.html.

32 PSNH Response to LCA-032.

33 PSNH Response to LCA-062

34 Though Rhode Island has a higher ACP and still allows biomass eligibility, it is a relatively small market and partially relies on contracts signed pursuant to a Rhode Island renewable energy long-term contracting statute. We do not consider it likely that Burgess or Schiller 5 would be able to obtain a long-term contract in Rhode Island. Connecticut is also a market for biomass RECs, but its ACP is lower than New Hampshire's.

[redacted]

Confidential Figure 11: Class I Biomass Financeable REC Price Forecast

5.5 Ancillary Services Revenue

Power systems require ancillary services to maintain reliability and support their primary function of delivering energy to the customers. At ISO-NE the ancillary services are divided in the locational reserves market, which is comprised by the Locational Forward Reserve Market (LFRM) and the Real-Time Reserves Markets, and the regulation market. The LFRM is in place to procure off-line operating reserves, while the Real-Time Reserves Market compensates units for operating reserves needed in Real Time.

The main component of the LFRM is the Forward Reserve (FR) auction, which has an objective to procure enough off-line reserves to meet the Forward Reserve requirements for each reserve zone. PSNH has participated in the FR auction and has been obligated to provide Ten Minute Non- Spinning Reserves (TMNSR) in the Rest of the System (RoS) reserve zone. PSNH is utilizing the assets that have Claim 10 capability to meet this obligation since it stated that it does not engage in bilateral transactions. The following table depicts the assets that have Claim 10 capability:

[redacted]

Confidential Figure 12: PSNH Generation Assets' Claim 10 Capability

Historically, the FR Auction clearing price for RoS TMNSR zone has ranged between $3,300 $MW-month and $10800 $MW-month. The latest two auctions resulted in $5946 $MW-month and $8451 $MW-month due to revisions to ISO-NE market rules[35] that permit the procurement of additional TMNSR. We expect the Forward Reserve TMNSR prices to remain elevated and closer to the top of their historical range. The forecast for the RoS TMSNR Price is shown in the figure below:

[redacted]

Confidential Figure 13: Ten Minute Non-Spinning Reserves Price Forecast

In addition to the revenues realized from the Forward Reserve Auction, PSNH's assets are compensated for providing Real-Time Operating Reserves. For the past three years, PSNH averaged [redacted] per year in revenues from the Real-Time Operating Reserves market for the whole fleet.

35 FERC Docket No. ER13-465-000

6. COST ASSUMPTIONS

In this section, we describe our estimates of the costs of continued operation of the generation fleet. This is not applicable to the PPAs. These assumptions are developed to be consistent with the assumption that a Third Party Buyer would acquire the assets using non-recourse financing as described in the methodology section above. The costs are estimated for the continued operation of the units from January 1, 2015 through the end of their respective book lives.

6.1 Fuel Cost

A detailed discussion of the fuel price forecasts is contained in the NMM Report. For delivered prices at PSNH units, data provided by PSNH was relied upon. Coal price forecasts in the NMM, which otherwise rely on forecasts based on EIA's AEO, were adjusted based on short-term PSNH price projections[36]. The delivered price of natural gas at Newington, and all natural gas-fired plants in Northern New England, is adjusted from the Algonquin City Gates price based on PSNH's projection of transportation charges on the Portland Natural Gas Transmission System and the Maritimes & Northeast interstate gas pipelines.[37] The delivered biomass fuel cost is based on historical fuel cost data[38], periodic market surveys[39], and operating budgets for Schiller 5[40] provided by PSNH.

[redacted]

Confidential Figure 14: Select Delivered Fuel Price Forecasts for PSNH Units

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36 See PSNH Response to Liberty I-021.

37 See PSNH Responses to Liberty I-021 and Liberty II-013.

38 PSNH Response to LCA-003c

39 PSNH Response to Liberty I-022.

40 PSNH Response to Liberty II-005.

It is our understanding that none of the hydroelectric units are subject to any headwater benefits agreements or water use charges that would place a cost on water use beyond operation and maintenance expenses.

6.2 Operation and Maintenance

In addition to fuel costs, there are many other costs associated with running a generation asset. Many of these costs are referred to as operation and maintenance (O&M) expenses. O&M expenses are typically broken down into two main categories: variable O&M that is proportional to the level of energy production and fixed O&M that is incurred regardless of plant output. O&M expenses include materials needed to keep the plant running, such as reagents for the emission control equipment and computers for the control room, as well as labor costs associated with the personnel who operate and maintain the plant. Reference Scenario O&M expense estimates are based primarily on historical expenses at the plants[41] and PSNH budget projections for the next five years[42]. Sensitivities were also developed that tested alternative (typically lower) O&M assumptions based on comparison to public data from similar units. These O&M sensitivities are discussed in Section 8.2.

6.2.1 Fossil Plants

The variable and fixed[43] O&M expense data and projections for Merrimack, Schiller and Newington are shown in the figures below:

[redacted]

Confidential Figure 15: Merrimack Station O&M history and projections

41 PSNH Response to LCA-003 and LCA-020.

42 PSNH Response to LCA-035

43 PSNH refers to fixed O&M as "Direct" O&M.

[redacted]

Confidential Figure 16: Schiller Station O&M history and projections

[redacted]

Confidential Figure 17: Newington O&M history and projections

6.2.2 Hydro and Standalone CTs

White Lake and Lost Nation are aggregated with the hydro fleet in PSNH O&M budgeting[44]. The figure below shows the "hydro" (including White Lake and Lost Nation) fixed O&M expense data and projections. The Reference Scenario forecast assumes the 2018 O&M budget is held constant in real dollars, plus relicensing expenses as discussed in Section 6.5 below. Hydro units do not have any expenses considered variable expenses.[45] Net energy revenue was considered negligible in the DCF analysis of White Lake and Lost Nation, so no variable expenses were estimated.

[redacted]

Confidential Figure 18: Hydro units and Standalone CTs Combined O&M history and projections

To derive unit-specific O&M numbers, we allocated the total hydro budget proportional (less FERC relicensing costs) to each unit's capacity supply obligation. FERC relicensing costs were directly allocated to the relevant hydro unit.

6.3 Administrative and General

In addition to O&M expenses, there are also administrative and general (A&G) expenses associated with owning generation plants. PSNH categorizes these expenses as "allocated costs".[46] A&G expenses typically include overhead and other centralized corporate support costs, such as accounting and

44 PSNH Response to LCA-054.

45 PSNH Response to LCA-020

46 See PSNH response to LCA-020a, Attachment LCA 01-020a_updated.xlsx. The following explanatory note is offered regarding allocated costs: "These costs are included in Energy Service O&M costs but are not tracked on a unit or facility basis. The amount shown above is a total associated with the fleet and generation supply. These costs include indirect costs, overhead costs, uncollectables, etc. Some of these allocations remain, regardless of the utilization of the units."

budgeting, human resources, corporate managements, legal, environmental compliance, regulatory, etc. The Reference Scenario assumes continuing A&G costs in line with recent actual PSNH allocated costs. We assumed that each plant's share of fleetwide A&G expenses is proportional to its share of fixed O&M expense. Confidential Figure 19 below shows PSNH actual allocated costs and the Reference Scenario forecasts of A&G expense by major plant grouping.

[redacted]

Confidential Figure 19: PSNH Actual Allocated Costs and Reference Scenario A&G Forecast

6.4 Capital Expenditures

Capital expenditures refer to investments in physical plant that are capitalized and spread over a useful life of more than one year. Power plants generally require periodic capital expenditures to be maintained in good working order. Reference Scenario projections of capital expenditures necessary for the continued operation of the units through the study period are based primarily on historical capital additions at the plants and PSNH budget projections for the next five years[47]. Reference Scenario capital expenditure assumptions are shown with PSNH data and projections in the figures below. The Reference Scenario assumes that no station will be required to convert to a closed-loop cooling water system. A sensitivity case, discussed in Section 8.3, was developed for Merrimack that contemplates the potential necessity of adding a cooling tower.

47 PSNH Response to LCA-035, Attachment LCA 01-035 c and d.xlsx.

[redacted]

Confidential Figure 20: Merrimack Station Capital Expenditures History and Projections

[redacted]

Confidential Figure 21: Schiller Station Capital Expenditures History and Projections

[redacted]

Confidential Figure 22: Newington Capital Expenditures History and Projections

[redacted]

Confidential Figure 23: Hydro and Standalone CTs Capital Expenditures History and Projections

6.5 FERC Relicensing

For units that are assumed to obtain renewed FERC licenses during the study period, we assume that the cost of relicensing is about a million dollars (2015$), spread over the two years prior to the expiration of the current license. There is a fairly extensive series of studies, legal and administrative activity and other expenses that are a part of any relicensing process, regardless of the size of the unit. Eastman Falls costs related to its relicensing prior to the expiration of its current license in 2017 are included in PSNH budget projections, so no additional expense is assumed. Some of the smaller units may be able to spend less on relicensing, but on the other hand there is a risk in any relicensing process that FERC will require some kind of protection, mitigation and enhancement (PM&E) measure as a condition of relicensing. The million dollar cost estimate appropriately balances the downside risk that a streamlined license process will be less expensive and the upside risk that significant and unforeseen capital investment or operational changes will be required as a condition of relicensing.[48]

[48] In solving our DCF model for some of the smaller relicensing unit, the relicensing costs sometimes caused the debt coverage ratio to dip below 1.2. In these instances, if the DCR was sufficiently high in all other years the DCR test was waived on the theory that in actuality the expenses could be spread over more years or capitalized.

7. ALTERNATIVE SCENARIOS

Forecasting energy prices is an inherently difficult process due to the complex nature of energy markets and the uncertainty of key driver variables. Due to this uncertainty it is often helpful to construct additional scenarios that help illustrate the range of potential results. For the purposes of this valuation we selected several key variables and modeled non-reference values that present a reasonable range of future uncertainty in New England wholesale energy prices. The key variables we selected were:

- Delivered natural gas prices;
- Potential future federal carbon legislation;
- The potential for adding a new transmission project to import Canadian hydropower; and
- The potential for higher retirements (and subsequently higher capacity costs) in New England

Each scenario was modeled in the La Capra Associates NMM and yields a unique energy price and unit dispatch forecast. In addition, the High Retirements scenario yields a different capacity price and forward reserves price forecast. Specific inputs are described in more detail in the corresponding section of the NMM Report. The results were then processed using the DCF model discussed in Section 3.1.

7.1 High Gas

Our High Gas scenario is intended to represent a reasonable upper bound on the range of "50/50 forecast" outlooks among market participants. It is not intended to represent an extreme high scenario. Although we believe it is highly unlikely, some market participants may believe that the current pipeline congestion situation will never be alleviated, and that the basis differentials to New England observed in the last year is representative of the "new normal". Our High scenario forecast contemplates this potentiality by holding next year's annual average swap futures prices of close to $3.00/MMBTU constant in real dollars over the entire study period.[49] The High Gas scenario delivered price to New England at the Algonquin City gate is shown in Figure 2.

7.2 Low Gas

The Low Gas scenario is a converse of the High Gas scenario, and is intended to represent a reasonable lower bound on the range of "50/50 forecast" outlooks among market participants. It is not intended to represent an extreme low scenario. The Low scenario adopts the Reference scenario basis differential outlook, but takes a lower outlook on the Henry Hub price. We relied on the "High Oil and Gas Resource" alternative case from AEO2013, which assumes estimated ultimate recovery per shale gas,

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49 Futures price is a 3-month average quote for the February 2014 – January 2015 Clearport Algonquin City-Gates Natural Gas Basis Futures. Market data obtained January 14, 2014 through a service of GlobalView Software, Inc.

tight gas and tight oil well is twice as high as the reference case, and maximum well spacing is 40 acres. This case is representative of an optimistic view that the breakthroughs in supply from the last several years will continue to defy expectations. The Low Gas scenario delivered price to New England at the Algonquin City gate is shown in Figure 2.

7.3 No Federal CO_2 Price

The Reference scenario assumes that a federal program is enacted that places a cost on every ton of CO_2 emitted from fossil fuel-fired electric generating units. However, due to the significant amount of uncertainty concerning federal action on climate change, we have also considered a scenario in which no such program materializes. In the No Federal CO_2 Scenario, we assume that RGGI remains in place throughout the study period. Our forecast of CO_2 emission prices in this scenario relies on the RGGI study of the Updated Model Rule for prices through 2020, and then assumes that prices remain constant in real dollars thereafter.

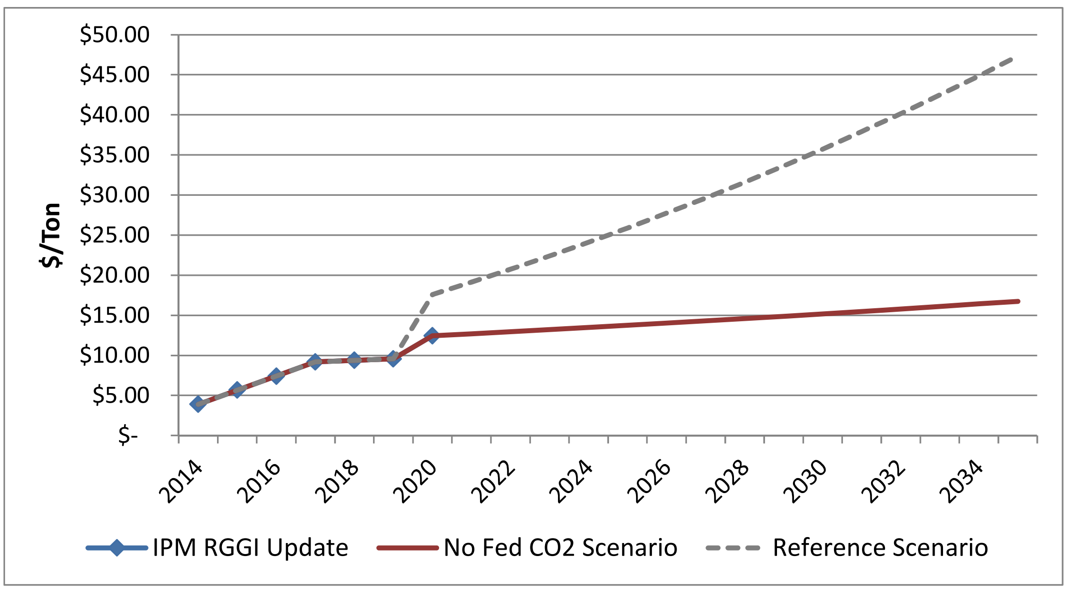

Figure 24: No Federal CO_2 Scenario carbon emission price forecast

7.4 No New Canadian Hydro Imports

The Reference Scenario assumes that a new transmission project is completed by 2019, adding 1,200 MW of transfer capability from Quebec to New Hampshire. The assumed project is representative of one of several proposals to construct new transmission to bring additional Canadian hydropower to New England. Any such proposal faces significant hurdles before it can be built, however, and is therefore subject to uncertainty. The No New Canadian Hydro Imports Scenario assumes that no additional transmission is added to bring Canadian power to New England over the study period. This scenario is found to have little impact on the asset and PPA valuations.

7.5 High Retirements

Generating unit retirements can be highly unpredictable – the recent surprise announcements concerning Vermont Yankee and Brayton Point serve to underscore the point. While many of the units being considered for retirement will not have large impacts on the wholesale energy market due to their already low capacity factors they will have an impact on the capacity markets. In addition to the potential for high retirements recent discussions in New England regarding potential new performance penalties and the possibility of high minimum offer requirements for certain renewable projects all point to the possibility of a need for capacity (and therefore higher capacity prices) in New England sooner than in our Reference Scenario.

In order to test the sensitivity of these potential impacts a thermal buildout was created that moved up the retirements of the remaining oil-fired units in New England, targeting a 45 year life as the trigger for retirement. Additionally, most new renewable capacity in New England was deemed to not bid into the capacity market, therefore creating a further gap that would need to be met by new thermal capacity.

The figure below shows the delta in cumulative retirements since 2013 for the High Retirement versus the Reference Scenario.

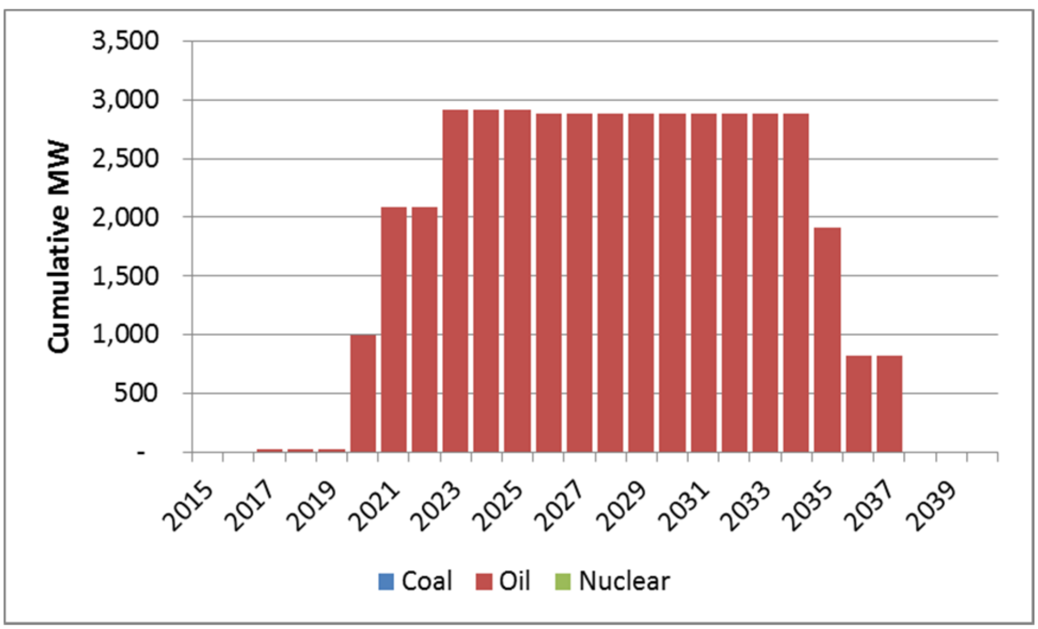

Figure 25: Cumulative Retirements Delta, High Retirements Scenario vs. Reference Scenario

The additional retirements in this scenario would affect both energy and capacity markets. We developed a high generator retirement FCM price forecast to better depict how an elevated rate of retirements will affect the FCM prices in the future. The figure below shows the FCM price forecast for the High Retirement scenario.

[redacted]

Confidential Figure 26: High Retirement Scenario FCM Price forecast.

8. SENSITIVITIES

This section describes sensitivities that were run for each unit.

8.1 REC Prices

For units and PPAs with significant REC revenue, the price of RECs is a major uncertainty in the DCF or mark-to-market analysis. We developed sensitivities that tested REC price forecasts that we view as the upper and lower bound of revenues that could reasonably be expected. The high and low REC price forecasts are described below.

8.1.1 General Class I (Smith Hydro and Lempster Wind)

For the high REC sensitivity, we assume that REC prices continue at ACP levels in Massachusetts, the largest Class I market with the highest ACP in New England. We project Massachusetts Class I ACP by escalating current ACP by inflation, as called for in the RPS. We subtract a 3% transaction cost to account for the added cost for obligated entities to procure RECs rather than simply pay the ACP rate.

The low REC sensitivity utilizes broker forward bid/offer quotes as far into the future as they are available on the assumption that a buyer could sell RECs forward at these prices at the time of the transaction[50]. Beyond current forward markets, the price is assumed to be zero.

The High and Low Sensitivity forecasts are shown with the Reference forecast in the figure below.

[redacted]

Confidential Figure 27: Reference, High and Low Class I REC forecasts

50 Broker bid/offer quotes taken from Marex Spectrometer reports.

8.1.2 Class I Biomass (Schiller 5 and Burgess BioPower)

The High and Low sensitivities for Class I Biomass were constructed on the same basic principles as the general Class I sensitivities. Since Massachusetts has effectively excluded biomass, however, we based our biomass REC sensitivity forecasts on New Hampshire Class I ACP and forwards. The sensitivity forecasts of RECs for Schiller 5 and Burgess BioPower are shown in the figure below. Note that Schiller is assumed to sell half its output at Connecticut contract prices in all scenarios and sensitivities regardless of the REC price forecast.

[redacted]

Confidential Figure 28: Reference, High and Low Class I Biomass REC forecasts

8.2 Operation and Maintenance Expense

Our reference case assumes that O&M expenses will continue in line with recent historical expenses and PSNH's projections for the next few years. However, it is reasonable that a buyer of the facility would expect to operate the plant at a different level of expense than the current owner. O&M expense sensitivities were developed for Merrimack, Schiller, Newington and the hydro units.

In order to develop alternative O&M cost sensitivities, we examined publicly available data on operating expenses at comparable units. When possible, we performed regression analyses to fit a statistical model for O&M expense based on key characteristics of the units. When no satisfactory statistical model could be fit to the data, judgment was used to determine an appropriate comparable value.

8.2.1 Merrimack Station

Coal-fired cyclone boiler units with heat input capacity similar to Merrimack 1 and 2 were identified by querying EPA Acid Rain Program emissions data.[51] Those units owned by regulated utilities that must file FERC Form 1 were identified as our comparable unit sample, shown in the table below.

EPA and FERC Form 1 data on the units was assembled into a database of recent reported O&M expenses and key plant characteristics, such as capacity, average generation, age, environmental controls and location. Average values from 2008 through 2011 were used, with dollar figures converted to real 2012 dollars. A multivariate linear regression analysis using the "least squares" method was performed to determine the best model for explaining average fixed O&M costs[52] using the independent variables in the comparable units database.

Table 2: Merrimack Comparable Units

Unit(s)	State	Utility	Capacity Input (MMBTU/hr)	Newest Unit COD	FGD?
Merrimack 1&2	*NH*	*PSNH*	*5,490*	*1968*	*Yes*
Tanners Creek 4	IN	Indiana Michigan Power Company	4,990	1964	No
Sibley 1-3	MO	KCP&L Greater Missouri Operations Company	7,307	1969	No
Michigan City Generating Station 12	IN	Northern Indiana Public Service Company	5,200	1974	No
R M Schahfer Generating Station 14	IN	Northern Indiana Public Service Company	5,200	1976	No
Muskingum River 3&4	OH	Ohio Power Company	4,300	1958	No
Kammer 1-3	WV	Ohio Power Company	6,468	1959	No
Coyote 1	ND	Otter Tail Power Company	5,280	1981	Yes
Big Stone 1	SD	Otter Tail Power Company	5,609	1975	No
Nelson Dewey 1&2	WI	Wisconsin Power & Light Company	4,679	1961	No
Edgewater (4050) 3&4	WI	Wisconsin Power & Light Company	5,823	1969	No

51 Retrieved from http://ampd.epa.gov/ampd/.

52 We assume that most variable O&M expenses are reported on the Form 1 under "Fuel expense". We derive fixed O&M numbers by subtracting fuel expense from total production expense.

The best model for Merrimack comparable units[53] was based only on total capacity in megawatts. The regression statistics and parameter details are shown in the tables below. An R-square value of 95% indicates that a high level of the variance in O&M expenses among the comparable units is attributable to the differences in the independent variable, capacity. The p-value indicates an extremely low probability (< 1%) that this relationship occurs by random chance. Note that coefficients are for millions of 2012 dollars. Since the model was calibrated using average 2008-2011 data, we interpreted model results to be 2010 O&M expenses, in millions of 2012 real dollars. Using Merrimack Station's combined winter rating of 482 MW, our statistical modeling predicts $18 million (2012$) in fixed O&M costs in 2010.

Table 3: Regression Statistics for Merrimack Comparable Unit O&M Regression Model

Statistic	Value
Number of Observations	10
R^2	95.9%
Adjusted R^2	95.4%
Standard Error	4.45
F-statistic	189
p-value	< 0.00

Table 4: Parameter details for Merrimack Comparable Unit O&M Regression Model

Parameter	Coefficient	Standard Error	p-value	Significance
Intercept	0.611	2.462	0.810	NS
Total Capacity (MW)	0.036	0.003	< 0.00	> 99%

The figure below shows how modeled values compare to actual O&M expenses for Merrimack and the comparable units. The chart shows that Merrimack expenses are well above those predicted by comparison to comparable units. We note, however, that none of our comparable units are located in the Northeast [54], and only one unit has a flue gas desulfurization (FGD, or Scrubber) system installed – two factors that could lead to materially higher O&M expense at Merrimack.

53 Note that Merrimack was not included in the sample for building the regression model.

54 Labor and some material costs are generally higher in the Northeast than in most other regions of the country.

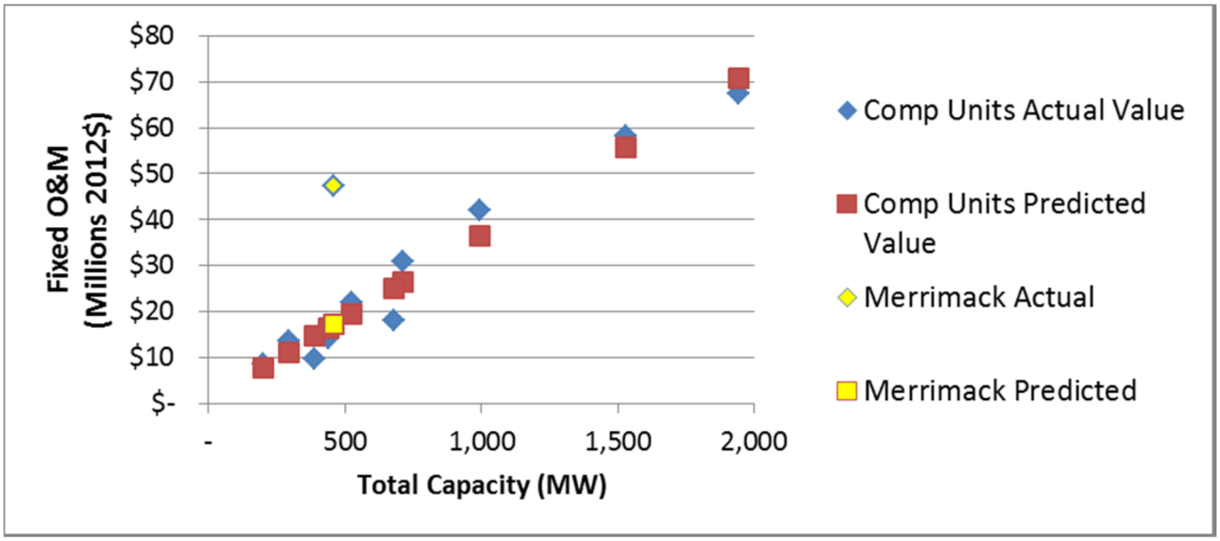

Figure 29: Modeled vs. Actual 2008-2011 Average Non-Fuel O&M Expenses for Merrimack and Comparable Units

We analyzed real dollar O&M expenses for the comparable units over time. The average compound annual growth rate in real (inflation-adjusted) dollars for the comparable units between 1998-2001 and 2008-2011[55] was over 2%. We conservatively assumed 1% real dollar growth in O&M expenses.

We also note that the FERC Form 1 O&M values likely do not include many administrative and general (A&G) expenses that would be incurred by the owner. PSNH classifies A&G expenses as "Allocated Cost", and at a fleet level these costs have ranged from [redacted] to [redacted] of PSNH generation's direct O&M expenses over the past six years.[56] Our comparable unit O&M assumes A&G expenses is just 15% of fixed O&M, in line with a more cost-competitive merchant generation owner.

The figure below shows our Comparable Unit O&M expense estimate in comparison to our Reference Scenario assumptions, which is based on a continuation of PSNH history and projections.

55 Four year averages were used to reduce the impact of year-to-year volatility in O&M expense on the long-term growth rate.

56 PSNH Response to LCA-020a, Attachment LCA-020a_updated.xlsx.

[redacted]

Confidential Figure 30: Merrimack Station Fixed O&M – PSNH history and projections, LCA Reference Scenario and Comparable Unit O&M Sensitivity

8.2.2 Schiller Station

The methodology used for Schiller Station was very similar to Merrimack. EPA Acid Rain Program data was queried to identify coal-fired plants like Schiller 4 and 6 with dry bottom wall-fired boilers, heat input capacity of less than 5,000 MMBTU/hr, and oil as secondary fuel. The table below shows the eight units most comparable to Schiller with accessible FERC Form 1 data.

Table 5: Schiller Comparable Units

Unit(s)	State	Utility	Capacity Input (MMBTU/hr)	Newest Unit COD	FGD?
Schiller 4&6	*NH*	*PSNH*	1,229	*1957*	*No*
Asheville 1&2	NC	Duke Energy Progress, Inc.	4,922	1971	Yes
Greene County 2	AL	Alabama Power Company	3,334	1966	No
H F Lee Steam Electric Plant 2&3	NC	Duke Energy Progress, Inc.	4,417	1962	No
Harbor Beach 1	MI	Detroit Edison Company	1,100	1968	No
Hoot Lake 3	MN	Otter Tail Power Company	1,163	1964	No
Scholz Electric Generating Plant 1&2	FL	Gulf Power Company	1,292	1953	No
W H Weatherspoon 1&2	NC	Duke Energy Progress, Inc.	1,400	1950	No
Wabash River Gen Station 2-5	IN	Duke Energy Corporation	4,150	1956	No

The best model for Schiller comparable units[57] was based on total capacity and net generation. The regression statistics and parameter details are shown in the tables below. An adjusted R-square value of 88% indicates that a high level of the variance in O&M expenses among the comparable units is attributable to the differences in capacity. The p-value indicates a low probability (< 1%) that this relationship occurs by random chance.

Table 6: Regression Statistics for Schiller 4&6 Comparable Unit O&M Regression Model

Statistic	Value
Number of Observations	8
R^2	91.4%
Adjusted R^2	88.0%
Standard Error	2.08
F-statistic	27
p-value	0.002

Table 7: Parameter details for Schiller 4&6 Comparable Unit O&M Regression Model

Parameter	Coefficient	Standard Error	p-value	Significance
Intercept	7.165	1.263	0.002	>99%
Net Generation (GWh)	0.010	0.003	0.013	>95%
Total Capacity (MW)	(0.028)	0.013	0.083	>90%

The figure below shows how modeled values compare to actual O&M expenses for Schiller and the comparable units. The chart shows that Schiller expenses are well above those predicted by comparison to comparable units. It is possible that other factors not considered in the regression analysis, including geographic location[58], could partially explain the difference between Schiller's modeled and actual O&M expenses.

57 Note that Schiller was not included in the sample for building the regression model.

58 O&M expenses can vary widely by location, particularly related to labor expense. New England has some of the higher labor costs in the country.

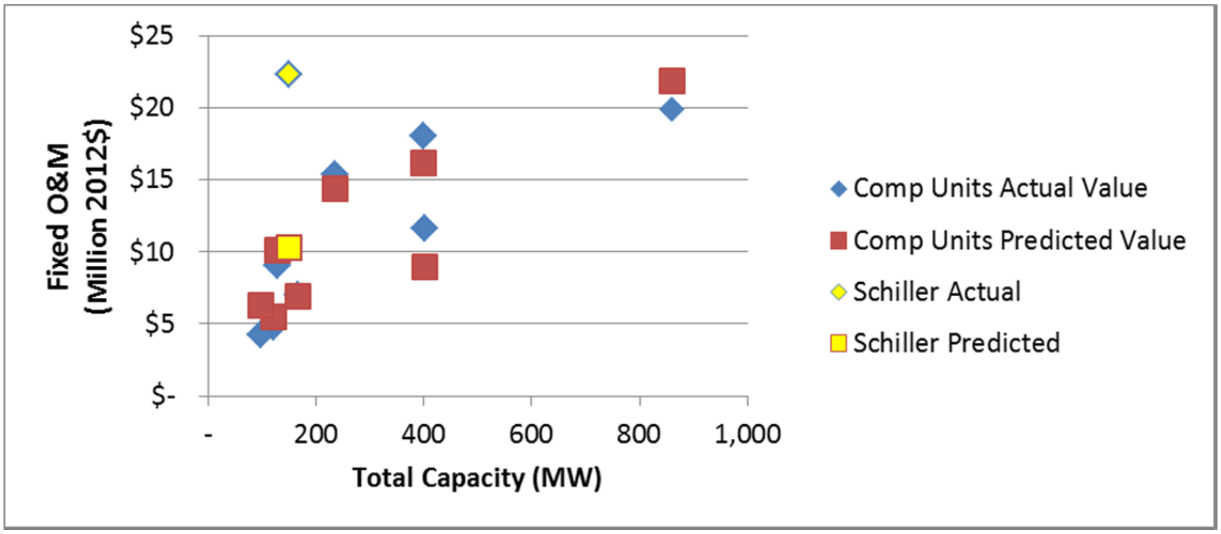

Figure 31: Modeled vs. Actual 2008-2011 Average Non-Fuel O&M Expenses for Schiller and Comparable Units

We analyzed real dollar O&M expenses for the comparable units over time. The average compound annual growth rate in real (inflation-adjusted) dollars for the comparable units between 1998-2001 and 2008-2011[59] was over 2%. As with Merrimack, we conservatively assumed 1% real dollar growth in O&M expenses, and added 15% A&G costs each year.

The figure below shows our Comparable Unit O&M expense estimate in comparison to our Reference Scenario assumptions, which is based on a continuation of PSNH history and projections.

[redacted]

Confidential Figure 32: Schiller Station Fixed O&M – PSNH history and projections, LCA Reference Scenario and Comparable Unit O&M Sensitivity

59 Four year averages were used to reduce the impact of year-to-year volatility in O&M expense on the long-term growth rate.

8.2.3 Newington

The same basic methodology was used for Newington as for Merrimack and Schiller. EPA Acid Rain Program data was queried to identify tangentially-fired boilers with residual oil as primary fuel. The table below shows the seven plants most comparable to Newington with accessible FERC Form 1 data. Six of the seven plants also burn natural gas, like Newington.

Table 8: Newington Comparable Units

Unit(s)	State	Utility	Capacity Input (MMBTU/hr)	Newest Unit COD	Dual Fuel?
Newington #1	*NH*	*Public Service of New Hampshire*	*5,470*	*1974*	*Yes*
Possum Point Power Station 5	VA	Virginia Electric & Power Company	8,486	1975	No
Yorktown Power Station 3	VA	Virginia Electric & Power Company	8,909	1974	Yes
Kraft 4	GA	Georgia Power Company	1,393	1972	Yes
Northport 1-4	NY	National Grid Generation LLC	15,500	1977	Yes
Port Jefferson Energy Center 3-4	NY	National Grid Generation LLC	3,948	1960	Yes
Anclote 1-2	FL	Duke Energy Florida, Inc.	11,200	1978	Yes
Suwannee River 1	FL	Duke Energy Florida, Inc.	460	1953	Yes

The best regression model found for Newington comparable units[60] was based on net generation. The regression statistics and parameter details are shown in the tables below. An adjusted R-square value of 81% indicates that much of the variance in O&M expenses among the comparable units is attributable to the differences in capacity. The p-value indicates a low probability (< 1%) that this relationship occurs by random chance.

60 Note that Newington was not included in the sample for building the regression model.

Table 9: Regression Statistics for Newington Comparable Unit O&M Regression Model

Statistic	Value
Number of Observations	7
R^2	84.4%
Adjusted R^2	81.3%
Standard Error	4.14
F-statistic	27
p-value	0.003

Table 10: Parameter details for Newington Comparable Unit O&M Regression Model

Parameter	Coefficient	Standard Error	p-value	Significance
Intercept	8.169	2.433	0.020	> 95%
Net Generation (GWh)	0.007	0.001	0.003	> 99%

The figure below shows how modeled values compare to actual O&M expenses for Newington and the comparable units. The chart shows that Newington expenses are well-aligned with those predicted by comparison to comparable units.

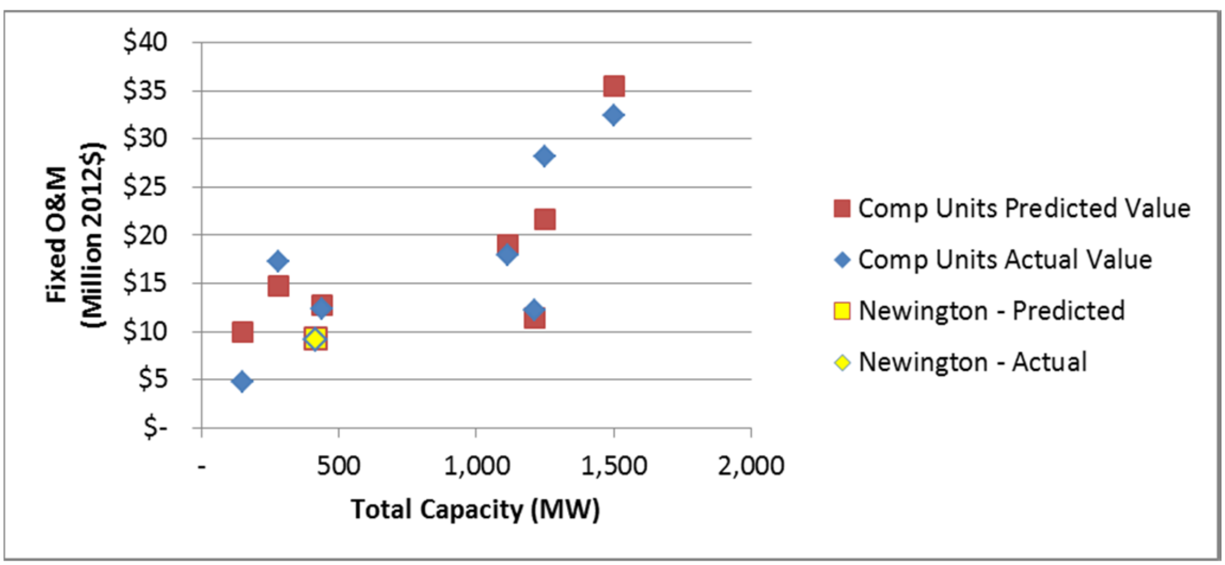

Figure 33: Modeled vs. Actual 2008-2011 Average Fixed O&M Expenses for Newington and Comparable Units

The figure below shows our Comparable Unit O&M expense estimate in comparison to our Reference Scenario assumptions, which is based on a continuation of PSNH history and projections. Newington is the only unit for which the Comparable Unit O&M scenario assumes higher O&M expense than the Reference Scenario.

[redacted]

Confidential Figure 34: Newington Fixed O&M – PSNH history and projections, LCA Reference Scenario and Comparable Unit O&M Sensitivity

8.2.4 Hydro Units

FERC Form 1 data was used to identify hydroelectric units with capacity of 20MW or less in New England and New York. The table below shows the 33 units with sufficient data to be added to our comparable unit O&M database.

Table 11: Hydro Comparable Units

Unit	Utility[61]	Capacity (MW)	Unit	Utility	Capacity (MW)
Salisbury	CVPS	1.3	Fairfax	CVPS	4.2
Cavendish	CVPS	1.4	Dashville	CVPS	4.8
Smith	CVPS	1.5	Marshfield Station #6	GMP	5.0
Glen	CVPS	2.0	Waterbury Station #22A	GMP	5.5
Carver Falls #11475	CVPS	2.2	Cadyville (A)	NYSEG	5.5
East Barnet #3051	CVPS	2.2	Mill "C" (A)	NYSEG	6.0
Silver Lake #11478	CVPS	2.2	Peterson	CVPS	6.4
Middlebury Lower	CVPS	2.3	Rochester Station #2	RG&E	6.9
Vergennes Station #9C	GMP	2.4	Essex Station #19B	GMP	7.2
Rainbow Falls	NYSEG	2.6	Milton	CVPS	7.5
Weybridge	CVPS	3.0	DeForge Station #1D	GMP	7.5
Clark Falls	CVPS	3.0	Kents Falls	NYSEG	13.6
Gorge Station #18	GMP	3.0	Stugeon Pool	CVPS	14.4
Rochester Station #26	RG&E	3.0	High Falls	NYSEG	15.0
High Falls (RoR)	CVPS	3.2	Ozark Beach	Empire	16.0
Middlesex Station #2	GMP	3.2	Mechanicville	NYSEG	18.1
Pittsford	CVPS	3.6			

Regression models were built on many of the same explanatory variables that were used in the thermal unit regression models. No model was found with the R-square or p-value statistics to indicate a satisfactory predictive model.

When average 2008-2012 total O&M62 expenses (2012$/kW) were charted against capacity (MW), we noted that the smaller units appeared to have more variability than the 10-20 MW units. Our Comparable Unit O&M sensitivity for hydro units uses the median value, in 2012$/kW, from the two size groupings (see Figure 35 below).

61 CVPS is Central Vermont Public Service (now part of GMP); GMP is Green Mountain Power Corporation; NYSEG is New York State Electric and Gas Corporation; RG&E is Rochester Gas and Electric Corporation; Empire is The Empire District Electric Company.

62 Note that for run-of-river hydro units, which generally have no significant variable O&M expenses, "total O&M" is functionally equivalent to "fixed O&M".

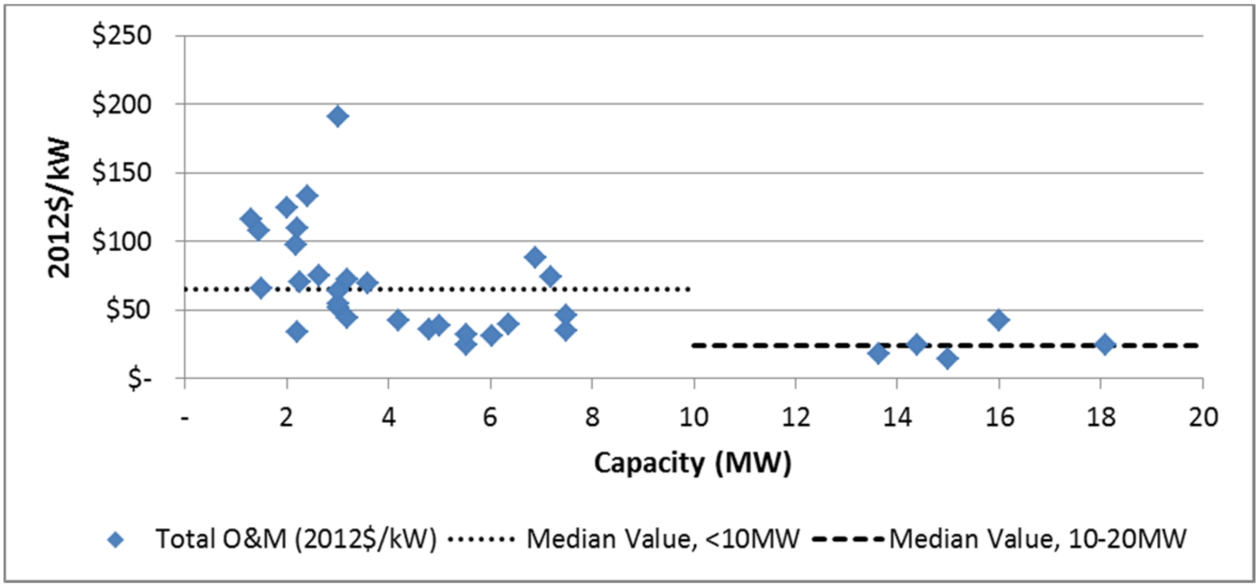

Figure 35: 2008-2012 FERC Form 1-reported Total O&M Costs for small northeastern hydro units (2012$/kW)

Applying the respective median values to the PSNH units, escalating 1% in addition to inflation, and adding 15% for overhead yields a forecast of O&M expense well below the Reference Scenario forecast.

[redacted]

Confidential Figure 36: Hydroelectric Units Combined Non-Fuel O&M – PSNH history and projections (excluding CTs), LCA Reference Scenario and Comparable Unit O&M Sensitivity[63]

63 PSNH History and Projections based on LCA analysis of PSNH responses to LCA-003 and LCA-035.

8.3 Environmental Compliance

In 2011, the EPA issued a draft National Pollutant Discharge Elimination System (NPDES) permit to Merrimack that required certain changes in compliance with the Clean Water Act. In particular, the draft permit required thermal discharge reductions of more than 99%, consistent with conversion to a closed-cycle cooling water system.[64] PSNH is vigorously contesting the draft permit, and a final permit has yet to be issued, but there is the potential that Merrimack would have to construct a water cooling tower at some point in the future as a condition of continued operation.

ESS conducted a review of PSNH's cost estimates and a review of the costs developed by the EPA[65] to develop an order of magnitude estimate of the overall cost to implement this technology. The major expenditures associated with the full conversion of Merrimack to a closed-loop cooling system are summarized in the ESS Report. In the Merrimack Cooling Tower sensitivity, we assumed that a cooling tower is added in 2019, adding additional capital expense and O&M expense as projected in the ESS report. Our analysis did not include potential lost capacity during construction, parasitic loss or operation loss due to the new cooling system.

64 http://www.epa.gov/region1/npdes/merrimackstation/

65 U.S. EPA. March 2011. *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule.*

9. FINANCING ASSUMPTIONS

9.1 Pro forma

The DCF analysis relies on a spreadsheet pro forma that is similar to the type of financial model used by owners and buyers of merchant generation assets. Projected revenues and expenses are entered for all years over the book life of each asset. The acquisition price and subsequent capital additions are financed according to the financing structure assumptions described below. Depreciation is calculated using standard IRS modified accelerated cost-recovery system (MACRS) schedules. The model solves for a value that provides the cash flow to equity sufficient to meet the target internal rate of return over the book life of the asset. The pro forma is set up to provide a valuation as of 12/31/2014.

9.2 Book life

Different length book life was assumed for different assets. A 15 year book life was assumed for all thermal generation. This is a reasonable time period because the age of the units, their high (unfavorable) position in the ISO-NE dispatch stack, and the capital requirements to extend life beyond this period make it unlikely that a buyer would place value on projected operation beyond 2029.

Hydroelectric assets tend to be longer-lived assets, so a longer book life was used. Most hydro units require a FERC license, which must be renewed every 30 – 50 years. The FERC license renewal process introduces a number of expenses, as well as the potential for capital investment and operational changes required by FERC as a condition of renewal. For this reason the expiration of a FERC license, when sufficiently far in the future, makes a natural breaking point for assumed book life of a hydro unit. We assumed that all units with current FERC licenses set to expire in the first 30 years would obtain a new 30-year license. Book life is expected to extend through the end of the last FERC relicensing, with a maximum of 40 years. The table below summarizes our book life assumptions for PSNH hydro units.

Table 12: FERC Relicensing and Book Life Assumptions for Hydro Units

Project	Current FERC License Expiry[66]	Assume Relicense?	Last Year in pro forma	Book Life
Eastman	12/31/2017	Yes	2047	33
Smith	8/1/2024	Yes	2054	40
Gorham	8/1/2024	Yes	2054	40
Ayers	4/29/2036	Yes	2054	40
Canaan	8/1/2039	Yes	2054	40
Amoskeag	5/18/2047	No	2047	33
Hooksett	5/18/2047	No	2047	33
Garvins Falls	5/18/2047	No	2047	33
Jackman	n/a*	n/a*	2054	40
Jackman does not need a FERC license.				

9.3 *Financial Structure*

We have assumed that the purchase of the generation assets by the Third Party Buyer would be financed using non-recourse financing with debt terms of 15 or 20 years. The financing assumptions were developed with commonly used methodologies. We used the build-up method from Morningstar's Ibbotson SBBI 2013 Valuation yearbook to calculate return on equity which is used as the internal rate of return for the valuation. This calculation is shown in the Table below and yields a return on equity of approximately 12%. This calculation is done as of January 2014.

Table 13: Build-up of Target Internal Rate of Return

Risk Free Rate	3.5%
Market Risk Premium	6.70%
Industry Risk Premium	-3.64%
10th decile size premium	5.00%
Calculated ROE	11.56%

We used the bond rate for Baa rated companies as of January 2014 plus a 2% adder because of the small size of the Facilities, which yields a return on debt of about 7.2%. We assumed a 55/45 debt/equity ratio based upon publicly available data on similar companies. We also assumed a marginal tax rate of 40 percent. The weighted average cost of capital (WACC) calculation is shown in the table below and yields a WACC of 7.8%.

66 FERC License information provided in PSNH Response to LCA-040.

Table 14: Weighted Average Cost of Capital Calculation

Source of Capital	Weight	Rate	After-Tax Rate	Weighted Component
Debt	55%	7.2%	4.3%	2.4%
Equity	45%	12.0%	12.0%	5.4%
WACC				7.8%

There were some circumstances in which a different financing structure was used. We assumed that debt would only be available if the pro forma analysis shows sufficient debt coverage ratios (DCR). The DCR is the earnings before interest, taxes, depreciation and amortization (EBITDA) divided by debt coverage payments (interest plus principal) in any given year. Most lenders want to see DCRs of at least 1.2 to provide assurance against default. If the initial acquisition value solved for in our DCF analysis yields DCRs in more than one year below 1.2, we assume that a lender would not be willing to make the loan equivalent to 55%. In such a case, we iteratively solved the model with reduced levels of debt until the value meets both internal rate of return on equity targets and the minimum DCR.

10. DCF VALUATION ANALYSIS RESULTS

Our DCF analysis uses a financial pro forma analysis for the postulated Third Party Buyer of the Facility, as described in the methodology section of this report (See Section 3). Our DCF analysis relies on a financial model which solves for a current asset value that provides the cash flow to equity sufficient to meet the target rate of return. All generation assets were analyzed under the Reference Scenario and each of the five alternative scenarios. In addition, assets were analyzed under a few specific sensitivities to test key uncertainties specifically related to each unit.

The range of DCF values obtained by running each scenario and sensitivity combination defines a potential range of values that each Facility could produce in these circumstances. This range provides an important basis for our opinion on market value, considering the risk judgments that would be made by the Third Party Buyer when purchasing the assets through a competitive process. Looking at the range of DCF values, we used judgment to conclude the value that best reflects the considerations of uncertainties and risks regarding each Facility's revenues and costs.

DCF results for each Facility are discussed in more detail below.

10.1 DCF Results – Merrimack Station

The results of the cases, shown in the table below, have 12/31/2014 current value outcomes ranging from a high of $159 million to a low of zero.[67] The Reference Scenario value is zero. EBITDA for each scenario and sensitivity are also shown in Figure 37 below. In the Reference and Low Gas scenarios, the EBITDA is not only insufficient to support ongoing financing expenses and additional capital expenditures; it is negative for most of the remaining life. In five of our six scenarios, projected cash flow for the plant is insufficient to provide a reasonable internal rate of return on equity at any price, so the DCF value is zero.

67 For the purposes of our DCF analysis, we assume a "floor price" of zero. It is possible for an asset value to go negative if cash flows are negative and retirement costs exceed land and salvage value. We did not attempt to quantify negative values in cases in which the pro forma model does not solve.

Table 15: Merrimack Station DCF Results Summary (2014$)

	Value ($Million)	Value ($/kW)
Scenario		
Reference	DNS*	DNS*
High Gas	$159	$362
Low Gas	DNS*	DNS*
No New Canadian Imports	DNS*	DNS*
No Federal CO_2	DNS*	DNS*
High Retirements	DNS*	DNS*
Sensitivities		
Comparable Unit O&M	$45	$101
Cooling Tower in 2019	DNS*	DNS*
Cooling Tower in 2019/High Gas Scenario	$111	$254
DCF-indicated Value	$0	$0
** DNS: Model does not solve due to negative cash flows*		

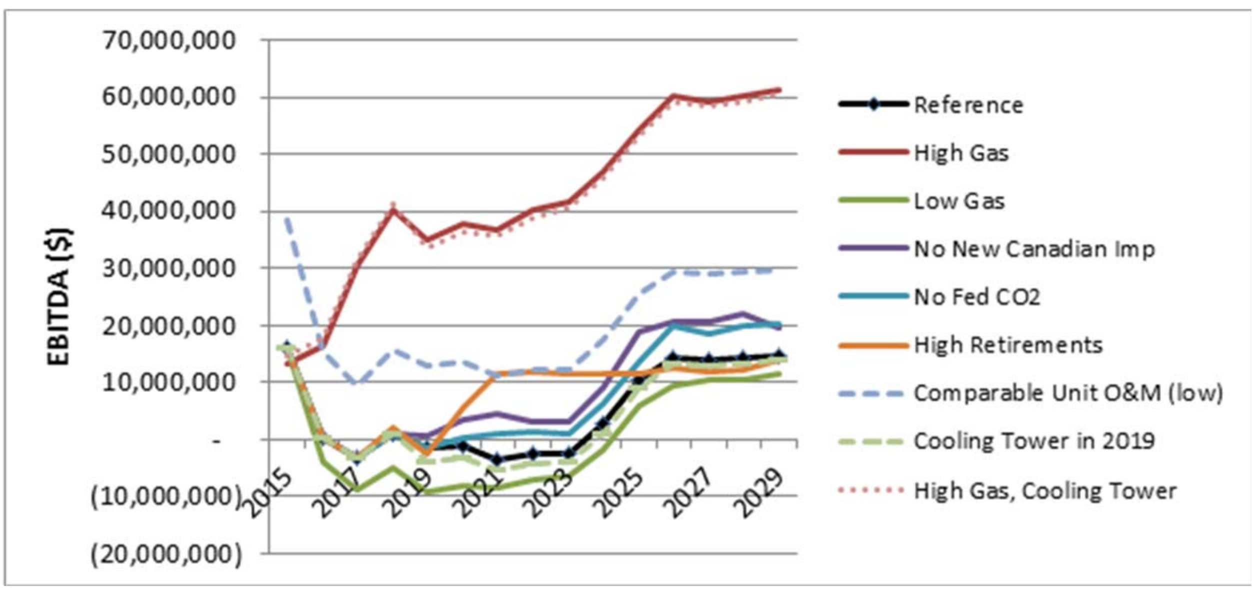

Figure 37: Merrimack Station Projected EBITDA for all scenarios and sensitivities

Based on the DCF results, we conclude that a Facility value of zero best reflects the considerations of uncertainties and risks regarding Merrimack revenues and costs. Although there are a few scenarios that yield positive value in the DCF, most scenarios show negative value. A third party buyer would look at the High Gas scenario and the Comparable Unit O&M sensitivity results as potential upside, but the lack of positive value in the Reference scenario or any of the other scenarios and sensitivities would discourage placing any value on projected cash flow.

10.2 DCF Results – Schiller Station

The results of the cases, shown in the table below, have 12/31/2014 current value outcomes ranging from a high of $36 million to a low of zero. The Reference Scenario value is zero. EBITDA for each scenario and sensitivity are also shown in Figure 38 below. In five of six scenarios, the EBITDA is not only insufficient to support ongoing financing expenses and additional capital expenditures, it is negative. In all six scenarios, projected cash flow for the plant is insufficient to provide a reasonable internal rate of return on equity at any positive or zero price, so the DCF value is zero. Schiller only shows any DCF value in the Comparable Unit O&M sensitivity.

Table 16: Schiller Station DCF Results Summary (2014$)

	Value ($Million)	Value ($/kW)
Scenario		
Reference	DNS*	DNS*
High Gas	DNS*	DNS*
Low Gas	DNS*	DNS*
No New Canadian Imports	DNS*	DNS*
No Federal CO_2	DNS*	DNS*
High Retirements	DNS*	DNS*
Sensitivities		
Comparable Unit O&M	$36	$258
High REC Price	DNS*	DNS*
DCF-indicated Value	$0	$0
** DNS: Model does not solve due to negative cash flows*		

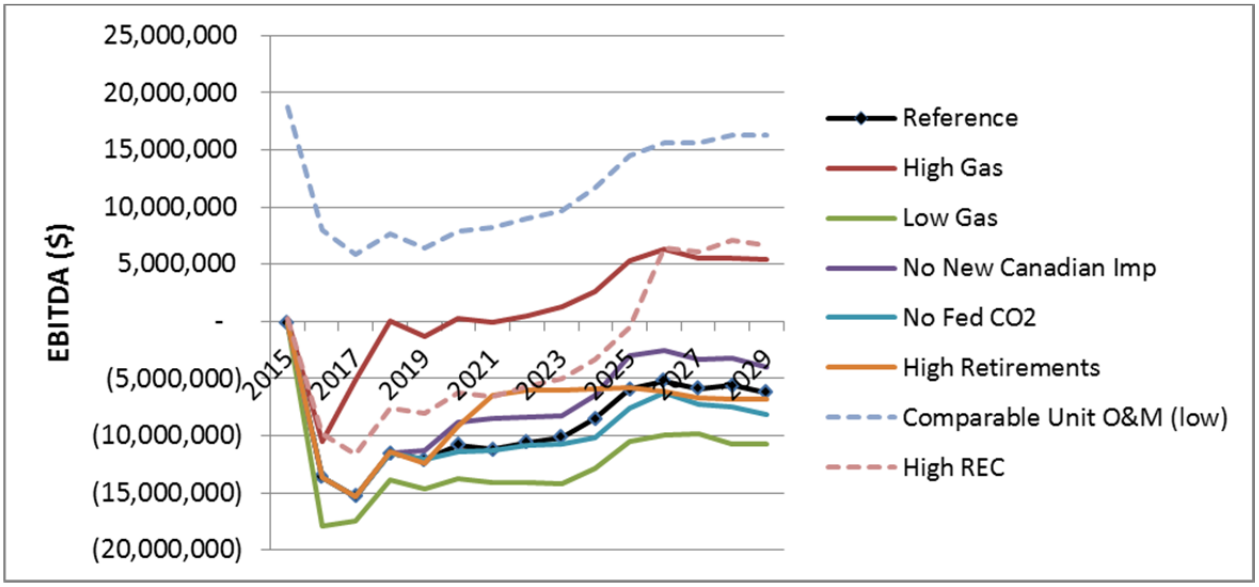

Figure 38: Schiller Station Projected EBITDA for all scenarios and sensitivities

Based on the DCF results, we conclude that a Facility value of $0 best reflects the considerations of uncertainties and risks regarding Schiller station revenues and costs. In no scenarios, and only modestly in the Comparable O&M sensitivity, does Schiller show positive value. A third party buyer would have no confidence that Schiller would provide reasonable, if any, return on equity at any price.

As an added sensitivity, we conducted an indicative DCF analysis of Schiller 5 operating as a standalone unit. For the purposes of the analysis, Schiller 5 was assigned a pro rata share of O&M and capital expenditures based on its contribution to the station's capacity supply obligation. The Reference Scenario DCF value for Schiller 5 under these simplifying assumptions is $8 million, primarily due to high REC revenues in 2015. This is largely a theoretical value, however, because it ignores the disposition of the other Schiller units. In any scenario where Schiller 5 is operated as a standalone unit as early as 2015, significant costs would be incurred to retire or mothball the other units, in addition to unwinding capacity supply obligations already cleared in the capacity markets. What this analysis may indicate is that a buyer who plans to redevelop the site for other purposes may be able to glean some residual value prior to retirement of the assets by scaling back O&M and capital investment and prioritizing operation of Schiller 5. This additional value is considered qualitatively in the reconciled value.

10.3 DCF Results – Newington Station

The results of the cases, shown in the table below, have 12/31/2014 current value outcomes ranging from a high of $103 million to a low of $79 million. The Reference Scenario value is $92 million. EBITDA for each scenario and sensitivity are also shown in Figure 39 below. Newington shows relatively steady value in all scenarios largely due to capacity revenues and low O&M costs. The unit runs very little, limiting its exposure to uncertainty in electric energy markets. Newington is the only fossil unit for which our comparable unit O&M analysis yielded higher rather than lower O&M projections. In this sensitivity, the value drops to $79 million.

Table 17: Newington DCF Results Summary (2014$)

	Value ($Million)	Value ($/kW)
Scenario		
Reference	$92	$229
High Gas	$90	$225
Low Gas	$93	$232
No New Canadian Imports	$101	$253
No Federal CO_2	$92	$229
High Retirements	$103	$258
Sensitivities		
Comparable Unit O&M	$79	$198
DCF-indicated Value	$90	$225

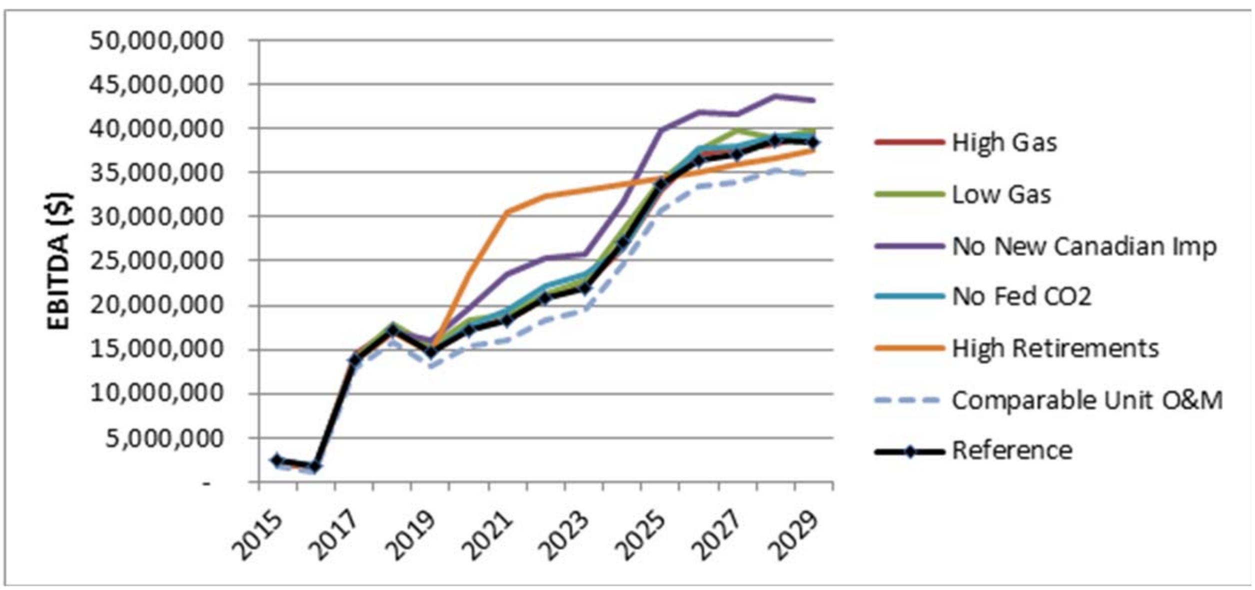

Figure 39: Newington Projected EBITDA for all scenarios and sensitivities

It should be noted that the DCF values for Newington are based on a less leveraged financing structure. When the model was solved at 55% debt financing, the debt coverage ratio (DCR) was quite low in the initial years, before shortage capacity prices began to increase revenues (and EBITDA). A level of debt in the 10-20% range was found in each scenario and sensitivity that allowed the model to solve for a value that would yield the target return without violating the DCR test.

Based on the DCF results, we conclude that a Facility value of $90 best reflects the considerations of uncertainties and risks regarding Newington revenues and costs.

10.4 DCF Results – Standalone CTs

The DCF results for both Lost Nation and White Lake fail to show positive value in any scenario. Since neither unit is assumed to participate in the energy markets in any significant way, only the High Retirements scenario differs meaningfully from the Reference Scenario for the standalone CTs. Projected EBITDA for the Reference and High Retirements scenarios are shown in Figure 40 and Figure 41 below. Based on the DCF results, we conclude that a value of zero best reflects the considerations of uncertainties and risks regarding Lost Nation and White Lake revenues and costs.

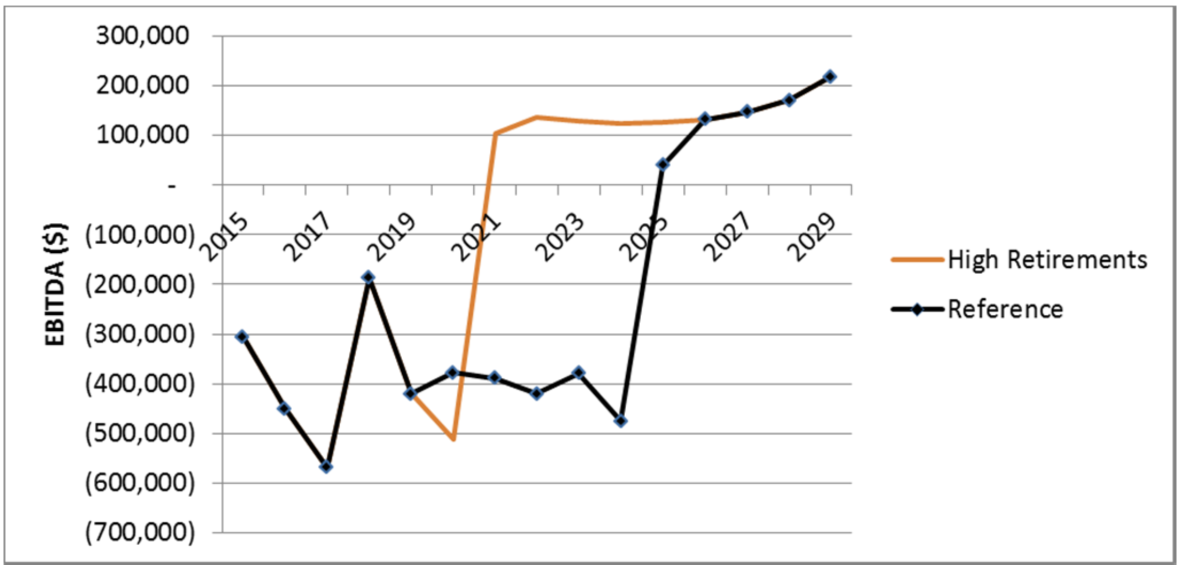

Figure 40: Lost Nation Projected EBITDA for Reference and High Retirements Scenarios

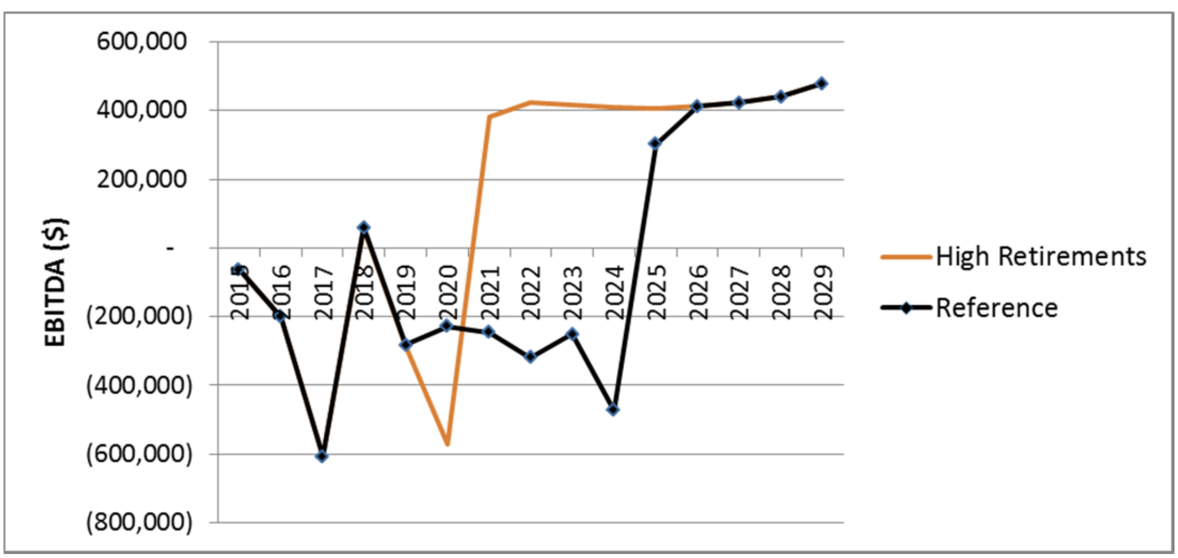

Figure 41: White Lake Projected EBITDA for Reference and High Retirements Scenarios

10.5 DCF Results – Hydro units

DCF models were constructed for each individual hydro resource (with the exception that Merrimack River Project units Amoskeag, Garvins Falls and Hooksett were combined), as well as all hydro units combined. The results for the combined hydro case were very close to the sum of the individual results. Results of the cases for each hydro unit are shown in the two tables below. Table 19 shows the results as dollars per kWh-year, a metric that is used in the comparable sales analysis and accounts for the fact that average output is a better indicator of value than capacity for hydro units.

The results of the cases for all hydro units have 12/31/2014 current value outcomes ranging from a high of $138.6 million to a low of $76.2 million. The Reference Scenario value is $112.4 million. Hydro combined EBITDAs for each scenario and sensitivity are also shown in Figure 42 below. The hydro units have consistently strong earnings and show high value across all scenarios.

Table 18: Hydro Units DCF Results Summary (Million 2014$)

	Value (Million 2014$)							
	Ayers	Canaan	Gorham	Eastman	Smith	MRP*	Jackman	Total
Scenario								
Reference	14.3	2.5	3.4	5.2	45.9	41.2	1.9	114.4
High Gas	18.8	3.2	4.7	7.6	58.1	56.9	3.2	152.5
Low Gas	9.5	1.7	2.3	3.2	34.8	26.6	0.9	79.0
No New Can Imp	14.9	2.6	3.6	5.4	47.7	43.2	2.0	119.6
No Fed CO_2	12.7	2.2	3.1	4.6	42.5	36.3	1.6	103.0
High Ret.	14.5	2.5	3.5	5.3	45.8	42.1	2.0	115.7
Sensitivities								
Comp Unit O&M	15.7	2.6	3.5	6.4	51.8	60.7	2.5	143.2
High REC	14.3	2.5	3.4	5.2	48.6	41.2	1.9	117.1
Low REC	14.3	2.5	3.4	5.2	43.1	41.2	1.9	111.6
DCF-indicated Value	14.5	2.5	3.5	5.5	47.0	45.0	2.0	120.0

** MRP: Merrimack River Project (Amoskeag, Garvins Falls and Hooksett)*

Table 19: Hydro Units DCF Results Summary (2014$/kWh-year)

	Value (2014$/kWh-year)							
	Ayers	Canaan	Gorham	Eastman	Smith	MRP*	Jackman	Total
Scenario								
Reference	0.32	0.34	0.29	0.20	0.41	0.29	0.20	0.32
High Gas	0.42	0.45	0.39	0.30	0.52	0.40	0.33	0.43
Low Gas	0.21	0.24	0.19	0.12	0.31	0.19	0.09	0.22
No New Can Imp	0.33	0.36	0.30	0.21	0.43	0.30	0.21	0.34
No Fed CO_2	0.28	0.31	0.26	0.18	0.38	0.25	0.16	0.29
High Ret.	0.32	0.34	0.29	0.21	0.41	0.29	0.21	0.33
Sensitivities								
Comp Unit O&M	0.35	0.35	0.29	0.25	0.47	0.42	0.26	0.41
High REC	0.32	0.34	0.29	0.20	0.44	0.29	0.20	0.33
Low REC	0.32	0.34	0.29	0.20	0.39	0.29	0.20	0.32
DCF-indicated Value	0.32	0.34	0.29	0.22	0.42	0.31	0.21	0.34

** MRP: Merrimack River Project (Amoskeag, Garvins Falls and Hooksett)*

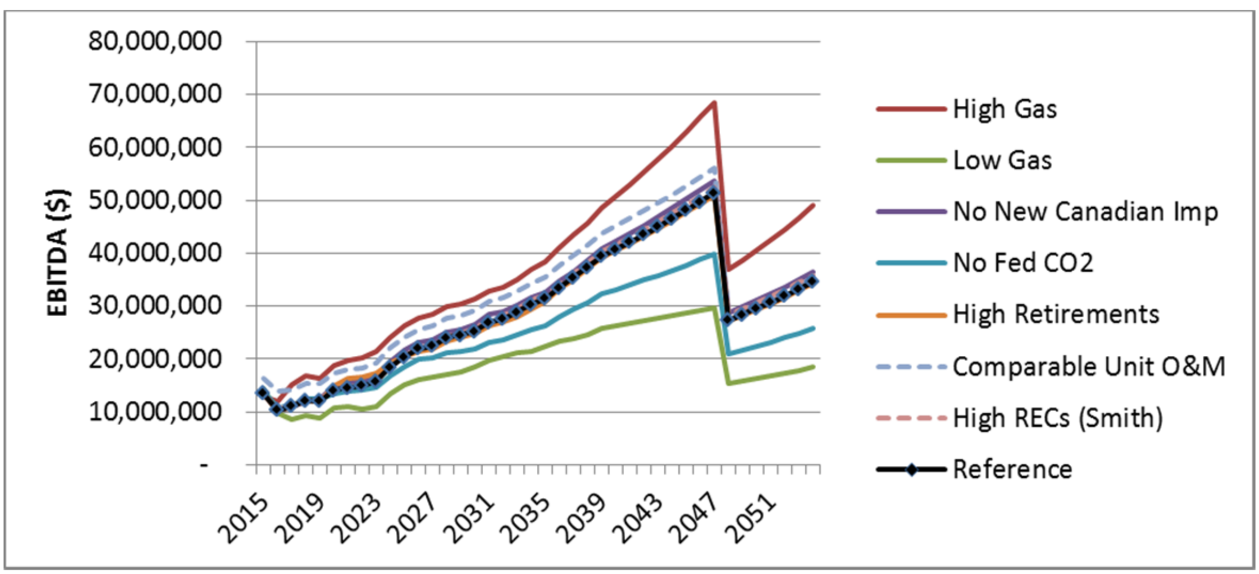

Figure 42: Combined Hydro Projected EBITDA for all scenarios and sensitivities

The drop in EBITDA is the result of some units reaching the end of their book lives in 2047.

The most important uncertainty for the hydro units is natural gas prices because they are primarily dependent on energy revenues but, unlike Newington, do not have increased fuel costs when natural gas prices —and LMPs —are high.

Based on the DCF results, we conclude that a combined value of $120 best reflects the considerations of uncertainties and risks regarding the hydroelectric units' revenues and costs.

11. COMPARABLE SALES ANALYSIS

11.1 Introduction

In order to supplement our DCF valuation analysis, we have reviewed sales of generating plants comparable to those in PSNH's portfolio. Our comparable sales analysis uses our survey of thermal and hydroelectric generator transactions over the past several years, as well as other market information. Information from the market on values placed on similar assets can provide additional evidence from which we can benchmark our DCF results. However, due to differences in timing, location, asset characteristics and financial circumstances for each transaction, comparable sales are of limited value in determining the value of a generation asset.

11.2 Hydroelectric comparable sales

11.2.1 Overview

La Capra Associates has reviewed recent market sales over the past eight years. We reviewed transactions occurring in the ISO-NE and have identified five sales occurring during that time period for which there is public information regarding the terms of the agreements. This represents a relatively small sample of asset sales which occurred over a period when energy markets in New England experienced significant volatility.

Hydroelectric generators are typically characterized by site specific attributes that have strong influence on the generation and value of the facilities. These attributes include unit type (run-of-river or impoundment), REC eligibility, FERC license status, location, land value, and associated on-site facilities (buildings, transmission, etc.).

Unlike thermal generation, hydro unit values are not compared on a maximum unit capacity basis. Due to the fact that most hydro units are largely non-dispatchable and that the average capacity factors vary widely between units, we have utilized a valuation metric that is based on average annual generation.

11.2.2 Description of sales

This section discusses the comparable sales we have identified and utilized for this analysis.

Sale 1: Brookfield-NextEra bundle

On December 21, 2012 Brookfield Renewable Energy Partners announced that it reached an agreement with NextEra Energy Resources to purchase NextEra's entire portfolio of hydro assets in Maine.[68] The sale was completed in March 2013.[69] In all, the sale included 19 generators totaling 351 MW and control of eight upstream storage reservoirs. Brookfield already owned existing hydro capacity of 103 MW on the same river systems, so the addition of these units, as well as the storage reservoirs, enhances the strategic value of the sale value to Brookfield due to their ability to integrate plant operations.[70]

The sale price was based on an enterprise value of $760 million, with Brookfield assuming $700 million in debt associated with the assets.[71] This essentially represents a transaction that is financed with at least 92% debt.

While the specific conditions and site-specific characteristics of the facilities vary, all plants were operational and had current FERC licenses at the time of the sale. Most were not due for relicensing for at least 10 years and some units had recently been modernized.[72]

Sale 2: Otter Creek/Center Rutland

In September 2011, Central Vermont Public Service (CVPS) purchased the Vermont Marble Division of Omya, Inc., including four hydroelectric plants with a combined capacity of 18.5 MW, associated assets, and service territory including approximately 900 customers.[73] The transaction was initially announced

68 "Brookfield Renewable Acquires 351 MW Portfolio of 19 Hydroelectric Facilities in New England." Brookfield Renewable Energy Partners, December 21, 2012. http://brookfieldrenewable.com/content/2012/brookfield_renewable_acquires_351_mw_portfolio_of_-36257.html

69 Notice of Consummation of Transaction. FERC Docket No. EC13-62, March 8, 2013.

70 "Brookfield Renewable Acquires 351 MW Portfolio of 19 Hydroelectric Facilities in New England." Brookfield Renewable Energy Partners, December 21, 2012. http://brookfieldrenewable.com/content/2012/brookfield_renewable_acquires_351_mw_portfolio_of_-36257.html

71 Id.

72 Id.

73 "CVPS completes purchase of Vermont Marble Power Division of Omya." Rutland Herald, September 2, 2011. http://rutlandherald.typepad.com/vermonttoday/2011/09/cvps-completes-purchase-of-vermont-marble-power-division-of-omya.html

in May 2010[74], and the initial transaction terms were modified in accordance with direction by the Vermont Division of Public Service. The final sale price included $28.25 million for the hydro plants. [75]

At the time of this transaction, the three facilities included in the Otter Creek Project were operational, and the Center Rutland project was not. CVPS purchased the assets with the intention of investing additional $15 million in capital to upgrade the facilities and increase the capacity by approximately three megawatts.[76] These upgrades could potentially allow the unit to receive Massachusetts Class II RECs for the incremental generation.

Sale 3: PPL-Black Bear Hydro bundle

PPL Corp. divested itself of all of its Maine hydro facilities in November 2009. It sold five facilities and its 50% ownership in a sixth to Black Bear Hydro Partners.[77] PPL concurrently sold three facilities to the Penobscot River Restoration Trust to be decommissioned.[78] As part of the bundle of transactions, FERC approved all the sales and provided provisional approval for the owners to increase capacity at some of the plants that remained in service.[79]

Black Bear Hydro Partners purchased the ownership interest in the six facilities totaling 29.5 MW for $81 million.[80]

Sale 4: Gilman Hydro

In December 2008 the Gilman Hydro Project was purchased from Dalton Hydro by Ampersand Gilman Hydro.[81] This hydro plant is at the site of the former Gilman paper mill, and the sale included the

74 "CVPS to buy Vermont Marble Power Division for $33.2M." The Barre Montpelier Times Argus, May 5, 2010. http://www.timesargus.com/article/RH/20100505/NEWS04/5050385/0/NEWS02

75 "Settlement Reached on CVPS Purchase of Vermont Marble Power Division of Omya." Central Vermont Public Service, March 2, 2011. http://www.marketwired.com/press-release/settlement-reached-on-cvps-purchase-of-vermont-marble-power-division-of-omya-nyse-cv-1404543.htm

76 "CVPS completes purchase of Vermont Marble Power Division of Omya." Rutland Herald, September 2, 2011. http://rutlandherald.typepad.com/vermonttoday/2011/09/cvps-completes-purchase-of-vermont-marble-power-division-of-omya.html

77 "PPL Corp. announces sale of 6 dams." Bangor Daily News, November 2, 2011. http://bangordailynews.com/2009/11/02/business/ppl-corp-announces-sale-of-6-dams/

78 "Great Works dam starts to come down Monday as part of effort to revive the Penobscot." Bangor Daily News,

79 "U.S. stimulus money to fund removing Maine's 8-MW Great Works Dam." HydroWorld, July 2, 2009. http://www.hydroworld.com/articles/2009/07/u-s--stimulus-money.html

80 "PPL Corp. announces sale of 6 dams." Bangor Daily News, November 2, 2011. http://bangordailynews.com/2009/11/02/business/ppl-corp-announces-sale-of-6-dams/

81 FERC Docket No. P-2392. Warranty Deed (dated 12/18/2008, filed with cover letter dated 5/15/2009).

associated mill buildings and equipment, including a non-functioning co-generation boiler. The hydro project has a total capacity of approximately 5 MW and the transaction price was $9 million.[82]

Sale 5: Rumford Falls

The oldest comparable transaction included in this analysis is the June 2006 purchase of the Rumford Falls facilities by Brookfield Power. This transaction included two units, the Rumford Falls Upper and Lower stations, which were formerly owned and operated by NewPage Corp., which operates a paper mill at the site. The combined capacity of the units is 41 MW, and the purchase price was approximately $144 million.[83]

11.2.3 Comparable sales indicative valuation

As previously discussed, hydroelectric plants are often subject to plant- and site-specific characteristics which influence the unit generation, and therefore value. Unlike thermal generators, which are typically valued on a $/kW basis, hydro units are valued based on generation. For this analysis, we use a metric calculated by dividing the sale price by the average annual generation of the unit(s) to yield a $/kWh-yr index. We have calculated the average annual generation using data for the five years prior to the year of the sale.

Based on this methodology, the sale values were calculated and are summarized in Table 20 below

82 "Ampersand Gilman energy purchases mill in Gilman." The Caledonian Record, August 5, 2008. http://caledonianrecord.com/Main.asp?SectionID=1&SubSectionID=1&ArticleID=40957

83 "Hydro power plants sold." Lewiston Sun-Journal, January 13, 2006. http://www.sunjournal.com/node/600772

Table 20: Comparable hydro asset transactions

Sale	Sale Date	Plant name(s)	Seller	Buyer	Sale Price (MM)	Capacity (MW)	Annual Generation (GWh)[84]	Sale Price ($/kWh-yr)
1	3/2013	19 hydro projects[85]	NextEra	Brookfield	$760.0	351.0	1,780,292	$0.43
2	9/2011	Otter Creek -Proctor -Beldens -Huntington Falls Center Rutland	Vermont Marble Power Division	Central Vermont Public Service	$28.25	18.1	76,218	$0.37
3	11/2009	Ellsworth Milford Stillwater Medway Orono West Enfield	PPL Maine	Black Bear Hydro Partners	$81.0	31.9	180,873	$0.46
4	12/2008	Gilman Hydro	Dalton Hydro	Ampersand Gilman Hydro	$9.0	4.9	19,145	$0.47
5	6/2006	Rumford Falls	Brookfield	NewPage Corp.	$144	41.3	284,794	$0.51

The trend of sale prices exhibit a general decline over time, and the most recent sale, at $0.43/kWh, was a high value asset with multiple plants and storage reservoirs that integrated well with existing assets of the buyer. There were also unique financing circumstances that may have contributed to a higher sale price for the Brookfield/NextEra transaction (Sale 1).

The older sales are of extremely limited utility for shedding light on value of a transaction now. The outlook on energy markets has undergone a fundamental shift since 2006-2008 that would be impossible to adjust for quantitatively. The figure below shows the changes in Henry Hub natural gas spot prices and AEO long-term forecasts since 2009. Hydro assets, which rely primarily on energy prices (which would be strongly correlated with natural gas prices), have been hit hard by these falling markets.

84 Generation based on EIA Form 923 data.

85 Androscoggin 3, Azischohos, Bar Mills, Bates Mill Upper, Bonny Eagle, Brunswick, Cataract, Charles E Monty, Continental Mills, Deer Rips, Gulf Island, Harris, Hill Mill, Hiram, North Gorham, Shawmut, Skelton, West Buxton, Weston, Williams and Wyman Hydro. The total plants listed here (21) differs from the 19 plants cited in press coverage of the transaction because in some instances a hydro project consists of multiple plants.

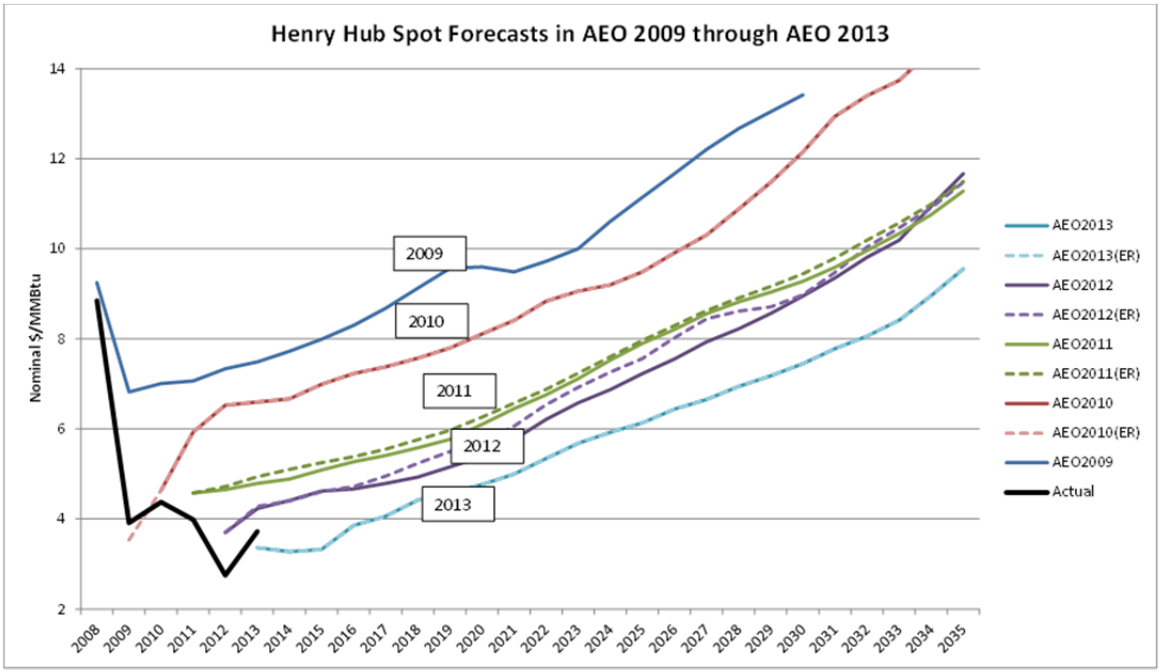

Figure 43: Henry Hub Spot Prices and AEO Forecasts, 2008-2013[86]

Based on these results, we have determined that a reasonable indicative range of values is $0.35/kWh - $0.45/kWh, without adjusting for market changes over the past 3-4 years or unique characteristics of the transactions.

11.2.4 Reconciliation of Brookfield/NextEra Sale with DCF Reference Scenario

The Brookfield/NextEra transaction is the only sale in our sample to have occurred within the last few years. On its face, it would seem to indicate by its higher price that the market for hydro assets has rebounded since the previous transaction in 2011. However, it is our belief that advantageous financing may have inflated the purchase price above what would be reasonable to assume for a hypothetical sale of PSNH assets.

As mentioned above in the description of the Brookfield/NextEra sale, the sale price of $760 million included $700 million in assumed project debt, or 92% of the total price. The sale price index of the Brookfield/NextEra transaction was $0.43/kWh-year, well above our DCF-indicated value of PSNH hydro units of $0.34/kWh-year and our Reference Scenario DCF value of $0.32/kWh-year. If we make adjustments to our Reference Scenario DCF model to approximate the Brookfield finance structure, and assume no REC revenues (none of the NextEra units were eligible for premium RECs), the acquisition price for PSNH's hydro fleet would be $0.44/kWh-year (See Table 21 below).

[86] Source: U.S. EIA data. Annual average spot prices obtained through GlobalView Software, Inc.

Table 21: Brookfield-comparable DCF Results

	Reference	Reference with 92% debt; No RECs
	$/kWh-year	
Ayers Island	0.32	0.45
Canaan	0.34	0.47
Gorham	0.29	0.40
Eastman Falls	0.20	0.30
Smith	0.41	0.51
Merrimack River Project	0.29	0.40
Jackman	0.20	0.30
PSNH Hydro Total	0.32	0.44
Brookfield/NextEra Transaction	*n/a*	*$0.43*

This analysis is further evidence that the Brookfield/NextEra sale should be used only as an upper bound on the value of PSNH assets, if at all.

11.2.5 Discussion and Conclusions

This evaluation of comparable hydroelectric sales provides a useful indicator of the market value of the assets, but it is important to note the limitations of this analysis. Any market transaction contains individual factors related to the parties, the asset, and the timing which impact the final sale price and conditions. These factors could include buyer/seller motivations, condition of the asset, additional components of the transaction (transmission, buildings, land, water rights, etc.), control of reservoirs, presence of PPAs, and REC eligibility, among many others.

In addition to these site-specific factors, a major driver of sale value is the outlook of energy markets at the time of the sale. The comparable sales identified in our analysis transacted between 2006 and 2013. During that time, energy markets in New England experience significant volatility. Since hydro assets derive the majority of their value from energy sales, the energy price forecasts contemporaneous with the transactions are key variables.

It is not possible to adjust for all the sale- and asset-specific factors to arrive at a completely comparable sale value. Rather than attempt to adjust for all these factors, we have used the comparable sales analysis as an indicative range of what valuation the market could assign to the hydro assets.

Based on the foregoing analysis, we estimate that a reasonable indicative range of market values for the hydro assets is between $0.35 and $0.45/kWh-yr. This range corresponds to a value of between $124 and $159 million for PSNH's assets. However, a closer examination of the comparable sales indicates that this range is more likely an upper bound rather than a direct indicator of value for PSNH hydro assets.

11.3 Natural Gas and Oil-fired generation comparable sales

La Capra Associates reviewed recent market transactions for natural gas- and oil-fired power plants in New England to identify sales of units comparable to Newington Station. Our research did not identify any recent sales of units of large scale peaking units like Newington.

11.4 Coal generation comparable sales

11.4.1 Overview

Similar to the evaluation of market transactions for the hydro assets, we have reviewed market conditions for transactions involving coal-fired power plants in New England. There are few operational coal plants remaining in New England, and there have been several recent announcements of retirements planned in the coming years. The following section reviews that status of coal plants in New England and discusses related transactions.

11.4.2 Description of plant status

Brayton Point

The most recently transacted coal plant in New England is Brayton Point in Somerset, Massachusetts. Dominion Power sold Brayton Point to EquiPower, a subsidiary of the private equity firm Energy Capital Partners, in August 2013. The sale was part of a bundled transaction with two other Dominion plants in Illinois, a total of nearly 3,000 MW for a total purchase price of $472 million.[87] Despite a recent investment of approximately $1 billion in environmental upgrades, including new cooling towers and emissions scrubbers, the new owners announced that the plant would close in 2017. This announcement was made despite the changes to the Forward Capacity Market that will result in significantly higher capacity prices in 2017.[88] The table below presents a timeline of events regarding the Brayton Point transaction and closure.

As with all bundled sales, it is difficult to determine the exact portion of the sale value assigned to Brayton Point. However, the fact that the new owner of Brayton Point so quickly announced that it would retire the plant indicates that it was likely not a significant portion of the total sale value. It has

87 "FERC approves sale of Somerset's Brayton Point power plant." Herald News, August 20, 2013. http://www.heraldnews.com/x511615161/FERC-approves-sale-of-Brayton-Point-power-plant

88 "EquiPower to shut Brayton Point, Mass. Coal power plant in 2017." Reuters, October 8, 2013. http://www.reuters.com/assets/print?aid=USL1N0HY1D920131008

been estimated that Brayton Point's value was only $50-$55 million.[89] The June 2013 report by NHPUC Staff and Liberty cited an estimate of $35/kW which falls into that range.

Table 22: Timeline of Key Events Related to Brayton Point

Date	Event
August 2013	Brayton Point sold by Dominion Power to EquiPower in a bundle with two Illinois plants
October 2013	Brayton Point announces closure
December 20, 2013	ISO-NE rejects Brayton Point's Non-Price Retirement Request, citing reliability need[90]
January 24, 2014	FERC approves ISO-NE's revisions to the Forward Capacity Market, which will result in significantly higher capacity prices in 2017
January 27, 2014	Brayton Point confirms that, regardless of the ISO-NE decision and the potential for higher capacity prices, the plant will cease operations as of June 1, 2017[91]

Salem Harbor

The Salem Harbor coal plant was sold to Footprint Power in August 2012. The terms of the sale are not publicly available. When the sale was completed, two of the four units had been retired (in December 2011), and the other two were already scheduled for retirement in June 2014.[92]

Footprint Energy purchased Salem Harbor with the intention of redeveloping the site with a new natural gas plant. The site needs significant remediation that will require an investment of $50-$75 million.[93] This transaction does not provide a data point for determining the market value of the PSNH assets, but does provide further evidence of the minimal value of coal units in New England since this transaction was essentially for the site and not the plant.

Bridgeport Harbor 3

Other than the PSNH plants, Bridgeport Harbor is the only coal plant in New England that is not scheduled to be retired or delisted. However, the annual capacity factor for the Bridgeport Harbor plant has been declining in recent years, operating at only 3% in 2012 at the low point for gas prices, and

89 "New owners to shutter outmoded Brayton Point Power Station in 2017." Providence Journal, October 8, 2013. http://www.providencejournal.com/breaking-news/content/20131008-new-owners-to-shutter-outmoded-brayton-point-power-station-in-2017.ece

90 "Grid operator ISO New England rejects Brayton Point closure bid." Herald News, January 4, 2014. http://www.heraldnews.com/x920322292/Grid-operator-ISO-New-England-rejects-Brayton-Point-closure-bid?zc_p=1

91 "'Must run' coal plant to shut down in 2017." Boston Globe, January 27, 2014. http://www.boston.com/business/2014/01/27/must-run-coal-plant-shut-down/IOHvxOCKsKJcNkr5z74mGN/story.html

92 "Purchase of Salem Harbor Power Station completed." Boston Globe, August 6, 2012. http://www.boston.com/yourtown/news/salem/2012/08/purchase_of_salem_harbor_power.html

93 Id.

rebounding only to 20% in 2013.[94]

Mount Tom Station

In March 2013, ISO-NE approved the application by GDF Suez, owner of the Mount Tom plant in Holyoke, Massachusetts, for a dynamic de-list bid for 2016. The significance of that approval is that Mount Tom will no longer receive capacity payments or be required to run. The plant may still run and sell energy to the wholesale market, but the de-list allows the plant to retire altogether if it is no longer economic to run.[95]

AES Thames

The 181 MW AES Thames plant ceased operation in January 2011 and filed for bankruptcy soon after. The plant was purchased for $2.35 million at auction in December by a salvage company that decommissioned the plant.[96]

Somerset 6

The Montaup/Somerset Station coal plant was retired by NRG in 2010.[97]

11.4.3 Discussion and Conclusions

The foregoing review of the status of coal plants in New England demonstrates that the market for coal plants is very limited. There have been two recent transactions for coal plants. Salem Harbor was purchased with the explicit purpose of retiring it and redeveloping the site, so the purchase price (which is not public knowledge) was essentially for the land and the proximity to infrastructure. In the other transaction, the buyer of Brayton Point almost immediately announced the closure of the plant after the plant was complete, indicating that the other two plants included in the bundled transaction represented the majority of the value to the buyer.

Due to the multiple recent retirements and financial conditions of other coal plants in New England, the estimated value of the Brayton Point plant at $35/kW should therefore be considered a maximum comparable value for PSNH's coal units, and it is questionable as to whether they would have any value to potential buyers at all.

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94 Source: U.S. EIA Form 923 data.

95 "Mount Tom Power Station in Holyoke has no plan to close, official says." The Republican, June 25, 2013. http://blog.masslive.com/breakingnews/print.html?entry=/2013/06/mount_tom_power_station_has_no.html

96 "Sale of AES Thames 'devastating' for Montville." The Day, December 13, 2011. http://www.theday.com/apps/pbcs.dll/article?AID=/20111213/nws01/312139923/1017

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12. MARK-TO-MARKET ANALYSIS

The Mark-to-market (MtM) analysis of the PPAs compares the products purchased and the payments made to purchase those products to the market value of those purchased products. If the PPA payments are expected to be less than the market value of the products, then the PPA is considered to be “below market” and would therefore have a positive valuation. If the PPA payments exceed the market value of the products purchased, the PPA is considered to be “above market”, and would have negative value.

Our MtM analysis was conducted using spreadsheet models of the anticipated contract payments and market replacement value over the remaining terms of the contracts. The value of the contracts is the net present value (NPV) of the MtM gains or losses. Since there is no physical asset associated with the sale of a PPA, we assume any transaction would be a completely unleveraged cash transaction. We therefore use our return on equity of 12% as the discount rate in the NPV analysis.

Our market value projections and contract payment estimates (to the extent they are tied to market price indices) are derived from the same market forecasts for all of the scenarios as well as the High and Low REC price sensitivities that were used in the DCF analysis.

Results for the two PPAs are presented in the following sections.

12.1 Burgess BioPower PPA

The table below shows the projected NPV of MtM gains (positive) or losses (negative) for the Burgess BioPower PPA under our market scenarios and sensitivities. The results are broken out by the three products delivered under the PPA: energy, capacity, and RECs.

The MtM analysis shows that the Burgess BioPower PPA is likely to lose anywhere from $25 million to $189 million relative to market-based replacement products over the last 19 years of the contract. REC purchases are projected to produce the majority of those losses, in part because contract pricing formulas are based on a New Hampshire Class I ACP formula that has subsequently been reduced substantially. The contract energy price is also substantially higher than our forecasts in all scenarios, including the High Gas scenario. As noted in the Comparable Sales discussion, this is consistent with the substantial decline in energy market price outlooks since 2011, when the PPA was approved.

Table 23: NPV Gain/(Loss) on Burgess BioPower PPA by scenario/sensitivity (Million 2014$)

Scenario/Sensitivity	NPV Gain/(Loss) @ 12% discount rate (Million 2014$)			
	Energy	Capacity	RECs	Total
Reference	(54.8)	9.7	(83.2)	(128.3)
High Gas	(15.5)	9.7	(83.2)	(89.0)
Low Gas	(65.1)	9.7	(83.2)	(138.6)
No New Canadian Imports	(52.5)	9.7	(83.2)	(126.0)
No Federal CO_2	(56.9)	9.7	(83.2)	(130.4)
High Retirements	(55.4)	13.5	(83.2)	(125.1)
High RECs	(54.8)	9.7	19.8	(25.3)
Low RECs	(54.8)	9.7	(143.5)	(188.6)
Final MtM Valuation: ($125)				

Based on the MtM results, we conclude PSNH would need to pay a third party $125 million to accept assignment of PSNH's rights and obligations under the Burgess BioPower PPA.

12.2 Lempster Wind PPA

The table below shows the projected NPV of MtM gains (positive) or losses (negative) for the Lempster Wind PPA under our market scenarios and sensitivities. The results are broken out by the three products delivered under the PPA: energy, capacity, and RECs.

Table 24: NPV Gain/(Loss) on Lempster Wind PPA by scenario/sensitivity (Million2014$)

Scenario/Sensitivity	NPV Gain/(Loss) @ 12% discount rate (Million 2014$)			
	Energy	Capacity	RECs	Total
Reference	(1.0)	0.2	5.9	5.1
High Gas	(0.1)	0.2	5.9	6.0
Low Gas	(3.2)	0.2	5.9	2.9
No New Canadian Imports	(0.8)	0.2	5.9	5.3
No Federal CO_2	(1.2)	0.2	5.9	4.9
High Retirements	(1.0)	0.2	5.9	5.1
High RECs	(1.0)	0.2	8.5	7.8
Low RECs	(1.0)	0.2	(2.1)	(2.8)
Final MtM Valuation: $5				

The MtM analysis shows that the Lempster Wind PPA is slightly below market in all but the Low REC sensitivity, and only slightly above market in that sensitivity. The results are to be expected since the contract has floating energy and capacity prices tied to a percentage of actual market prices.

Based on the MtM results ranging from a loss of $2.8 million to a gain of $7.8 million, we conclude that a third party buyer would value PSNH's rights and obligations under the Lempster Wind PPA at $5 million.

13. ASSET BUNDLING CONSIDERATIONS

This section explores whether the PSNH generating assets would bring more value if sold separately, as one bundled sale of all the generating assets, or as smaller groups of assets (e.g., fossil and hydro assets grouped separately).

The first step of this analysis is to determine the minimum bundles in which the assets might be feasibly packaged for sale. In our opinion, it is not practical to break up generation stations, or hydroelectric projects under the same FERC license, into individual units for sale. The greatest degree of granularity we considered in this valuation was whole stations and FERC-licensed projects.

There are other natural groupings among the generation assets. Newington and Schiller Station are unlikely to be sold separately due to the close proximity of their sites and the sharing of facilities, such as fuel oil storage tanks. Virtually all of Newington's fuel oil storage capacity is located at Schiller Station, with an above grade oil pipe to transport oil as needed to Newington. Both Newington and Merrimack Station rely on the dock facilities at Schiller Station to receive shipments of coal and oil from U.S. and international sources.

The hydro assets also enjoy some synergies as a fleet. Most of the units are quite small, so PSNH benefits from running the units as a fleet and sharing operation and maintenance across units. When hydro facilities control water flow, owning multiple units on the same river system can have benefits. Since the PSNH units are generally run of river, though, the benefits from owning multiple units on the same waterways are minimal. In our opinion, some typical buyers of hydro assets would not be interested in buying individual units. Bundling the hydro assets would likely expand the pool of willing buyers compared to individual sales.

Overall, we would not expect to see large premia or discounts resulting from bundling assets. Our Reference Scenario generally assumes continued operation under status quo conditions, which implicitly assumes the generation assets remain bundled in a single portfolio. We would expect a slight discount on the value if the assets had to be sold individually. The most important groupings are the hydro fleet and Newington/Schiller. Merrimack's added value resulting from synergies with Schiller is more ambiguous because it is unlikely a new owner would continue operating the station as a coal-fired plant. Merrimack Station's value as a potential redevelopment site is more independent from the other stations than its value in continuing operation.

The standalone combustion turbines have little to no value either on their own or as part of a fleet. Furthermore, a buyer would not be able to operate the units remotely from PSNH's Electric System Control Center in Manchester.

14. OPINION ON MARKET VALUE

14.1 Merrimack Station Reconciled Value

We conclude that the fair market value as of December 31, 2014 for the Merrimack Station is $10 million. In our view, this value is a reasonable estimate of the value that a Third Party Buyer would have offered at that date in a competitive auction of the asset, considering the judgments that such a buyer would make on risks involving market revenue, operating cost, environmental compliance cost and other uncertainties.

Our DCF analysis results lead us to conclude that a third party buyer would place no significant value on Merrimack Station as an existing coal-fired generation plant. Although some specific scenarios considered indicated a potential value as high as $159 million, the more likely outcome is that the plant would be a losing proposition for a buyer as currently operated. The DCF analysis indicates that the most likely outcome of continued operation of Merrimack Station is significant losses.

The comparable sales analysis indicated that even a coal plant slated for retirement holds some value, most likely for a site that is amenable to the development of a new generation resource due to existing transmission, fuel delivery and other infrastructure. The Brayton Point sale provides an upper bound on the value of Merrimack at $15 million.

Based on these two analyses, we estimate that the final reconciled value of Merrimack Station as of December 31, 2014 is $10 million, as shown in Table 26 below.

14.2 Schiller Station Reconciled Value

We conclude that the fair market value as of December 31, 2014 for Schiller Station is $5 million. In our view, this value is a reasonable estimate of the value that a Third Party Buyer would have offered at that date in a competitive auction of the asset, considering the judgments that such a buyer would make on risks involving market revenue, operating cost, environmental compliance cost and other uncertainties.

Our DCF analysis results lead us to conclude that a third party buyer would place no significant value on Schiller Station as an existing coal and biomass-fired generation plant. Of all the scenarios and sensitivities that were run, only one sensitivity indicated any positive value for Schiller in its current configuration. The DCF analysis indicates that the most likely outcome of continued operation of Schiller Station under a wide range of future market conditions is significant losses for the owner.

The comparable sales analysis indicated that even a coal plant slated for retirement holds some value, most likely for a site that is amenable to the development of a new generation resource due to existing transmission, fuel delivery and other infrastructure. The Brayton Point sale provides an upper bound on the value of Schiller at $5 million. Because of Schiller's small size, though, the dollars per kilowatt comparison to Brayton Point may fail to account for land and other site-related value. Also, the potential to realize some residual value from operating Schiller 5 effectively as a standalone unit immediately prior to retirement indicates a value at the upper end of the comparable sales range.

Based on these two analyses, we estimate that the final reconciled value of Merrimack Station as of December 31, 2014 is $5 million, as shown in Table 26 below.

14.3 Newington Station Reconciled Value

We conclude that the fair market value as of December 31, 2014 for Newington is $90 million. In our view, this value is a reasonable estimate of the value that a Third Party Buyer would have offered at that date in a competitive auction of the asset, considering the judgments that such a buyer would make on risks involving market revenue, operating cost, financing availability and other uncertainties.

Our DCF analysis results lead us to conclude that the fair market value as of December 31, 2014 for Newington is $90 million, considering a range of $79 to $103 million based on our assessment of uncertainties. In our view, a Third Party Buyer would put some weight on each of the cases in the range of values we have evaluated in the DCF analysis. The ongoing O&M costs for the facility and the market price for capacity are the most important uncertainties. We assume that the successful buyer would slightly discount the DCF-indicated value based on its heavy reliance on capacity revenue, which is subject to rapidly evolving ISO-NE markets. Based on this judgment and our judgments about other uncertainties inherent in a forecast of revenues and expenses over the next 15 years, we come to a DCF value of $90 million.

There are no transactions that we deem sufficiently comparable to Newington to provide additional insight into the fair market value.

Based on these two analyses, we estimate that the final reconciled value of Newington as of December 31, 2014 is $90 million, as shown in Table 26 below.

14.4 Hydro Units Reconciled Value

We conclude that the fair market value as of December 31, 2014 for PSNH’s hydro fleet is $120 million. In our view, this value is a reasonable estimate of the value that a Third Party Buyer would have offered at that date in a competitive auction of the asset, considering the judgments that such a buyer would make on risks involving market revenue, operating cost, financing availability and other uncertainties.

Our DCF analysis results lead us to conclude that the fair market value as of December 31, 2014 for PSNH’s hydro fleet is $120 million, considering a range of $76 million to $153 million based on our assessment of uncertainties. In our view, a Third Party Buyer would put some weight on each of the cases in the range of values we have evaluated in the DCF analysis. Ongoing O&M costs for the facility and natural gas prices (and by extension energy prices) are the most important uncertainties. We assume that the successful buyer would believe that O&M expenses could be brought closer into line with comparable hydro units in the Northeast, resulting in a DCF-indicated value that is higher than the Reference Scenario and all but the High Gas alternative scenario. Based on this judgment and our judgments about other uncertainties inherent in a forecast of revenues and expenses over the next 40 years, we come to a DCF value of $120 million.

The comparable transactions indicate a slightly higher value for the hydro units, without adjustment for declines in market outlook over the past 3-5 years. Comparable transactions since 2009 fall in the range of $0.35 to $0.45/kWh-year, which would indicate a value of $124 million to $159 million for PSNH's hydro fleet. However, a closer examination of the comparable transactions shows how they can be reconciled to our DCF-indicated value. The only comparable transaction to have closed since 2011 (when the long-term outlook for natural gas was significantly higher) had a unique deal structure in which 92% of the purchase price was in the form of assumed non-recourse debt. If we assumed the same 92% debt financing for the purchase of PSNH's hydro units under Reference Scenario assumptions, the DCF value would be $153 million. That value is equivalent to a sale price index of $0.43/kWh-year, exactly equal to the sale price index of the Brookfield transaction.

Based on these two analyses, we estimate that the final reconciled value of the PSNH hydro fleet as of December 31, 2014 is $120 million, as shown in Table 26 below.

14.5 Standalone Combustion Turbines Reconciled Value

We conclude that the fair market value as of December 31, 2014 for Lost Nation and White Lake combustion turbines is near zero. In our view, no Third Party Buyer would make a bid for either unit, considering the judgments that such a buyer would make on risks involving market revenue, operating cost, financing availability and other uncertainties, unless to acquire the site for other purposes.

Our DCF analysis results do not show any scenario in which the combustion turbines have positive value, including the High Gas scenario. Additional uncertainties related to whether the units could continue to operate in the capacity market if certain "pay for performance" standards currently under consideration are implemented further discount the possibility that any Third Party Buyer would count on earning a return from the purchase of the units at any price.

There are no transactions that we deem sufficiently comparable to these combustion turbines to provide additional insight into the fair market value. An appraisal of the land and real property at the sites was beyond the scope of this appraisal.

Based on these analyses, we estimate that the final reconciled value of White Lake and Lost Nation is near zero.

14.6 Burgess BioPower and Lempster Wind PPAs Reconciled Value

The following table summarizes the economic valuation of the two PPAs.

Table 25: Final Market Valuation of PPAs (Million 2014$)

	Million 2014$	
	Mark-to-Market Results Range	Final Valuation
Burgess BioPower PPA	($25) – ($189)	($125)
Lempster Wind PPA	($2.8) - $7.8	$5.0

14.7 Conclusion

The table below summarizes the final reconciled values for all PSNH owned assets as of December 31, 2014, with comparisons to their remaining net book value as of December 31, 2013.

The information on the costs, performance and condition of the PSNH generation facilities is based on information disclosed by PSNH in this proceeding. The statements of value contained in this report assume that there are no undisclosed liabilities associated with the generating assets or PSNH operations other than as expressly discussed herein. Any such additional liabilities could negatively impact the value of the assets.

Table 26: Summary of PSNH Generation Fleet Valuation

Plant/Unit	Net Plant Value (12/31/2013)	DCF-indicated Value Range[98]	DCF-indicated Value	Comparable Sales Range	Final Reconciled Value
		Million 2014$			
Fossil Plants					
Merrimack Station	$500	<$0 - $159	$0	$0 - $15	$10
Schiller Station	$78	<$0 - $36	$0	$0 - $5	$5
Newington	$36	$79 - $103	$90	None found	$90
Combustion Turbines					
Lost Nation	$0.4	<$0 - $0	$0	$0	$0
White Lake	$0.2	<$0 - $0	$0	$0	$0
Hydroelectric Units					
Ayers Island	$9.6	$9.5-$18.8	$14.5	$15.6 - $20.1	$14.5
Canaan	$2.7	$1.7 - $3.2	$2.5	$2.5 - $3.3	$2.5
Gorham	$1.0	$2.3 - $4.7	$3.5	$4.2 - $5.3	$3.5
Eastman Falls	$5.5	$3.2 - $7.8	$5.5	$8.9 - $11.5	$5.5
Smith	$6.3	$34.8 - $60.7	$47.0	$38.8 - $49.9	$47.0
Merrimack River Project (Amoskeag, Garvins and Hooksett)	$17.0	$26.6 - $60.7	$45.0	$50.1 - $64.4	$45.0
Jackman	$4.6	$0.9 - $3.2	$2.0	$3.4 - $4.4	$2.0
All Hydro	*$46.8*	*$76.0 - $152.9*	*$120.0*	*$123.5 - $158.8*	*$120.0*
Total PSNH Fleet[99]	*$660*		*$210*		*$225*

98 Cases in which the DCF does not solve indicate a negative value under a continuous operation scenario. We did not attempt to quantify negative values because in these scenarios the unit would likely be retired rather than operated at a loss for the 15-year book life.

99 Does not include PSNH ownership share in Wyman Station. Numbers may not add due to rounding.