John Antonuk

Areas of Specialization

Executive management; management audits and assessments; service quality and reliability management and measurement, utility planning and operations; litigation strategy; management of legal departments; human resources; risk management; regulatory relations; affiliate transactions and relations; subsidiary operations; and testimony development and witness preparation.

Relevant Experience

Electricity

Engagement Director for Liberty's prudence review of Arizona Public Services' acquisition of Four Corners Units 4 and 5 on behalf of the Arizona Commission. That review included an examination of short-and long-term planning issues including environmental risk, fuel economics, transmission system capability, and demand and usage growth. Liberty's review also evaluated the various rate and revenue requirement impacts resulting from the acquisition.

Engagement Director for Liberty's review of Entergy Texas's exit from Entergy's multi-state, multi-operating company approach to system planning and operation; and systems planning changes needed to support stand-alone operation by Entergy Texas for the PUCT.

Engagement Director for Liberty's integrated work with New Hampshire Commission Staff on an analysis of the competitiveness of the Public Service New Hampshire's generating fleet. This work provided a valuation of the power plants, addressing current and expected energy market conditions, the effects of increased cycling of units designed for baseload operations, potential costs associated with compliance with current and potentially increased environmental restrictions, impacts on the competitive market place, and other factors important for the Commission to consider in determining what future role might exist for utility-owned supply resources.

Engagement Director for Liberty's operational audit of utility staffing levels of each New York electric and gas utility for the New York Public Service Commission.

Project Director and lead consultant for Executive Management and Governance and Human Resources on Liberty's management and operations audit of Pepco for the District of Columbia Public Service Commission.

Engagement Director for Liberty's review of Pacific Gas & Electric use of risk assessment to drive electricity safety expenditures; included a review of the basis for identifying required programs, initiatives, and resources for the California Public Utilities Commission.

Project Manager for Liberty's second audit of Arizona Electric Power Cooperative for the Arizona State Corporation Commission which included reviews of fuel procurement and management, bulk electricity purchases and sales, power plant management, operations and maintenance, energy clause design and operation, and other issues affecting the prudence, reasonableness, and accuracy of costs that pass through the fuel and energy clause.

Project Manager for Liberty's second audit of Southwest Transmission Cooperative for the Arizona Commission, a companion examination of the transmission cooperative that is owned and operated in parallel with Arizona Electric Power Cooperative (a generation cooperative).

Project Director and lead consultant for Corporate Planning on Liberty's management and operations audit of Iberdrola SA/Iberdrola USA/NYSEG and RG&E for the New York Public Service Commission.

Project Director and lead consultant for Governance and Senior Management on Liberty's management and operations audit of Interstate Power and Light for the Iowa Utilities Board.

Project Director and lead consultant on Liberty's management and operations audit of the electricity, natural gas, and steam operations of ConEd for the New York Public Service Commission.

Project Director on Liberty's benchmarking analysis of Arizona Public Service for the Arizona Corporation Commission. This study covered a ten-year audit period and benchmarked Arizona Public Service's performance with the following metrics: Operational Performance, Cost Performance, Financial Performance, Affiliate Expenses, and Hedging & Risk Management.
Project Manager for Liberty's comprehensive, detailed affiliate relationships and transactions audit of Duke Energy Carolinas for the North Carolina Utilities Commission staff.

Project Manager for the performance of Liberty's audit for the Delaware Public Service Commission of a diagnostic audit of the affiliate costs borne by Delmarva Power, a member of the multi-state holding company, PHI. This review included an examination of the central services organization structure and operations, the procedures and methods used to allocate and assign costs, and test work to verify that execution of methods and procedures conforms to company procedures and to good utility practice.

Project Manager for Liberty's work for NorthWestern Energy to formulate long-range integrated infrastructure plans for its multi-state electric and natural gas distribution utilities. This project includes consideration of how to incorporate "Smart Grid" technology into infrastructure plans in a manner that will enable the Company to roll out new capabilities and services as technology makes them available, without undue acceleration of capital spending as uncertainties in this new marketplace become resolved.

Project Manager for Liberty's audit of Arizona Electric Power Cooperative for the Arizona State Corporation Commission which included reviews of fuel procurement and management, bulk electricity purchases and sales, power plant management, operations and maintenance, energy clause design and operation, and other issues affecting the prudence, reasonableness, and accuracy of costs that pass through the fuel and energy clause.

Project Manager for Liberty's audit of Southwest Transmission Cooperative for the Arizona Commission, a companion examination of the transmission cooperative that is owned and operated in parallel with Arizona Electric Power Cooperative (a generation cooperative). Among the issues examined in this audit were line losses.

Project Manager for Liberty's audit of Southwestern Public Service (SPS) for the New Mexico Public Regulation Commission that included a management review of the prudence of SPS' transactions under the Renewable Energy Credit tracker as conditionally approved by the Commission and a financial review of both revenues and expenses in order to provide an analysis of any under-recovery or over-recovery. Similarly, Liberty performed an evaluation of SPS' fuel clause process and regulations and a financial audit of fuel clause computation. In addition, reviews of purchases of coal, natural gas, oil, and purchased power, power plant operations, line losses, and cost allocation and assignment were also performed.

Project Manager for Liberty's audit of East Kentucky Power Cooperative, which included examinations of Governance, Planning, Finance, and Budgeting. Liberty performed for the Kentucky Public Service Commission an examination of governance at a generation and transmission cooperative serving 16 distribution cooperatives across the state. This study came in the wake of significant financial difficulties and also addressed planning, budgeting, financial, and risk functions and activities.

Project Manager for Liberty's audit for the Virginia State Corporation Staff of Potomac Edison Distribution System Transfer. Liberty examined the public interest questions associated with the transfer by an Allegheny Energy's utility operating subsidiary (Potomac Electric) of all of its electricity distribution operations business and facilities in Virginia to two rural electric cooperatives.

Project Manager for Liberty's audit of the fuel and purchased-power procurement practices and costs of Arizona Public Service Company for the Arizona Corporation Commission. Liberty completed audits relating to fuel procurement and management and on rate and regulatory accounting for related costs at Arizona Public Service Company for the Arizona Corporation Commission.

Project Manager for Liberty's audit of Duke Energy Carolinas for the North Carolina Utilities Commission. Scope included compliance with regulatory conditions and code of conduct imposed by the Commission after the merger with Cinergy, and affiliate transactions and cost allocation methods.

Project Manager for Liberty's audit of affiliate transactions of Nova Scotia Power on behalf of the Nova Scotia Utility and Review Board.

Project Manager for Liberty's audit for the New Jersey Board of Public Utilities of the competitive service offerings of the state's four major electric companies. Scope included corporate structure, governance, and separation, service company operations and charges, inter-affiliate cost allocations, arm's-length dealing with respect to a variety of code-of-conduct requirements, and protection of customer and competitor proprietary information.

Project Manager and witness for the staff of the Arizona Corporation Commission addressing the merits of the proposed acquisition of UniSource by a group of private investors.

Project Manager and witness before the Oregon Public Utility Commission addressing the merits of the proposed acquisition of Portland General Electric by a group of private investors.

Engagement Director for Liberty's provision of engineering and technical assistance to the Vermont Public Service Board in connection with review of public necessity and convenience related to the Northwest Reliability Project, which would add a major new 345kV transmission plan to provide an additional source of electricity to serve Vermont's major load growth in its northwest region. The project involved transmission reinforcements at lower voltages and significant substation upgrade work. The proceedings had numerous public, private, and government interveners, who raised issues regarding project need, available electrical alternatives, routing and design, and electromagnetic radiation.

Project Manager for Liberty's support for the New Hampshire Public Utilities Commission in its charge to oversee the divestiture of the Seabrook nuclear plant as part of a major restructuring settlement. The sale produced record high compensation for nuclear facilities in the country.

Project Manager and witness for Liberty's assessment of fuel procurement, affiliate transactions, and automatic adjustment clause implementation for the staff of the Nova Scotia Utility and Review Board in rate case of Nova Scotia Power.

Project Manager for Liberty's engagement on behalf of Boston Edison to examine the company's affiliate relations, including issues of the valuation of assets transferred to an affiliate. Testified in proceedings before the Massachusetts Department of Telecommunications and Energy (formerly the Department of Public Utilities) on several telecommunications issues, including: (a) development of competition, and legislative and regulatory-policy changes supporting it, (b) electric-utility entry into telecommunications markets, (c) costs, prices, and market value of network elements, (d) requirements of the Telecommunications Act of 1996, (e) assessment of compliance with commission orders, company procedures, and service agreements regarding limits on affiliate interactions, (f) inter-company loans, guarantees, and credit support among utilities and their affiliates, (g) accounting for affiliate transactions, (h) obligations to allow nondiscriminatory access to network infrastructure to third parties, and (i) cost pools, overhead factors, and allocation of common costs among utility and non-utility affiliate activities and entities.

Project Manager for Liberty's major consulting engagement for the New Hampshire Public Utilities Commission. Liberty examined management, operations, and costs at Public Service Company of New Hampshire/Northeast Utilities, which is engaged in the operational and cost-accounting separation of its network into segments, for the purposes of restructuring service offerings to allow competition in certain aspects of electric-energy supply. This engagement included an assessment of valuations of nuclear and fossil units, as well as supply contracts with independent-power producers. Liberty also assisted in efforts to settle rate case and restructuring disputes involving, among other issues, stranded costs associated with power plants. The scope of Liberty's work included the development of plans and protocols for power plant (fossil, hydro, and nuclear) and power supply contract assets, as well as the oversight of activities associated with asset auctions.

Engagement Director for Liberty's evaluation of corporate relations and affiliate arrangements of Dominion Resources, Inc. and Virginia Power for the Virginia State Corporation Commission. This project addressed all significant aspects of corporate governance, operating relationships, and affiliate arrangements between the two entities.

Project Director for Liberty's evaluation of a report prepared by a consultant to the Hawaii Public Utilities Commission on the relationship between Hawaiian Electric Industries (HEI), a diversified utility-holding company, and Hawaiian Electric Company (HECO), its principal subsidiary and operating electric utility.

Project Director for all aspects of Liberty's comprehensive management and operations audit of West Penn Power Company for the Pennsylvania Public Utilities Commission. Managed focused reviews of the Company's affiliated costs, power dispatch and bulk power transactions, customer services, finance, and corporate services. Presented testimony before the PA PUC on behalf of the Office of Trial Staff regarding the results of the audit in West Penn's rate case.

Lead Consultant for affiliate relations for Liberty's assignment of providing assistance to Delmarva Power & Light Company in developing and implementing self-assessment and continuous-improvement processes.

Project Director for Liberty's reviews of fossil-fuel procurement and administration in Liberty's management/performance audits of the Centerior Energy Company's operating companies - Cleveland Electric Illuminating Company and Toledo Edison Company - and Ohio Edison, Monongahela Power (an Allegheny Power System operating company), and Cincinnati Gas & Electric, for the Public Utilities Commission of Ohio.

Served as advisor to the administrative law judge of the Delaware PSC responsible for hearing cases regarding the implementation of the new law that restructures the electric-utility industry in Delaware.

Engagement Director for nuclear plant performance-improvement projects that Liberty conducted for Duquesne Light Company, Centerior Energy, Nebraska Public Power District, and Pennsylvania Power & Light Company (PP&L).

Engagement Director for a Liberty assignment for Florida Power Corporation, regarding a proposal by the Tampa Electric Company to construct transmission lines to serve the cities of Wauchula and Fort Meade, Florida. Liberty's testimony helped convince the Florida Public Service Commission that Tampa Electric Company's proposed line was uneconomic.

Directed Liberty's engagement to assist a regional electric generation and transmission cooperative, whose members' combined operations make it a major competitor in the state's electricity business, to conduct its first-ever comprehensive and formal strategic-planning process.

Natural Gas

Executive Sponsor of Liberty's investigation of Peoples Gas of Chicago's Accelerated Main Replacement Program for the Illinois Commerce Commission. This project includes detailed reviews of both the overall program design and management of the main replacement program, as well as the execution of replacement work by company and contractor crews.

Project Manager for Liberty's review of Connecticut's program to produce a major expansion of natural gas availability and use by all three of its natural gas utilities for the PURA.

Project Manager for Liberty's examination of safety programs and activities of NiSource's Maine subsidiary Northern Utilities for the Maine Public Service Commission.

Project Manager for Liberty's focused and general management audits of NJR, New Jersey Natural Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues. Personally performed the reviews of governance, EDECA requirements compliance, and legal services.

Project Manager on a major focused audit of Peoples Gas/Integrys that Liberty performed for the Illinois Commerce Commission. Audit topics included natural gas forecasting, portfolio design and implementation, gas purchase and sale transactions, controls, organization and staffing, asset management, off-system sales, storage optimization, and all other issues related to gas supply over a period of eight years.

Project Manager and witness on three recent audits of fuel (primarily coal and natural gas) procurement and management practices of Nova Scotia Power, a review of the merits and mechanics of a company-proposed automatic recovery method for energy costs, and an audit of affiliate relationships (including coal, electric power, and natural gas procurement activities) performed for the Nova Scotia Utility and Review Board.

Project Manager for Liberty's focused and general management audits of SJI, South Jersey Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues. Personally performed the reviews of governance, EDECA requirements compliance, and legal services.

Project Manager for Liberty's work with staff of the Virginia State Corporation Commission to evaluate the services of an affiliate providing gas portfolio management services under an asset management agreement with Virginia Natural Gas, an operating utility subsidiary of Atlanta-based AGLR.

Project Manager for Liberty's focused audit of NUI Corporation and NUI Utilities. This audit included a detailed examination of the reasons for poor financial performance of non-utility operations, downgrades of utility credit beneath investment grade, and retail and wholesale gas supply and trading operations. Also examined performance of telecommunications, engineering services, customer-information-system, environmental, and international affiliates. The audit included detailed examinations of financial results, sources and uses of funds, accounting systems and controls, credit intertwining, cash commingling, and affiliate transactions, among others. Liberty's examination included very detailed, transaction-level analyses of commodities trading undertaken by a utility affiliate both for its own account and for that of utility operations.

Project Manager for Liberty's comprehensive management audit of United Cities Gas Company for the Tennessee Public Service Commission. Responsible for the focused reviews of affiliate interests, executive management and corporate planning, and vehicle management.

Lead Consultant in Liberty's management audit of Connecticut Natural Gas Company for the Connecticut Department of Public Utility Control (DPUC). Responsible for reviews of organization and executive management and legal management.

Lead Consultant in Liberty's management audit of Southern Connecticut Gas Company for the DPUC. Responsible for organization and executive management, affiliates, and legal management. Included valuation of a major, rate-based LNG facility being offered for sale.

Directed Liberty's management audit of Yankee Gas Services Company for the DPUC.

Engagement Director for Liberty's evaluation of regulatory needs and alternatives for the Georgia Public Service Commission in regulating the state's local-gas-distribution companies in the aftermath of FERC Order 636.

Project Director for Liberty's review of gas-purchasing policies and practices at Pike Natural Gas Company and Eastern Natural Gas Company for the Public Utilities Commission of Ohio. Responsible for the review of organization and staffing and regulatory-management issues.

Combination Utilities

Engagement Director for Liberty's examination of the cost-allocation methods of Baltimore Gas & Electric Company and its affiliates for the Maryland Office of People's Counsel.

Project Director for Liberty's focused management audit of affiliate transactions of Public Service Electric & Gas Company (PSE&G) and the unregulated subsidiaries of Public Service Enterprise Group, Inc., the parent, for the New Jersey Board of Regulatory Commissioners. Task leader for the review of organization and planning, and executive management.

Project Director for Liberty's management and operations audit of New York State Electric & Gas Corporation for the New York Public Service Commission (NYPSC). Responsible for managing the review of corporate planning and organization, service centralization, specific corporate services, and finance and accounting.

Project Director for Liberty's management and operations audit of Central Hudson Gas & Electric Corporation for the NYPSC.

Telecommunications

Arbitrator named by the District of Columbia Public Service Commission to address industry-wide need for amendments to interconnection agreements as a result of the FCC's Triennial Review Order.

Project Manager for assistance being provided to the Administrative Law Judge of the Delaware Public Service Commission hearing the arbitration to address industry-wide need for amendments to interconnection agreements as a result of the FCC's Triennial Review Order.

Project Manager for Liberty's engagement to serve as advisors to commissioners of the District of Columbia Public Service Commission in their review of the Section 271 application of Verizon to provide in-region, interLATA service in the District.

Project Manager for Liberty's engagement to serve as advisor to the administrative law judge of the Delaware Public Service Commission in the review of the Section 271 application of Verizon to provide in-region, interLATA service in the state.

Retained by the Idaho Public Utilities Commission to serve as administrative law judge in complaint proceedings involving three paging companies and Qwest, involving a variety of financial disputes arising out of interconnection and tariff purchases.

Conducted wholesale performance metrics training for staff members and commissioners of the Pennsylvania Public Utility Commission as part of efforts to monitor service quality and payments under the Verizon Performance Assurance Plan adopted in connection with the RBOC's entry into the in-region inter-LATA market in Pennsylvania.

Engagement Director for Liberty's comprehensive financial review of Verizon New Jersey Inc. (VNJ) for the New Jersey Board of Public Utilities. The review had three parts: a financial evaluation; a review of merger costs and savings; and an assessment of affiliate costs and transactions.

Engagement Director for Liberty's audit of Ameritech-Ohio policies, procedures and compliance with service quality performance requirements under Ohio's Minimum Telephone Service Standards.

Engagement Director for Liberty's audit of Qwest's performance measures for the Regional Oversight Committee (ROC). Responsible for the evaluation of the processes and data tracking of several hundred wholesale and retail performance indicators including service areas such as provisioning, OSS access, maintenance and repair, and billing.

Project Manager and hearing administrator for Qwest's 271 hearings for the commissions of Idaho, Iowa, Montana, New Mexico, North Dakota, Utah, and Wyoming.

Engagement Director for Liberty's assistance provided to the Staffs of the Virginia State Corporation Commission and the New Jersey Board of Public Utilities in the implementation of the 1996 Telecommunications Act.

Project Manager for Liberty's assistance to Delaware PSC arbitrators in seven different interconnection cases arising out of the Telecommunications Act.

Served on an arbitration board in Mississippi, and as the sole arbitrator in two cases in Idaho regarding interconnection agreements between incumbent local-exchange companies and new entrants to the local telephone market.

Engagement Director for Liberty's work determining permanent prices for the unbundled-network elements of Southwestern Bell Telephone for the Oklahoma Corporation Commission.

Engagement Director for Liberty's provision of arbitration services to the North Dakota Public Service Commission and Nebraska Public Service Commission in cases involving implementation of the Telecommunications Act of 1996.

Engagement Director for Liberty's combined comprehensive management/affiliate-relations audit of Bell Atlantic - Pennsylvania for the PA PUC, and affiliate relations audit of Bell Atlantic - District of Columbia for the Public Service Commission (DCPSC) of the District of Columbia. Served as team leader with responsibility for the coordination of the review of executive management, finance, and support services.

Engagement Director for Liberty's examination of the accounting and allocation on lobbying costs of Bell Atlantic for an eight-year period for the DCPSC. Engagement included an examination of the propriety of policies and procedures for assigning and allocating lobbying costs.

Engagement Director for a management audit of GTE South, Inc. for the Kentucky Public Service Commission. This examination included a review of GTE's affiliate transactions.

Project Director for Liberty's evaluation of New York Telephone's transactions with affiliates for the NYPSC. Responsible for the review of affiliates involved in directories publishing, government affairs, international activities, information services, and the legal-affairs entity.

Project Director for Liberty's management audit of the affiliated interests of C&P Telephone of Maryland performed on behalf of the Maryland Public Service Commission.

Engagement Director for Liberty's two assignments for the DCPSC in reviewing Bell Atlantic - District of Columbia's construction-program planning and quality-of-service standards.

Other Companies

Set up and managed service and facilities section of the PP&L Regulatory Affairs Department. Counseled utility management on regulatory and legislative matters. Litigated rate related and facility construction proceedings before agencies and the courts.

Attorney for the PA PUC. Assigned as counsel to the Commission's Audit Bureau in developing a comprehensive management-audit system. Negotiated contracts for the first commission-ordered management audits in Pennsylvania. Revised Commission organization and practice to conform to regulatory-reform legislation.

Testimony

Nova Scotia Utility and Review Board – Testimony on the prudence of fuel procurement, affiliate relationships associated with fuel management, and use of an automatic adjustment clause to recover fuel costs.

Arizona Corporation Commission – Testimony on the merits and conditions of the proposed acquisition of UniSource by private investors.

Oregon Public Utility Commission – Testimony on the merits and conditions of the proposed acquisition of Portland General Electric by private investors.

Virginia State Corporation Commission - Testimony in arbitration cases regarding interconnection agreements between Bell Atlantic - VA and competing local exchange companies.

PA PUC - Presentation of management-audit recommendations and benefits for selected conclusions in West Penn Power Company request for rate increase.

Maryland Public Service Commission - Presentation and defense of management-audit conclusions, recommendations, and cost implications in C&P Telephone Company of Maryland (Bell Atlantic) rate case.

Illinois Commerce Commission - Testimony about fuels organization, procurement, and management in fuel-cost reconciliation proceedings.

Maryland Public Service Commission - Testified regarding Baltimore Gas & Electric Company's affiliate relations.

Tennessee Regulatory Authority - Testified regarding Liberty's recommendations in a management audit of United Cities Gas Company.

Education

J.D., with academic honors, Dickinson School of Law
B.A., cum laude, Dickinson College

Jim Letzelter

Areas of Specialization

Utility planning and operations; production cost modeling; financial analysis; energy market assessment; transmission system and ISO analysis; power market strategy; asset valuation; management audits and assessments; litigation support; risk analysis and risk management.

Relevant Experience

The Liberty Consulting Group

Led Liberty's prudence review of Arizona Public Services' acquisition of Four Corners Units 4 and 5 on behalf of the Arizona Corporate Commission. That review included an examination of asset value and short-and long-term planning issues including environmental risk, fuel economics, transmission system capability, and demand and usage growth.

Lead Consultant for Liberty's integrated work with New Hampshire Commission Staff on an analysis of the competitiveness of the Public Service New Hampshire's generating fleet. This work provided a valuation of the power plants, addressing current and expected energy market conditions, the effects of increased cycling of units designed for baseload operations, potential costs associated with compliance with current and potentially increased environmental restrictions, impacts on the competitive market place, and other factors important for the Commission to consider in determining what future role might exist for utility-owned supply resources.

Lead Consultant on Liberty's review for the Public Utility Commission of Texas concerning Entergy Texas' exit for the Entergy System Agreement.

Lead Consultant for Liberty's fuel and purchased power audit of Entergy Mississippi providing comprehensive audit services of Entergy's production cost models and processes for the Mississippi Public Service Commission. Assessed all of the models and processes associated with the Entergy's Monthly Energy Plan, the Weekly Procurement Process, and the Next- and Current-Day processes.

Lead Consultant for Liberty's work as Technical Consultant for the Delaware Public Service Commission in 2013, 2014 and 2015 SOS auctions. Provided pre-bid monitoring included monitoring of announcements, bidder communication, bidder certification, bid system training, and bid system performance and market assessment. Bid day monitoring included live monitoring of the auction on-site, verification of bids, notification of winners, and contract signing.

Lead Consultant on Liberty's management and operations audit of Pepco for the District of Columbia Public Service Commission. Led Liberty's review of Power Supply.

Generation & Transmission Operations

Provided a renewable power developer with consulting support on placement of assets with respect to transmission topography. Study used to select connection points and predict bus-level power prices.

Performed an assessment of transmission constraints for a merchant generator for use in an asset valuation study. Used transmission constraint information to predict long-term power price implications, and the ability to move power to alternative markets.

Developed a power market price model based on dispatch costs, including transmission constraints and costs for a merchant power generation company.

Risk Analysis & Asset Portfolio Assessment

For a renewable energy development company, developed a sophisticated financial risk analysis model used by the client to bid on power project RFPs and to acquire capital from equity investors. Provided ongoing risk modeling and overall financial and market intelligence support.

For a power trading organization, developed a custom market intelligence tool to extract data from an industry standard forecasting package to meet the specific needs of energy traders.

Performed efficient frontier analyses incorporating probabilistic market forecasts for a wholesale generator. Potential generator additions were analyzed including expected means, standard deviations and the corresponding correlations of key inputs such as fuel price and demand. These forecasts were then utilized to determine the expected revenues and variance of the revenues to determine both existing system risk profile and the resulting risk profile for each addition.

For a merchant generating company, developed and deployed asset valuation tools utilizing correlated probabilistic market information. This provides a measure of intrinsic and extrinsic value to potential acquisition/development projects.

For a public power authority, performed a comprehensive risk analysis on the issue of nuclear plant life extension (NUPLEX) for the client's asset. Developed a risk management simulation tool to manage data and produce projections of future plant profitability under varying market, cost and regulatory scenarios. The work product was successfully employed by the client to make an informed decision on a major investment.

For a merchant generating company, developed and implemented a risk analysis and risk management tool for dealing with the uncertainty of emissions regulations. Implemented the model for the client and successfully led the organization through the maze of issues, including capital allocations, plant operations and investments that they faced.

Power Price Forecasting & Market Assessment

For an investment bank syndicate, provided critical power market assessments for use in a major energy bankruptcy case. On behalf of the official creditor's committee, provided power price forecasts, power market assessments, fuel market reviews and power plant financial assessments. Work product was successfully used in litigation.

For a merchant generating company, led the power market price forecasting initiatives related to power plant acquisition and development. Guided the analytical team in development of scenarios, model and data validation, and overall quality of results to be used for major investment and financing decisions in the U.S.

For a turbine manufacturer, performed power market assessments for a major turbine manufacturer. Developed forecasts of energy, capacity, and ancillary service prices to be used to define the place in the market for an emerging turbine technology.

For a European investment bank consortium, provided a detailed, comprehensive market assessment of global power markets to review the market for power generation turbines. With substantial investment in turbine manufacturers, the consortium relied on the expertise to make changes to their investment portfolios and shore up risk-plagued securities.

For a merchant generating company, provided market price forecasts to be utilized in the development and acquisition of power plants. Included forecasts of energy, capacity and ancillary services prices.

Asset Valuation, Acquisition & Development Support

For a merchant generating company, provided comprehensive power plant acquisition support. Managed market assessment process, provided asset valuations, defined acquisition price and assisted in property tax negotiations. Also highlighted the value of the asset with respect to asset re-powering opportunities.

For a merchant generating company, led the analytical efforts behind the acquisition of portions of three nuclear power plants. Included market comparables assessment, decommissioning fund valuation, and materials and supplies inventory valuation.

For a merchant generating company, provided a comprehensive financial and market analysis of re-powering opportunities for the client's older asset base. Included detailed assessment of market conditions and expected returns for various re-powering opportunities.

For a merchant generating company, successfully developed and deployed software to determine generating asset intrinsic and extrinsic value. Program utilizes probabilistic market price output from Aurora. Program also develops equilibrium market pricing for long-term time frame.

For a G&T co-op, provided a thorough asset valuation study to assess the impact of market uncertainties and financing parameters on the organization's asset values. Successfully provided the client with recommendations for potential divestiture and regulatory initiatives.

For a merchant generating company, provided a massive market assessment in support of a corporate power plant acquisition initiative. Included development of a detailed financial and valuation model for the client to use in future asset acquisition studies.

For a turbine manufacturer, provided a power market assessment and financial analysis to assess the viability of a new class of combined cycle units for the U.S. power markets. Included a comprehensive scenario analysis of fuel prices, load growth, emissions regulations and transmission constraints.

Model Implementation, Validation & Development

For an energy trading company, developed a custom interface for the AURORA electric power market model to seamlessly integrate within the client's analytical framework. Included data development and model validation, and custom report development.

For a merchant generating company, managed the overall process for transitioning the resource planning and forecasting department to AURORA. Included full data development, training, interface development, testing and validation. Successfully converted the business process to an AURORA-based system.

For an energy data provider, performed full audit review and validation of the client's power price forecasting processes. Reviewed input and output parameters for all national power price forecasts to improve the organizations accuracy and credibility.

For a merchant generating company, developed a customized power price forecasting tool to provide acquisition and development support, restructuring support and general corporate financial forecasts. Developed data sets for the model and provided training and validation.

For a regulated utility, developed a customized power price forecasting tool to provide acquisition and development support, restructuring support and general corporate financial forecasts. Developed data sets for the model and provided training and validation.

Emissions Analysis

For a merchant generating company, developed an enterprise-wide strategy for managing emissions constraints for the generating asset portfolio. Developed a probabilistic assessment model to consider plant operations, emission rates, control technology options, market forces and potential and existing emissions constraints. Deliverables resulted in a cohesive strategy and lobbying campaign for favorable regulations.

For a merchant generating company, performed a risk analysis of greenhouse gas regulation impacts on a potential fossil-fired asset portfolio acquisition. Deliverables included a detailed assessment of financial and asset value implications of various regulatory scenarios.

For a merchant generating company, provided an assessment of emissions regulations impacts on potential asset acquisitions. Included a market assessment of abatement technology costs and operating parameters, and a review of potential emissions regulations scenarios.

For an industrial chemical company, assessed the market for consumable chemicals to be used by emission control technologies. Client had an opportunity to take a position in supplying chemicals and needed an understanding of the regulatory and market conditions to support the investment.

Regulatory & Litigation Support

For a regulated electric & gas utility, provided regulatory and market analysis support in a contentious issue between competing utilities related to marketing and promotional practices. Assessed potential damages and rate impacts of regulatory decisions on the issue.

For a regulated electric & gas utility, performed a gas cost of service study to be use in a major rate case. Developed a proprietary model for cost allocation and financial implications.

For a regulated electric & gas utility, performed a massive cost of service study for a wholesale rate case brought before FERC. Implemented FERC's ECOS software and performed full study for a consortium of legal experts and consultants engaged in the case. The study led to a favorable resolution of issues.

For a regulated electric & gas utility, developed a custom ROE Calculation model to be used in rate-setting. The model captured highly complex algorithms into a manageable user interface. The model was approved by the state utility regulator and was successfully implemented.

For a regulated electric & gas utility, provided litigation support in a major utility restructuring proceeding. The project including development of exhibits, preparation of witnesses, developing testimony and cross-examination, and performing power market analyses.

Emerging Energy Technology Support

For a renewable energy development company, provided overall corporate development and supported the acquisition of investment capital.

For an emissions control technology company, provided comprehensive support for commercialization of a newly patented NOx control technology. The project included a detailed market assessment, development of a financial analysis tool for customer proposals, acquisition of venture capital and strategic planning for the company. All aspects of the project were highly successful.

For an energy technology company, provided market assessment and strategic support for an emerging energy conservation technology company. The company used advice to seek capital and market the products.

Publications & Presentations

"U.S. Power Markets Overview: An Issues Overview and Enhanced View of Eastern Markets," May 6, 2008, Gerson Lehman Group speaker sponsorship

"Economics of Coal-Fired Generation," March 2007, Goldman Sachs private speaker sponsorship

"Power Risk Management: Environmental Economics," 2007, Goldman Sachs private speaker sponsorship

"Predicting Long-Term Energy Prices with OptQuest: The GenMetric Model," May 3, 2006, Crystal Ball User Conference

"Using the Efficient Frontier," January 18, 2006, Internationally-broadcast Web Conference sponsored by Decisioneering

"Building the Perfect Generation Portfolio," September 2005, Public Utilities Fortnightly

"Finding the Efficient Frontier: Power Plant Portfolio Assessment," June 13, 2005, Crystal Ball User Conference

"The Efficient Frontier and Power Plant Portfolio Analysis," September 2004, EPIS Electric Market Forecasting Conference

"Power Asset Transactions: Regulatory Risks," June 24, 2004, Infocast Buying Selling & Investing in Energy Assets 2004

"Power Generation Asset Valuation," June 17, 2004, Crystal Ball User Conference

"Assessing Risk in a Changing Market," March 29, 2004, Platts Global Power Markets

"Our Energy Future," January 14, 2004, NET 2004 Conference

"Our Transmission Future," January 14, 2004, NET 2004 Conference

"Models Matter: The Art of LMP," November 6, 2003, Platts Electric Market Design Conference

"Risk Management Panel Discussion" Moderator, September 2002, EPIS Electric Market Forecasting Conference, Skamania, WA

"Venture Capital" Panel Moderator, December 3, 2001, Strategic Research Institute Energy Investor's Summit

"Leveraging AURORA: Modeling New Resource Development," November 13, 2001, EPIS Electric Market Forecasting Conference

"Optimizing Emissions Compliance: Emerging Technologies & Multi-Pollutant Regulation," July 26, 2001, Coal-GEN 2001

Letzelter, James C., Public Utilities Fortnightly, "The New Venture Capitalists: Utilities Go Shopping For Deals," December 2000

"Power Plant Emissions: Modeling Market Implications," September 22, 2000, EPIS Electric Market Forecasting Conference

"Emissions Modeling for Optimum Compliance," July 1999, Infocast SIP Call Conference

Letzelter, James C., Public Utilities Fortnightly, "Surviving the SIP Call: Fossil Plant Economics Under NOx Control," May 1, 1999

"Managing Emission Limit Changes: Challenges & Opportunities," January 29, 1999, CBI Merchant Plant Conference

Letzelter, James C., Power Finance & Risk, "The Impact of NOx Limits on U.S. Energy Markets," January 11, 1999

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Testimony

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IR 13-020

Public Service Company of New Hampshire

Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market

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and

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June 7, 2013

Contents

Executive Summary

Bringing the state's electricity rates down to regional levels comprised a major goal of restructuring in the late 1990s. The legislature, the New Hampshire Public Utilities Commission (Commission), and the overwhelming number of stakeholders involved in restructuring saw the fossil and hydro resources of Public Service Company of New Hampshire's (PSNH) as a major asset in achieving that goal. A little over a decade later, those resources, taken as a whole, have gone from saving customers money to costing them significantly, relative to available market alternatives. One measure of the gap that now exists is to measure the difference between PSNH's default service rate, 9.5 cents per kilowatt-hour (kWh), and prevailing retail market prices, 7.0 – 8.0 cents per kWh, which are lower than PSNH's rate by approximately 15 to 25 percent.

In light of the current situation, on January 18, 2013, the Commission opened an investigation, to be performed by Commission Staff (Staff), to review market conditions affecting the default service rates of PSNH in the near term and how PSNH proposes to maintain safe and reliable service to its default service customers at just and reasonable rates. In addition, the investigation was to explore the impact on the competitive electric market in New Hampshire of PSNH's continued ownership and operation of generation facilities. To assist in its investigation, Staff retained the services of The Liberty Consulting Group, a consulting firm with experience with electric industry restructuring in New Hampshire, particularly in PSNH's service territory and with current experience in Northeast natural gas and energy markets. The investigation over the last few months involved obtaining information from PSNH and meetings with various stakeholder groups to elicit various viewpoints on the status of PSNH's default service rate and generation ownership both today and looking forward.[1]

In summary, the situation looks to worsen, as continuing migration from PSNH's default service by customers causes an upward rate trend. We find no supportable basis for optimism that future market conditions will reverse this unsustainable trend, especially in the near term. To the contrary, the PSNH fossil units face uncertainties that combine to create a risk of further, potentially substantial increases in costs.

At first glance, one option is to allow the current situation to continue, on the premise that the sizeable gap between default service and market prices would induce increasing levels of migration, and with the premise that default service is simply meant to be a safety net. If this were true, it would save customers money and help competitive suppliers build a long-term foundation for competitive choice. We found competitive retail suppliers, however, far less interested in the "headroom" created by the significant gap between market and PSNH's default prices, as compared with supporting a market that is conducive to competition over the longer term. Their interests focus more on a market that operates under a stable policy framework and rules. Their concerns about PSNH focus less on current default service prices and more on the

[1] Staff would like to take this opportunity to thank PSNH and all of the stakeholder groups for their cooperation and assistance throughout this investigation.

institutional barriers created by the presence of the distribution company in the energy portion of the business.

Wholesale suppliers, whose interests are overlapping, but not identical to those of retail suppliers, also focus on competitiveness issues (such as what incentives full cost recovery creates for PSNH in bidding its units into the market through ISO New England). We found consensus between them that the best approach from a market perspective would be to remove PSNH from the energy supply business, with PSNH remaining as a provider of electric distribution and transmission services, and establish a prompt and effective transition path that would permit third-party wholesale and retail providers to bring market-based rates to all of New Hampshire's residents and businesses.

Those we consulted who speak for customers (both large and small) share this view. None expressed the view that continuing default service rates at a substantial above-market price represented an appropriate option. The environmental groups with whom we met did not favor this option either. Some states have promoted a gap between their equivalents to default service and market prices to induce switching. None that we know of, however, support such a sizeable gap or the prospect of its steadily increasing economic burden on those end users who have not chosen to move from PSNH as their energy supplier.

Taking no action threatens to leave a dwindling yet still substantial number of the state's residents and small businesses facing ever higher costs for service relative to market alternatives and could eventually threaten the financial health of PSNH. Setting PSNH's default service rates closer to market rates and opening a proceeding to address recovery of deferred costs could provide short-term relief. Nonetheless, simple deferral of recovery is ultimately likely to do no more than postpone the burden that over-market costs represent. PSNH does not appear to have the ability to significantly reduce those costs without potential financial consequences to the company. Cost reductions could be attained through existing Commission authority; however, legislative action may also be required.

Securitization[2] represents one possible measure. It has the potential for producing a large reduction in the capital cost component of default service rates. Our analysis, using current market conditions[3], demonstrates that, under a wide range of assumptions, a post-divestiture combination of (a) market-procured power plus (b) costs for amortizing uneconomic ("stranded"[4]) costs may very well produce total costs less than what default service customers now pay. Considering the very strong likelihood that the gap between market and PSNH default service prices will increase over time, an option that would not only prevent growth in that gap, but actually reduce it, may prove a very powerful tool, albeit one that invites consideration of not just regulatory, but also statutory change. Spreading responsibility for stranded costs beyond default service customers would represent another such measure. Both approaches raise policy,

[2] Securitization is a process by which a utility creates a special purpose entity to issue bonds for the purpose of recovering stranded costs.
[3] Current market conditions involves current costs and forecasts but does not include environmental contingencies.
[4] Stranded costs can generally be defined as the difference between costs expected to be recovered under regulated rates and those recoverable in a competitive environment.

legislative, and potential litigation issues that call for engagement with stakeholders and the legislature in what we would anticipate to be complex and controversial processes.

There is not a great deal of time for the State to act to address what will become an increasingly onerous burden for what now comprises a majority of the state's residents and many of its smaller businesses. If it were determined that PSNH should exit the energy supply business, some of the options for facilitating that exit would take substantial effort.

Divestiture is one of those options. It can take the form of a public, competitive sale or a transfer of generation assets to a PSNH affiliate at a determined price, such as net book value. Either option would require a means for addressing the difference between the sale or transfer price and book value. PSNH has very recently observed that natural gas prices may soon reach levels that would make the PSNH fossil units market competitive. If PSNH is correct, then one would expect the fossil/hydro fleet as a whole to generate more than book value, particularly given that recent sale prices and preliminary indications from market participants show that the hydro units have value substantially in excess of their book cost.

We, however, do not share the view of PSNH, nor has the company in response to our requests provided any analysis confirming its view of fossil fleet value. Our analysis shows that the fossil units have very little market value. The detailed analyses that potential buyers would perform were outside the scope of our assignment, but the preliminary work we did strongly supports the following observations:

- The fossil units have minimal economic value, far below the net book costs.
- The hydro units have economic value far in excess of their net book costs.
- Taken together, however, the fossil/hydro fleet has value substantially less than net book costs.

PSNH has also made the case that the fossil units, apart from whether they have net positive value, provide an important form of fuel diversity insurance. The company cites recent instances of natural gas price spikes in the New England region. Such price spikes (resulting from constraints in the regional pipeline system) present a serious challenge to the region's reliability and are unlikely to be resolved through additional pipeline expansion in the near-term. Nonetheless, even at the level that constraints have occurred recently, their frequency and severity have not served to give the PSNH fossil units enough of a boost to overcome their negative value. Further evidence that this insurance role is not viewed as viable comes from recent sales at low prices of New England fossil assets that operate similarly to those of PSNH. In addition, we find notable the failure of ISO-NE to assign value to coal as a source of fuel diversity, even though the issue of fuel diversity is a region-wide one. In fact, the ISO-NE's current interest in implementing a "pay-for-performance" program, if approved, will likely do little to enhance the "insurance value" of PSNH's fossil units.

Another reason undercutting the PSNH view of insurance value is that potential environmental rules create the possibility of substantial new capital investment and operating restrictions to be applied to the fossil units. The risk of cost increases from future environmental mandates is an additional and significant concern. This certainly was the view of the environmental groups with which we met. Their goals include the shutdown of the fossil units for environmental reasons, but the information they provided us was strongly rooted in cost considerations.

The fundamental difference in view of fossil fleet value between PSNH, on the one hand, and the overwhelming weight of stakeholder opinion, on the other hand, suggests an interesting alternative: a transfer of the fossil/hydro fleet to an affiliate at net book cost would enable PSNH's parent to gain value if its views of value are strongly held. Such a transfer would eliminate stranded costs as an issue, which is important, given the prevailing view that the fleet does not have positive economic value. The transfer would also eliminate contention over stranded cost sharing.

Many important questions remain to be answered. We believe that they require prompt answers, given the circumstances. The Commission should consider opening a proceeding to receive comments and recommendations from PSNH and other stakeholders regarding this report and the issues it addresses. Particular focuses should include the following:

- Whether PSNH's default service rate remains sustainable on a going forward basis
- What "just and reasonable" means and what it requires with respect to default service in the context of competitive retail markets
- Analytically supported views of the current and expected value of PSNH's generating units under an appropriately designed range of future circumstances.
- What means exist to mitigate and address stranded cost recovery

The valuations of PSNH units as described in this report are preliminary. They indicate a lack of competitiveness across a wide range of assumptions. However, definitively assessing the costs and benefits of some options depend on reasonably firm value estimates. Securing that firmness requires more work than our report entailed. The Commission thus may also want to consider requiring an independent asset valuation process undertaken at a more detailed level.

We also recommend that consultation with legislative and executive leadership begin. We recommend that PSNH bring forth immediately proposals that would address a transfer of energy supply assets to an affiliate in accord with the optimistic views that the company has expressed with regard to the value of those assets.

Abundant natural gas supply has played a large role in holding electricity market prices low since "fracking" caused no less than a seismic market shift several years ago. Tumultuous world markets and a strong impetus for LNG exports from North America cannot be ignored or consigned to the past. Neither we nor anyone else can guarantee what will happen with natural gas availability or pricing over the horizon that we can see from here. Nevertheless, over the period during which PSNH's default service will experience the continued increases that we project, there is a very high level of confidence that circumstances will not change enough to reverse the growing burden. PSNH has consistently expressed contrary views, including very recently, but no information it has provided to us support that view. Neither do reports of U.S. government agencies or other sources available to us addressing energy issues over the next five to ten years.

It is always possible that the energy world that emerges will differ from the one(s) we anticipate now. Nonetheless, the strong consensus (apart from PSNH) that exists supports our strong conviction that planning across this five to ten year period is not only appropriate, but can be performed with a sufficiently strong belief that the combined value of PSNH's fossil/hydro fleet is not likely to change dramatically.

There are no simple answers. In conducting our investigation, we looked to explore a range of alternatives while being mindful of potential financial impacts to PSNH. Each alternative path brings with it questions, potential challenges, and possible legislative hurdles. One thing that is clear, however, is that parties want certainty. Whether it be PSNH customers, retail or wholesale competitors, or other stakeholder groups, continued uncertainty with respect to PSNH's generation ownership and its role in the competitive market makes planning future electricity purchase and other business decisions difficult, if not impracticable. We view this report as providing valuable information and recommendations to be used by all interested parties as PSNH, its customers, other stakeholders, and the State of New Hampshire as a whole, look to forge a constructive path that is in the collective best interests.

Historical Background of Restructuring Efforts

This report was prepared pursuant to the Commission's Order of Notice, opening Investigative Docket No. IR 13-020, issued on January 18, 2013. The Commission endeavored to respond proactively to changing conditions in the retail and wholesale electricity markets. PSNH occupies a unique position in the State's electricity market, given its size and geographic reach. This posture has been largely shaped by legislative action since the beginning of what is termed "restructuring" of the New Hampshire electricity market. PSNH has not remained passive in responding to the challenges and opportunities presented by restructuring, but is alone among New Hampshire's incumbent utilities in continuing to maintain a fleet of generation assets.

Historically, the production of electrical energy and its distribution along a system of wires to end-use customers, was considered a "natural monopoly." Competition within a given electrical utility's service area was thought to be impossible, or at least economically wasteful. State legislatures came to accept the rationale for allowing vertically-integrated monopolies of electrical generation and distribution within a specific service area as necessary to stimulate private investors to take the risk of spending massive sums to provide the new technologies. These investments were encouraged by states through the granting of utility franchises to power companies, which provided a stable customer base from which investment costs, operating costs, and a rate of return could be recovered.

By the 1990's, important developments resurrected the potential for the introduction of market competition within electrical utilities' service territories. A new enthusiasm for consumer choice and free-market dynamism encouraged efforts to break up utility monopolies, first in telecommunications, then in electricity, with the hope that lower costs and better service would result from the entrance of competitors into these closed markets. In general terms, it became clear that the distribution of electricity, that is, the provision of electric current to end users through the wires of the power supply network, would remain a natural monopoly. However, the proponents of electric restructuring believed that the supply and generation of electrical power could be opened to competition, on both the retail and wholesale levels. At the national level, the 1992 Federal Energy Policy Act was instrumental in expanding competition within wholesale power markets, and the Federal Energy Regulatory Commission's 1996 Open Access Rule required all electric utilities to provide open, non-discriminatory use of their transmission systems.

New Hampshire restructuring efforts began in earnest in June 1995, with the passage of Senate Bill 168, which created the Retail Wheeling and Electric Utility Restructuring Study Committee to study the issues associated with allowing retail customers choice. The Commission was also charged with establishing a pilot program for competitive retail purchasing of electricity. Following the success of this program, the Legislature enacted House Bill 1392 in May 1996, which initially established the restructuring statutory scheme in RSA Chapter 374-F, and directed the Commission to develop a statewide electric restructuring plan.

This plan was issued by the Commission on February 28, 1997, was entitled "Restructuring New Hampshire's Electric Utility Industry: Final Plan." Under the plan, and pursuant to RSA 374-F:3, vertically integrated electric utilities, including PSNH, were to unbundle retail services into generation, transmission and distribution components. The Commission plan also required distribution utilities, including PSNH, to sever corporate ties between competitive (supply/generation) and non-competitive (distribution) components by divestiture. The Commission's plan also required distribution utilities to sell generation and marketing services and to sell off any rights to obtain power under existing purchase contracts. The Commission's plan also outlined an approach to "stranded costs." However, this approach would lead to protracted litigation with the electric utilities. These challenges led to broad changes to the original design of restructuring in New Hampshire.

Within days of the issuance of the Commission's plan for restructuring, the parent company of PSNH, Northeast Utilities, PSNH, and the other franchised investor-owned electric utilities in New Hampshire filed suit in federal court to block the Commission's plan. After four years of effort, restructuring for PSNH resulted from settlement negotiations with supporting Commission and Legislature action. The Agreement between PSNH and Governor Shaheen, filed with the Commission in August 1999, still contemplated the full sale of PSNH's generation assets and the concurrent issuance of rate reduction bonds. The Legislature endorsed the issuance of the rate reduction bonds, and required PSNH's divestiture of its interest in Seabrook Station by its enactment of Senate Bill 472/RSA Chapter 369-B in June 2000.

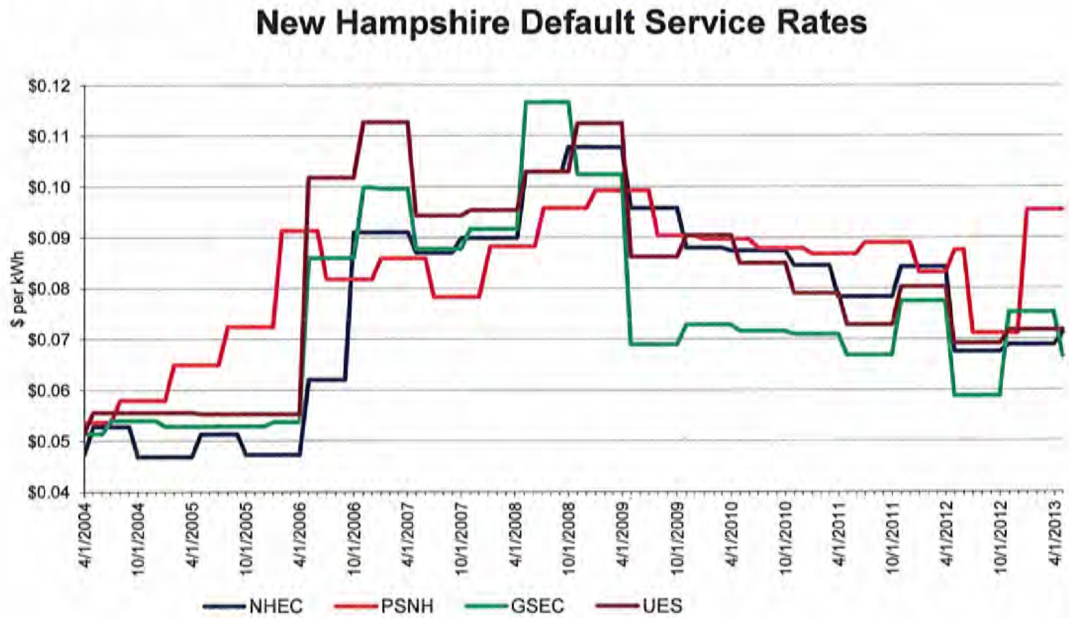
However, the Commission's, and Legislature's, original vision of a full divestiture of generation assets and supply business by the distribution utilities was scaled back. Most of these developments were in response to the 2000-2001 California energy crisis, in which the recently unbundled California electricity market had to contend with large price increases and repeated rolling blackouts. The concern stimulated by the California crisis led the Legislature to repeatedly delay the divestiture of PSNH's generation assets. In April 2001, the Legislature enacted House Bill 489, which amended the prior restructuring legislation to allow PSNH to provide transition supply service to customers until at least February 2006, as well as extending transition supply service for commercial and industrial customers until at least February 2005. House Bill 489 also allowed PSNH to keep its fossil-fueled and hydroelectric generation assets until at least February 2004 and to use them for the provision of supply service. PSNH divested only its interest in Seabrook Station, which went ahead as required by Senate Bill 472/RSA 369-B:3. The Legislature enacted RSA 369-B:3-a in April 2003, which provided that PSNH may not divest its fossil and hydro generating assets until April 30, 2006. RSA 369-B:3-a further provided that "...subsequent to April 30, 2006, PSNH may divest its generation assets if the [C]ommission finds that it is in the economic interest of retail customers of PSNH to do so, and provides for the cost recovery of such divestiture. Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the [C]ommission finds that it is in the public interest of retail customers of PSNH to do so, and provides for the cost recovery of such modification or retirement."

This is the statutory background for PSNH's current posture, in which PSNH faces increasing competitive pressure in its supply business, especially for commercial and industrial customers but also recently for residential and small commercial customers. PSNH has not elected to retire any of its major fossil-fueled or hydroelectric generating assets. As customer migration out of PSNH supply service continues to build, it places the burden of these assets' capital and operating costs on an ever-smaller customer base. From 2006 until roughly 2009, these pressures were mitigated by PSNH's relative market position as a low-cost supplier. The emergence of lower-cost supply competitors, relying largely on natural gas-fired generation, since 2009, however, have served to turn economic advantage to disadvantage when it comes to the PSNH generation assets.

Default Service Rates in New Hampshire

The Commission's order of notice stated that a major purpose of this investigation was to review "the market conditions affecting the default service of Public Service Company of New Hampshire (PSNH) in the near term and how PSNH proposes to maintain safe and reliable service to its default service customers at just and reasonable rates in light of those market conditions." Figure 1 below shows how PSNH's default service rate[5] has compared to the default service rates of other New Hampshire utilities since 2004[6]:

Figure 1: **New Hampshire Default Service Rates April 2004 – April 2013**



In comparing the default service rates charged by the various utilities, it is important to understand the difference between how PSNH's default service rate is calculated as compared to the other utilities. The New Hampshire Electric Cooperative (NHEC), Granite State Electric Company (GSEC) and Unitil Energy Systems (UES) have no generation assets and obtain supply for their default service load obligations by issuing requests for proposals (RFPs) and obtaining competitive bids from wholesale suppliers. PSNH, on the other hand, has an entirely different default service rate calculation paradigm—one that has a complex history and has evolved since the passage of Electric Utility Restructuring legislation[7] in 1996 as described above.

As stated, PSNH divested its entitlement to the power output from the Seabrook Station nuclear facility, but currently retains ownership of its fossil and hydro generating facilities. In addition,

[5] PSNH's default service rate is identified in its rate tariff as "Default Energy Service Rate DE." References to PSNH's rate as "default service" or "energy service" are used interchangeably throughout this report but refer to the same rate.

[6] Prior to 2004, PSNH's default service rate was set at rates fixed by statute. See RSA 369-B:3, IV(1)(B)(i).

[7] See RSA 374-F, *Electric Utility Restructuring*, et seq.

PSNH also currently purchases energy, capacity and/or environmental attributes from other generating facilities, pursuant to contracts or rate orders. PSNH uses its generating facilities and entitlements, along with supplemental wholesale market purchases, as necessary, to fulfill the requirements of RSA 369-B:3, IV(b)(1)(A), which states,

> From competition day until the completion of the sale of PSNH's ownership interests in fossil and hydro generation assets located in New Hampshire, PSNH shall supply all, except as modified pursuant to RSA 374-F:3, V(f), transition service and default service offered in its retail electric service territory from its generation assets and, if necessary, through supplemental power purchases in a manner approved by the commission. The price of such default service shall be PSNH's actual, prudent, and reasonable costs of providing such power, as approved by the commission.

PSNH's default service rates are thus calculated by combining its costs of owning and operating its generation fleet with the costs of necessary supplemental purchases, including entitlements pursuant to power purchase agreements. This situation is what was referred to in the Commission's order of notice as the "hybrid" situation. PSNH's default service rates are initially determined on an annual basis effective at the beginning of a calendar year, with a review and adjustment of the rate effective mid-year.

It is clear from Figure 1 that a significant swing in market conditions evidenced itself in mid-2009. PSNH's default service rate had been consistently below the default service rates of the other New Hampshire electric utilities since 2006. In 2009, the situation reversed and, with only very short-term exceptions, PSNH's default service rate has exceeded the others' rates since mid-2009. Given the differences in how the default service rates are calculated among the utilities, the position of PSNH's default service rate in relation to the other New Hampshire utilities demonstrates that, due to changes in the fuel and energy markets, PSNH's generation fleet transitioned from being a consistently below-market cost source to an above-market cost source. Those changing market conditions have resulted in changes to both the operation of PSNH's generating facilities and power purchasing strategies. PSNH's "as necessary" supplemental purchases initially were primarily to cover load requirements not met by its generation fleet. In recent years, the supplemental purchases have also included market purchases at prices lower than PSNH's generation cost, thereby reflecting reduced operation of its generation fleet.

PSNH's Generation Fleet

PSNH owns and operates the following electric generating units (ratings in megawatts (MW)):

Table 1

Fossil Plants	Winter Rating	Summer Rating
Merrimack Unit 1 (coal)	108.0	108.0
Merrimack Unit 2 (coal)	330.5	330.0
Newington (oil/natural gas)	400.2	400.2
Schiller Unit 4 (coal/oil)	48.0	47.5
Schiller Unit 6 (coal/oil)	48.6	47.9
Combustion Turbines		
Merrimack CT 1 (jet fuel)	21.7	16.8
Merrimack CT 2 (jet fuel)	21.3	16.8
Schiller CT (jet fuel)	19.5	17.6
Lost Nation (jet fuel)	18.1	14.1
White Lake (jet fuel)	22.4	17.4
Biomass Plant		
Schiller Unit 5	42.6	43.1
Hydroelectric Plants		
Amoskeag	17.5	16.8
Ayers Island	9.1	8.5
Canaan	1.0	0.6
Eastman Falls	6.5	5.6
Garvins Falls/Hooksett	14.0	12.5
Gorham	2.1	2.0
Jackman	3.6	3.6
Smith	15.2	11.7
Totals	**1149.9**	**1120.7**

The plants have differing fuel sources, thus, their operations can be affected quite differently depending on events taking place in the fuel and electricity markets. Planning for the operation of the plants needs to, and does, take those differences into consideration. Planning with respect to short-term market activities is one aspect, but long-term considerations also need to be taken into account.

Least Cost Integrated Resource Planning

The January 18, 2013 Order of Notice that opened this investigation stated, in part,

> …we find that certain portions of the Least Cost Energy Planning required by RSA 378:38 are best addressed in this investigation. Specifically, we find that RSA 378:38, III regarding assessment of supply options, and IX regarding assessment of the long- and short-term environmental, economic and energy price and supply impact on the State, should be addressed in this investigation rather than in PSNH's next least cost integrated resource plan.

Sections III and IX of RSA 378:38 were further addressed in the Commission's subsequent order regarding PSNH's most recent least cost integrated resource plan (Order No. 25,459 (January 29, 2013)):

> **C. Parameters for Next Full LCIRP Filing**
>
> We will now outline the expected parameters of the next full PSNH LCIRP filing, with specificity, to ensure clarity among PSNH, Staff, and other parties, regarding the future scope of the LCIRP process. These parameters relate to each of the elements of the LCIRP statute, RSA 378:38, I-IX. …For Element III, an assessment of supply options, we require that PSNH will address the impact of the evolving electricity market in the ISO-New England system and on migration of their Default Service customers (giving special attention to migration data and trends for the most recent three years prior to the LCIRP filing date, and projections for the next three [to] four years, based on this recent data) on PSNH's generating units and other supply options…The final Element IX relates to an assessment of the plan's long- and short-term environmental, economic and energy price and supply impact on the State which, as noted by PSNH, can be difficult to discern, especially in light of the events of the past decade. With the change from a vertically integrated utility to one that provides a mix of market-based and owned generation, we are scaling back the time frame of the required planning period, to three years. But with the long lead time and expense to comply with many environmental mandates, we are also requiring a better assessment of the impact of those regulations that have been noticed in federal or state registers. To satisfy Element IX, we will require PSNH to present, as part of its next full LCIRP filing, its analysis of the LCIRP's impact on both long- and short-term environmental, economic and energy price and supply impact on the State.
>
> **D. Timing of Next LCIRP Filing, Waiver Pursuant to RSA 378:38-a**
>
> The recently-opened Commission investigation in Docket No. [IR] 13-020, regarding the market conditions affecting PSNH and its Default Service customers, and the impact, if any, of PSNH's ownership of generation on the New Hampshire competitive electric market, may address some of the parties' concerns in this LCIRP proceeding more directly. In order to avoid redundancies

> and resultant unnecessary administrative burden, we therefore waive, pursuant to RSA 378:38-a, PSNH's requirement to file a full LCIRP filing for the upcoming 2013 LCIRP round. However, as specified by RSA 378:38-a, PSNH must file, no later than September 3, 2013, its plans relating to transmission and distribution to satisfy its abbreviated 2013-round LCIRP filing requirements. (The recommendations outlined in Section C above should be viewed as guidelines for the development of the Company's next full LCIRP filing, which will be made subsequent to the resolution of the DE 13-020 investigation, and after PSNH's abbreviated 2013 LCIRP filing).[8]

The Commission waived the requirement for PSNH to file a *full* LCIRP in 2013, with the 2013 LCIRP to cover only transmission and distribution planning. With respect to PSNH's generation, supply options and the long- and short-term environmental, economic and energy price and supply impact on the State, it is apparent that the Commission determined that it would be much more instructive to use the results of this investigation to guide recommendations for future planning decisions. Thus, this report is not a substitute for PSNH reporting on its planning activities, as directed by the Commission.

Assessment of Supply Options and Long-Term and Short-Term Purchasing Alternatives

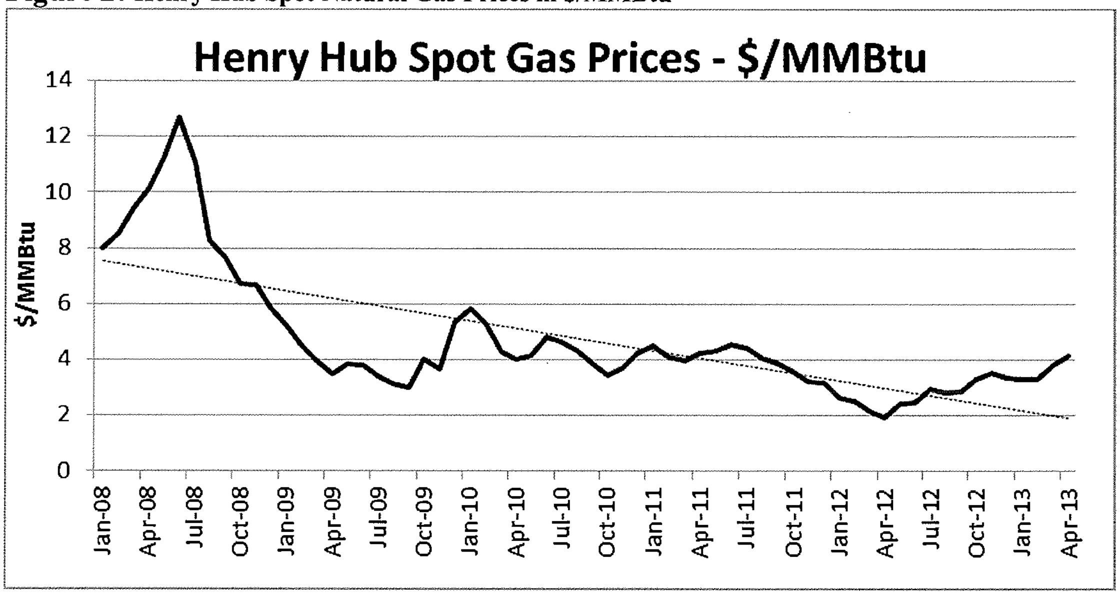
An assessment of PSNH's supply options and long-term and short-term purchasing alternatives for least cost planning purposes necessarily first involves an assessment of the status of PSNH's continued ownership and operation of generating facilities. To do so, it is important to understand the current position of PSNH's generating plants in the New England market as well as the near-term and long-term implications of changes in energy and fuel markets and other economic factors.

[8] Order No. 25,459 (January 29, 2013) at 19-21.

Energy Markets Outlook

North American energy markets have changed markedly over the last several years, driven in major part by a significant decrease in natural gas prices since 2008[9] (Figure 2). The chart displays the monthly average spot gas price at Henry Hub[10] in $ per million Btu and the linear trend line for this period. The effect of lower natural gas prices has been felt in every U.S. region, including the Northeast.

Figure 2: **Henry Hub Spot Natural Gas Prices in $/MMBtu**



Source: U.S. Energy Information Administration)

One important impact of these historically low gas prices is a reduction in wholesale electric power market prices (Figure 3). Figure 3 displays the average monthly wholesale energy price for ISO-NE's New Hampshire Zone[11]. The data represent the average of all hours (peak and off peak) for each month in the Day-Ahead Market. The overall trend (as displayed by the linear trend line on the chart) has been a reduction in energy prices, with the exception of January of 2013. This power price outlier reflects gas price spikes due to delivery constraints that were experienced during the winter of 2013.

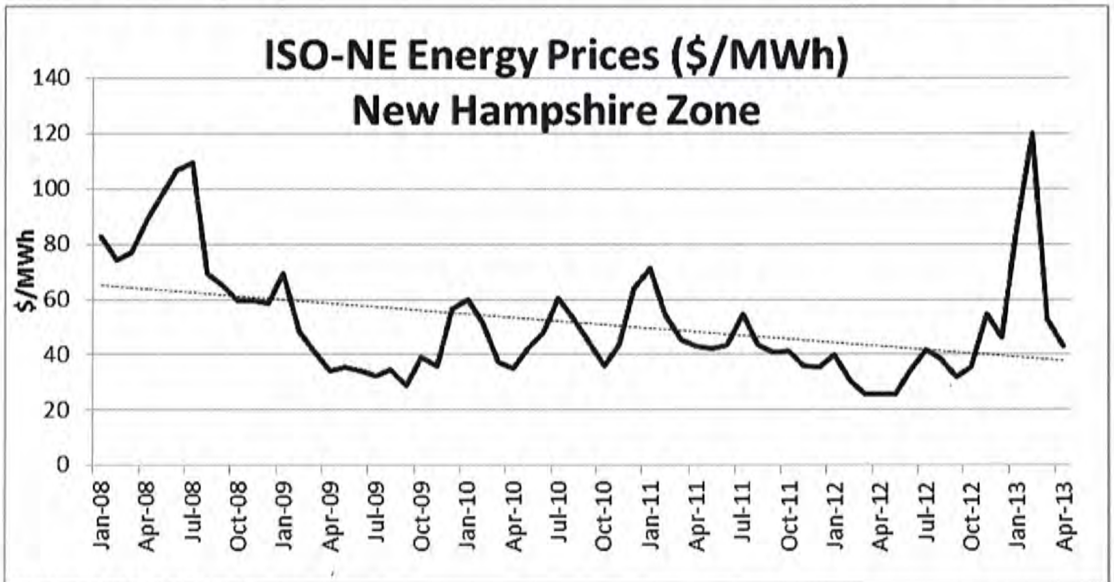
Natural gas prices affect all electric energy prices, but most directly affect peak energy prices. Gas-fired generation sets the price more frequently in peak periods. Therefore, the greatest impact of lower gas prices has been an overall reduction in what would be expected of peak energy prices, and to a lesser degree off-peak energy prices.

[9] U.S. Energy Information Administration.

[10] Henry Hub is a hub on the natural gas pipeline system used as a pricing point for natural gas futures contracts on the New York Mercantile Exchange (NYMEX).

[11] ISO-NE historical prices from www.iso-ne.com.

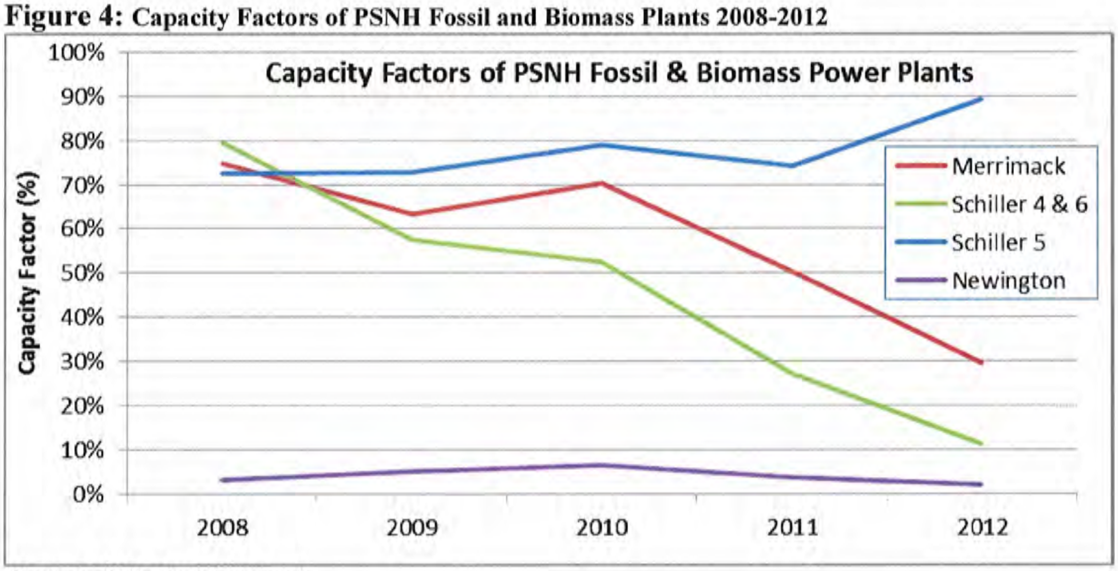
Figure 3: **ISO-NE Historical Day-Ahead Energy Prices for the New Hampshire Zone in $/MWh**



(Source: ISO-NE)

A key indicator of generating unit performance is capacity factor, which is the amount of energy produced during a specific time period (typically a year or a month) as a percentage of the maximum possible output by the unit for that same period. Ultimately, capacity factor is a good indicator of competitiveness and the ability to produce energy revenues, and is a key component of asset value. Figure 4 shows the trends in capacity factors of PSNH's fossil and biomass units from 2008 – 2012.

Figure 4: **Capacity Factors of PSNH Fossil and Biomass Plants 2008-2012**



(Source: SNL Data Services)

Two of the key drivers of capacity factor are the energy prices in the market the asset serves, and the fuel cost of the specific generating asset. As shown above, the coal units at Merrimack Station and Schiller Station have experienced a sharp downward trend in operation over the last few years, while the biomass unit (Schiller Unit 5) has been steady and actually increasing. Newington Station's minimal operation, however, reflect the unit's relative indifference to changes in fuel and energy markets. In short, asset values generally follow the combination of power market prices and fuel prices. In simple terms, the higher the market prices relative to the fuel costs, the better for a given asset. In the case of PSNH coal plants, the situation has been the opposite, given the drop in electric wholesale energy prices in ISO-NE. We will explore this phenomenon further in the Asset Value section.

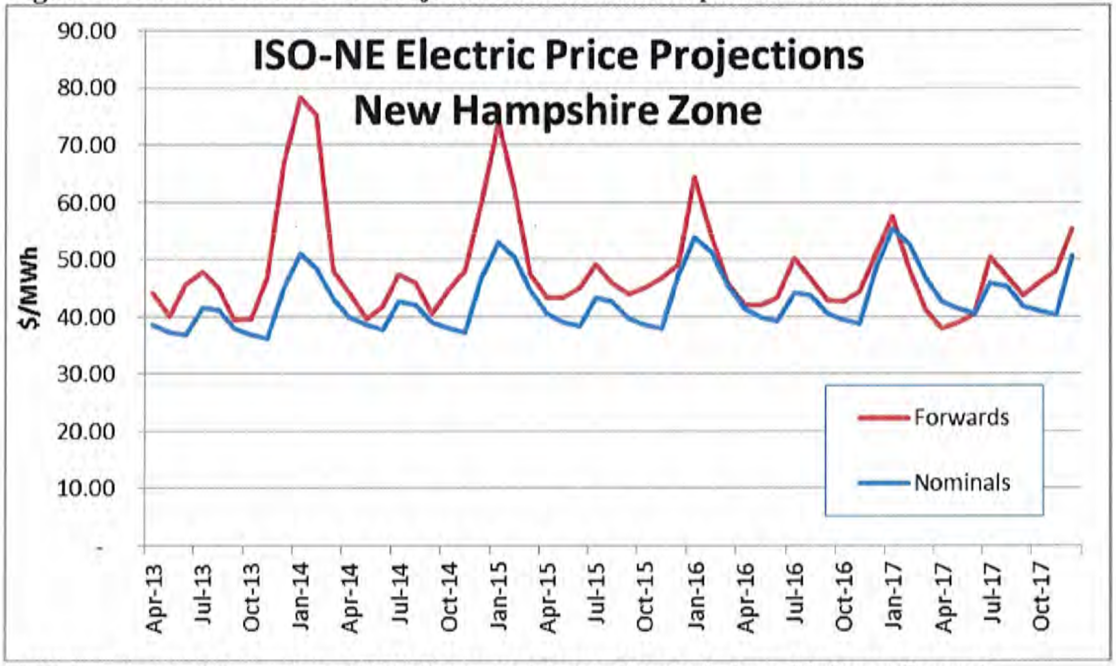
ISO-NE Electricity Price Forecast

Key to the assessment of a generating unit is the price of energy in the market it serves. Figure 4 displays projections of wholesale electric prices for the New Hampshire zone of ISO-NE.[12] Figure 5 shows forward prices for energy in $/MWh, plotted against a "power nominal" curve.[13] This curve represents a projection of wholesale energy prices based on forward gas prices (at Henry Hub) and historical spark spreads. The result is a long-term outlook of energy prices based on established, highly-liquid forwards for gas at Henry Hub.

It is worth noting the disparity between forward energy prices and the Power Nominals shown in Figure 5. In the first three years of the projections, forward prices are substantially higher than those of the Power Nominals. This result is explained by the fact that Power Nominals do not reflect the very high transportation component of natural gas delivered to New England generators, because they are based on the historical relationship between power prices and Henry Hub gas. Power Nominals therefore do not capture the short-term price spikes to be expected for the next three years in New England winter and summer months. The projections converge after this period, which indicates that traders do not foresee a long-term energy price premium for New England gas transportation issues.

[12] CME Group NYMEX futures, March 2013.
[13] Power Nominals is a third party forecast service provided by RisQuant.

Figure 5: **ISO-NE Electric Price Projections for the New Hampshire Zone in $/MWh**



(Sources: Forward Prices from CME Group and Power Nominals from RisQuant Energy)

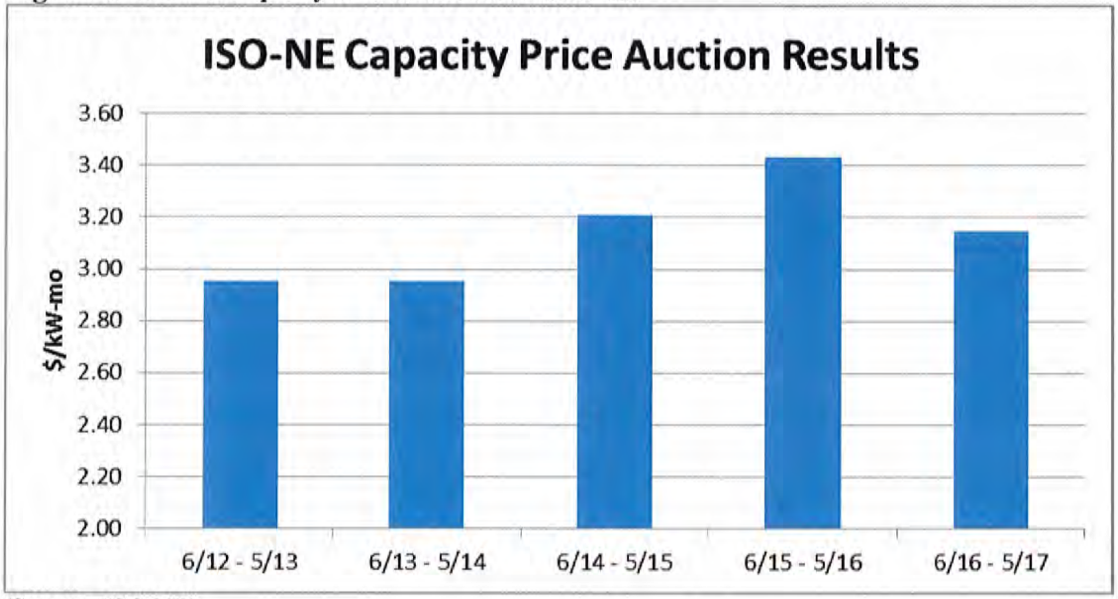
The energy price projections are consistent with the market's expectations that New England gas prices will no longer experience massive transportation-related price spikes after 2016. After that period, the long-term energy prices become flat.

Flat energy prices and low gas prices are not favorable for coal plants like Merrimack and Schiller, which are considered to be a hedge against the volatility of natural gas. The continuation of low gas prices and the corresponding low energy prices will continue to keep the PSNH coal units from generating at a high capacity factor. Further, they are a key driver in the asset value ranges calculated in the Asset Values section.

ISO-NE Capacity Prices

Electricity supply sources are also eligible to receive capacity market revenues through the Forward Capacity Market. The Forward Capacity Market (FCM), operated by ISO-NE, is the mechanism in which ISO-NE procures enough resources to meet its forecasted demand. The FCM is also intended to provide compensation for the capacity cost of existing generation, imports, and demand resources, and to attract new resources into the market. Forward capacity prices are derived by ISO-NE auctions, and the results of those auctions are displayed in Figure 6. Prices throughout the period of our assessment fall in the range of $3.00-3.50 per kW-month, or $36-$42/kW-yr.

Figure 6: **ISO-NE Capacity Auction Results in $/kW-mo**



(Source: ISO-NE)

After May 2017 the capacity prices are unknown and may actually be lower due to the removal of a floor price from the auction structure. Low-capacity factor units such as Newington and PSNH's combustion turbines derive their primary value from revenues received in the capacity market which, therefore, enhances asset value. This is particularly the case if the revenues generated from the capacity market are not offset by high fixed O&M costs, which is the case for PSNH peaking units, as discussed in more detail in the asset value section.

The New England Natural Gas Market

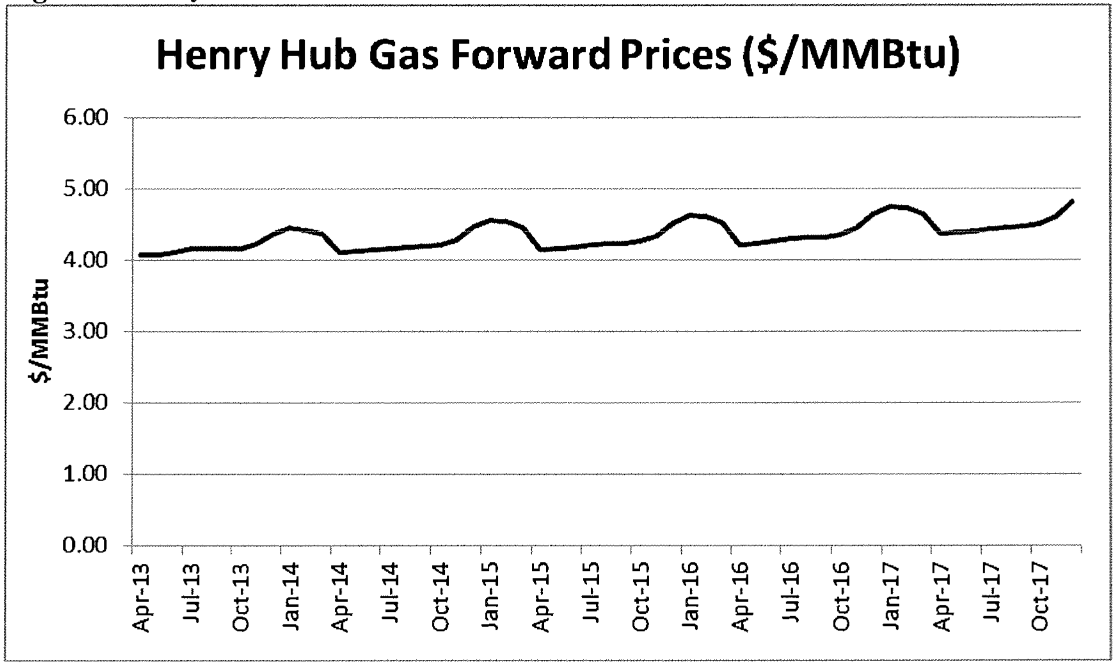
The U.S. Department of Energy, Energy Information Administration's 2013 Reference Case forecast shows Henry Hub prices about constant through 2015, then experiencing a significant increase (plus 16%) in 2016, followed by steady 4 to 7% (nominal) increases through 2025.

The futures market shows annual average basis differential between Henry Hub and the Algonquin City Gates (Boston), declining, from 99 cents per MMBtu in 2013 to 47 cents per MMBtu in 2015.

We see no current reason for the basis differential to increase after 2015. Therefore the outlook is for annual average natural gas prices in New England to decline from about $4.35 MMBtu this year, to about $3.80 MMBtu in 2015. After 2015, a bit of a jump is expected -- to $4.33 MMBtu in 2016, then up by 4 to 7% per year to 2025.

For reference, Figure 7 displays the forward prices for Henry Hub gas from 2013-2017. As expected, the prices, while seasonal, are relatively flat and remain low relative to historical prices.

Figure 7: Henry Hub Natural Gas Forward Prices in $/MMBtu



(Source: CME Group)

PSNH Coal Price Outlook

Merrimack Station

Merrimack Station's cyclone fired boilers use a low ash fusion coal that is typically not forecast by entities such as EIA and SNL.[14] Accordingly, coal prices for this plant are difficult to predict. PSNH coal prices for 2013 are based on existing contract prices. Prices for 2014 and 2015 are based on a combination of contract prices and ICAP[15] forecasts, provided by PSNH, and prices for 2016 are based on a current ICAP forecast.

A subset of Merrimack's fuel prices for 2013 and 2014 includes only existing coal contract prices. These prices are higher than market prices in both years for similar coal, based on data from the Energy Information Administration. Because the overall PSNH price estimates for these years are favorable, we are assuming that PSNH is planning to supplement existing, high priced contracts for these two years, with market prices that are currently low.

In summary, the PSNH coal prices for the years 2013 through 2016 are consistent with estimates of market prices from various sources. These prices do not provide any strategic or operational advantage to PSNH's units, but this information helps to frame the overall discussion of Merrimack's competitive position against low gas prices.

It is worth noting that PSNH has recently installed at Merrimack Station a wet flue gas desulfurization (FGD) scrubber for SO_2 removal. Accordingly, PSNH was asked about the ability to use different, high-sulfur fuels at Merrimack given the SO_2 control technology.

[14] SNL Financial is a provider of industry data and analysis.

[15] ICAP Energy is a broker of fuels and other commodities.

PSNH's response was that it does not see a future with significantly different fuel types used, given the parameters required of a cyclone-fired boiler. Further, PSNH asserted that it could take over a year or more to perform testing and implementation of any new fuel or blend for Merrimack.

Schiller Station

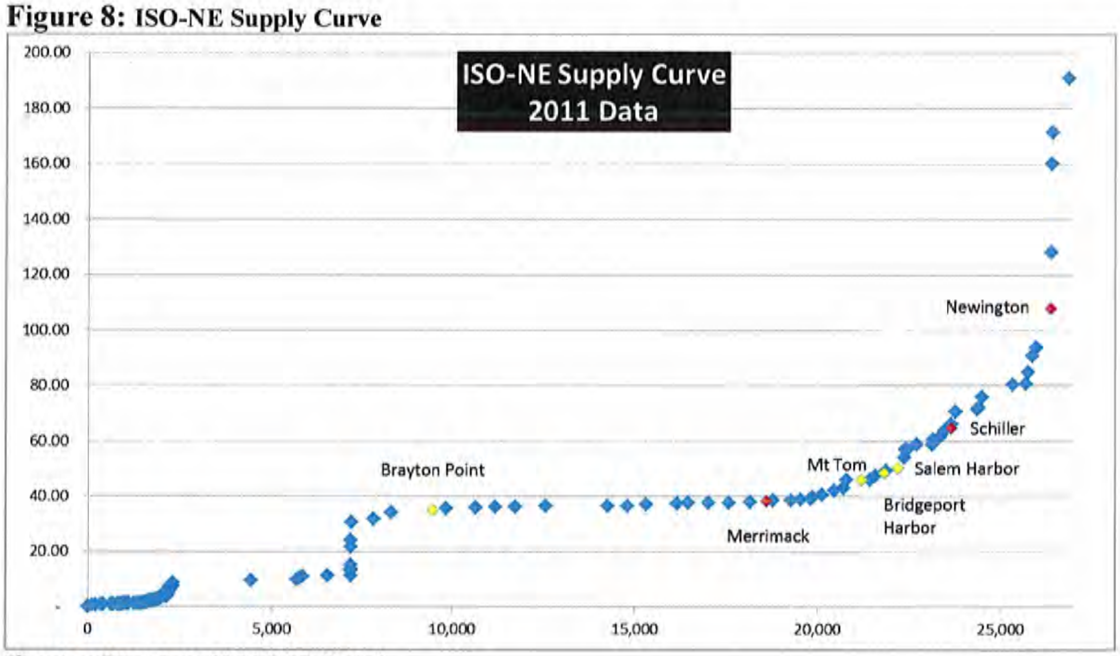
There are no active coal contracts for Schiller Station, other than 560,000 tons of coal remaining to be delivered under a 2008-2011 contract due to supply difficulties encountered at the source mine. The only future forecast coal deliveries to Schiller are for 34,000 tons of coal in 2013.

However, PSNH's forecast of coal prices for Schiller is consistent with market forecasts through 2016. Future fuel prices are based on a philosophy of fuel flexibility to burn either oil or coal at units #4 and #6 (each 50MW) depending on market changes in fuel costs.

PSNH Asset Competitive Position

Based on regional fuel prices and individual unit heat rates (Btu/kWh), a supply curve[16] was developed and is displayed in Figure 8. The supply curve calculates an estimate of dispatch cost (including fuel and variable O&M) provided by SNL for all power plants operating in ISO-NE. While ISO-NE is broken down into zones for pricing purposes, the supply curve is for the entire ISO-NE region.

Figure 8: ISO-NE Supply Curve



(Source: Based on 2011 SNL Data)

On the supply curve, each generating asset within ISO-NE is symbolized by a diamond, which plots the plant on the y-axis by dispatch cost ($/MWh). Each unit is "stacked" from lowest to highest cost (left to right). Based on cost, the plants at the left end of the curve would be expected to be dispatched before the plants to the right of them on the curve. PSNH's

[16] Developed from SNL data for the 2011 time period.

Merrimack, Schiller and Newington plants are displayed as red diamonds, and non-PSNH coal plants are displayed as yellow diamonds.

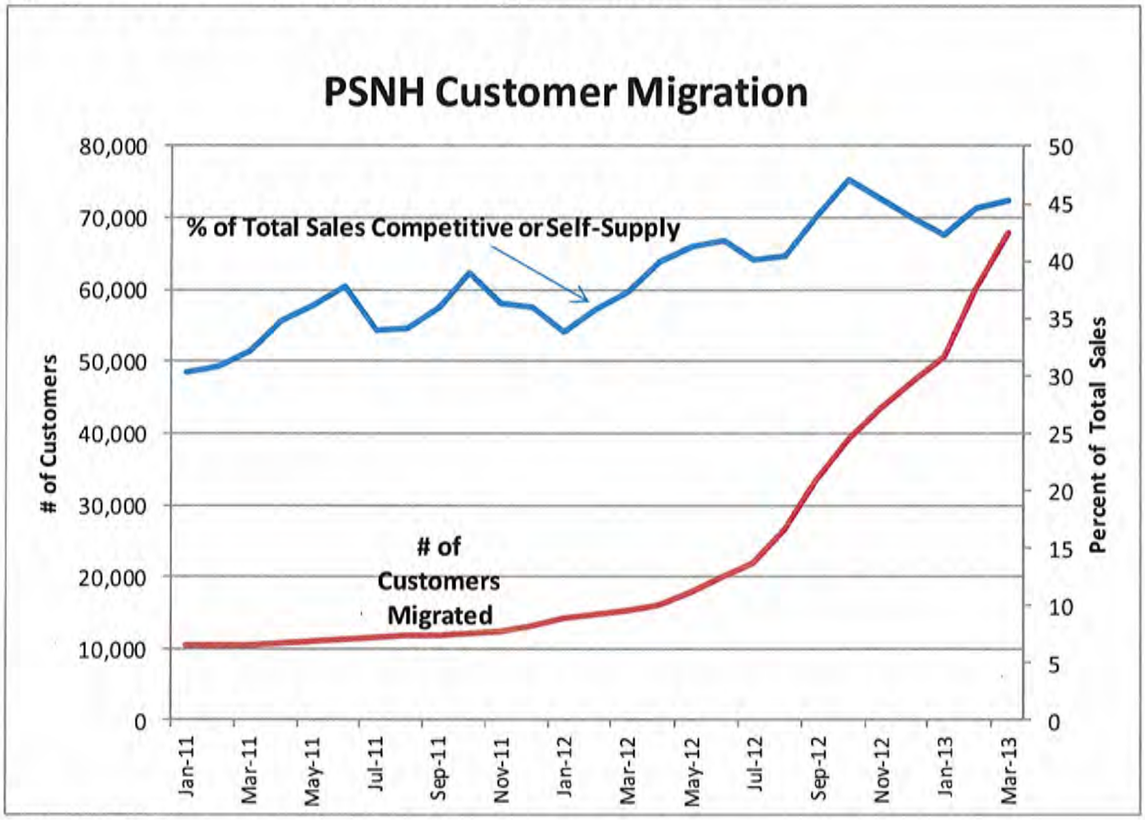
This supply curve highlights that, from a competitive standpoint, Merrimack is substantially behind Brayton Point in the dispatch order, and that Schiller and Newington are even further behind. This circumstance is noteworthy. Brayton Point (shown as the most economic coal plant in ISO-NE by this supply curve) recently sold for just $35 per kW.

Current Conditions and Rate Impacts of Various Factors

Status of Retail Electric Competition in New Hampshire

Retail electric competition in PSNH's service territory today differs starkly from the situation a few short years ago, especially for the residential and small commercial customers. It is important to understand how the situation has evolved. Figure 9 depicts customer migration to competitive supply options in PSNH's service territory since the beginning of 2011:[17]

Figure 9: **PSNH Customer Migration January 2011 – March 2013**

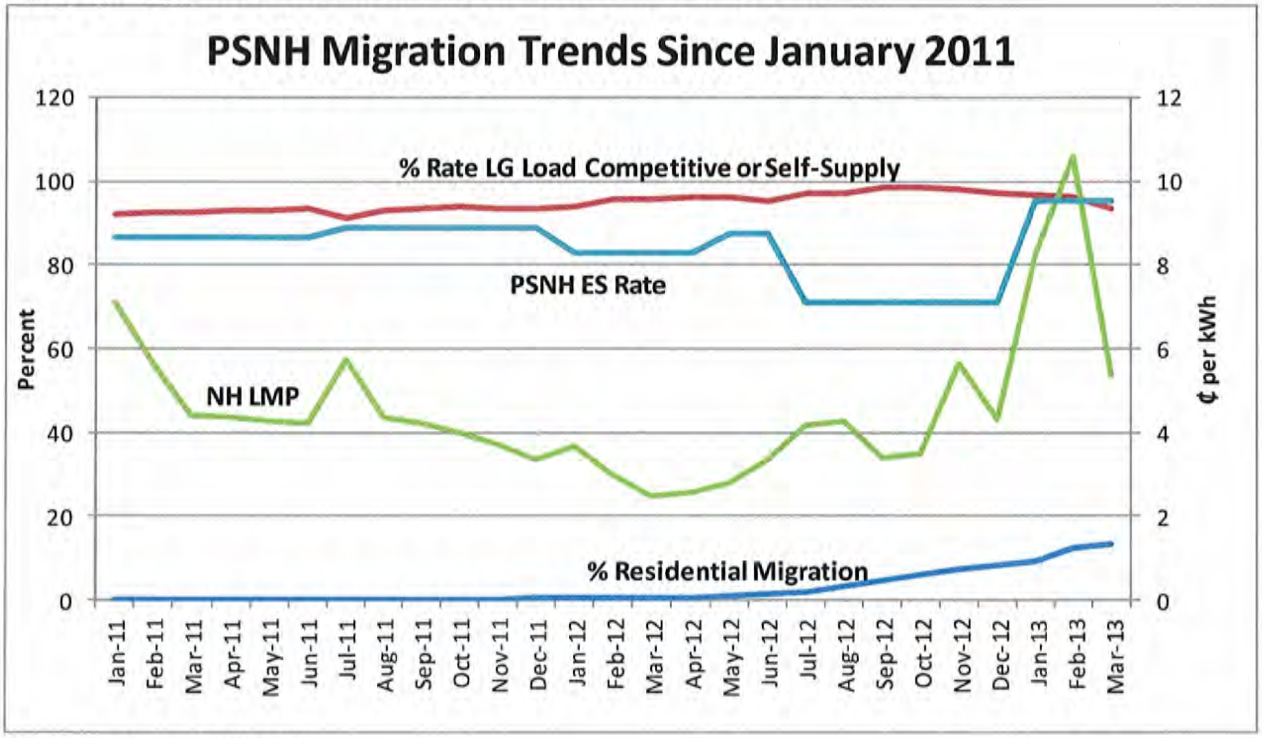


(Source: PUC)

[17] The period beginning with January 2011 was used as it captures both before and after residential customer migration began to become significant.

The number of PSNH customers choosing competitive or self-supply[18] options has been steadily increasing. Figure 10 breaks down the data further:

Figure 10: **PSNH Migration and Price Trends January 2011 – March 2013**



(Sources: PUC and ISO-NE)

The preceding shows that migration in PSNH's Rate LG[19] class has remained relatively constant at more than 90 percent of load. Migration in the residential class has been steadily increasing since the second quarter of 2012. Not coincidentally, that is also the time when the largest gap existed between PSNH's energy service rate and New Hampshire locational marginal price (LMP).[20] Excepting the well-documented natural gas price spike in January and February 2013, PSNH's energy service rate has been above the prevailing market prices.

Table 2 shows that changing market dynamics have led to an influx of applications for registration as competitive power suppliers and electricity aggregators (end of year totals):

[18] Self-supply includes self-generation and direct market purchases.

[19] Rate LG applies to PSNH's largest commercial and industrial customers.

[20] The LMP represents a wholesale price rather than a retail price paid by residential customers. The LMP, however, is a major factor in the retail prices offered by competitive suppliers and is used for purposes of the chart to demonstrate the relationship of PSNH's energy service rate to then-existing market prices.

Table 2

	Competitive Suppliers	Aggregators
2010	8	44
2011	12	57
2012	15	86
2013 (to date)	18	92

Competitive suppliers until recently have served only non-residential customers. PSNH's formerly below-market default service rate made its residential market unattractive to competitors. PSNH's default service rate is now above-market, providing opportunities for competitive suppliers.

Migration of residential customers in the territories of the other New Hampshire electric utilities has been nominal. Current residential migration statistics in those territories have been consistently extremely low (less than 1 percent). A major difference lies in how default service is procured and priced for those other utilities. Those distribution utilities obtain competitive bids to supply their respective default service loads. The resulting retail rates therefore more closely follow the trends in market prices. Opportunities for retail competitive suppliers to attract residential customers away from default service in those territories are limited. If PSNH were to no longer own its generation fleet, and PSNH were then to procure its default service requirements as do the other New Hampshire distribution utilities, it may be that existing opportunities for competitive suppliers in PSNH's service territory would diminish, given that PSNH's default service rate would more closely mirror prevailing market prices. Whether such a decrease in competitive opportunities would be short-term or long-term or beneficial for the long-term competitive market environment are issues that depend on one's point of view. The recently vibrant competitive market for residential customers in PSNH's service territory results directly from PSNH's current situation of owning and operating its generation fleet. If PSNH no longer owns generation, what happens to that market?

Given the increased customer migration being experienced by PSNH, it is important to take a look at some of the major cost drivers and their impacts on PSNH's default service rate.

Rate Scenarios Given Various Assumptions

PSNH's older, inefficient generation fleet with high fixed costs causes PSNH's default service rate to be above-market over almost all of a year. Whether that situation is likely to continue for us is the key question. In order to examine that issue, we requested PSNH to run its energy service rate model using various assumptions. Using PSNH's energy service model as the base was important because it is the same model that historically has been used to calculate the energy service rate, including the calculation that resulted in the current 9.54 cents per kWh rate[21] (8.56

[21] On May 2, 2013, PSNH filed a request for an adjustment to its energy service rate, effective July 1, 2013, to 8.98 cents per kWh (8.00 cents per kWh (non-scrubber) + 0.98 cents per kWh (temporary scrubber recovery)). That rate calculation was estimated as of the time of the filing and is scheduled to be updated prior to the June 20, 2013 hearing.

cents per kWh (non-scrubber) + 0.98 cents per kWh (temporary scrubber recovery)). Using the 9.54 cents per kWh rate as the starting point for a base case, adjustments were made to remove transitory issues, i.e., a prior year under-collection of costs and the return on the energy service deferral that were included in the calculation of that rate. These changes reduce the "base case" rate to 9.32 cents per kWh. We requested model runs that address the following range of assumptions:

- Inclusion of the power purchase agreement with Burgess BioPower
- Customer migration at current level[22]
- Customer migration at 50% of total load
- Customer migration at 60% of total load
- Current (partial) Scrubber recovery (temporary rate adder)
- Scrubber at zero cost recovery
- Scrubber at full cost recovery
- Current natural gas prices
- Increase in natural gas costs of 10%
- Increase in natural gas costs of 25%
- Current coal prices
- Decrease in coal costs of 10%

The various factors and assumptions were analyzed both in isolation and in numerous combinations. The purpose of this analysis was not to develop a precise estimate of PSNH's energy service rate going forward, nor was it to predict whether any particular event may or may not happen.[23] Rather, the focus was on the magnitude of the impact of each of the factors on the resulting energy service rate calculation. The rate scenarios involving "no scrubber recovery" and "full scrubber recovery" were used solely to bound the scrubber rate impact at minimum and maximum levels and should not be viewed in any way as indicating predetermined arguments or positions with respect to scrubber cost recovery. The rate calculations were performed only for a single year, using 2013 as the base year. Attempts to forecast the energy service rate for future years becomes very complicated as numerous changing assumptions would be involved. The factors and assumptions were selected based on changes from the conditions that existed at the time the calculations underlying the 2013 energy service rate were performed. Given constantly changing market conditions, changes in some of the factors may now appear more or less likely.

The calculations are more useful in assessing near-term impacts rather than long-term impacts or rate trends. However, the fuel and energy price forecasts discussed elsewhere in this report provide an indication of the directions factors such as fuel prices and customer migration may be headed. Many other alternate scenarios and changing factors can be posited, but it is important to keep in mind that the focus should be on where rates may be headed based on a range of

[22] "Current level" refers to the 42.5% migration level as of the end of October 2012 that was used to calculate the current 2013 energy service rate. On May 30, 2013, PSNH submitted a response to a discovery request in DE 12-292 that showed the migration rate had increased to 49.9% of total load as of the end of April 2013.

[23] For example, while there are differing views on whether a cooling tower may ultimately be required to be installed at Merrimack Station and, if so, when that would occur and how much it would cost, if a cooling tower were required it would increase PSNH's default service rates above the level that would otherwise be in place at that time.

potential outcomes. Table 3 presents, in summary form, the results of the various rate scenarios, compared to the base case scenario of 9.32 cents per kWh:

Table 3

Case #	Scenario	Migration Rate	Scrubber Recovery	Gas Prices	Coal Prices	Berlin @ PUC PPA levels (a)	ES Rate ¢/kWh	Difference from Base Case ¢/kWh
1	Base w/ Berlin PPA	Current	Yes-current	Current	Current	Yes	9.33	0.01
2	High Migration Case 1	50%	Yes-full	Current	Current	Yes	10.17	0.85
3	High Migration Case 2	60%	Yes-full	Current	Current	Yes	11.06	1.74
4	Scrubber	Current	No	Current	Current	Yes	8.35	(0.97)
5	High Gas Case1	Current	Yes-full	+10%	Current	Yes	9.92	0.60
6	High Gas Case 2	Current	Yes-full	+25%	Current	Yes	10.15	0.83
7	Low Coal	Current	Yes-full	Current	-10%	Yes	9.59	0.27
8	Combinations	50%	Yes-full	+10%	-10%	Yes	10.15	0.83
9		50%	Yes-full	+25%	-10%	Yes	10.20	0.88
10		50%	No	+10%	-10%	Yes	8.59	(0.73)
11		50%	No	+25%	-10%	Yes	8.64	(0.68)
12		60%	Yes-full	+10%	-10%	Yes	10.90	1.58
13		60%	Yes-full	+25%	-10%	Yes	10.78	1.46
14		60%	No	+10%	-10%	Yes	8.95	(.37)
15		60%	No	+25%	-10%	Yes	8.83	(.49)

(a) "Berlin @ PUC PPA Levels" means the Burgess BioPower PPA at the cost rates and purchase levels included in Order No. 25,213 (April 18, 2011) in Docket DE 10-195.

Case #1 through Case #7 involved isolated changes as compared to the 9.32 cents per kWh base case. Case #8 through Case #15 postulate various combinations of the changing factors. We recognize that certain combinations of changing factors, by their nature, would be more likely to occur simultaneously than other combinations. The above scenarios, however, represent a reasonable range of potential outcomes for the purpose of trying to gauge the direction of PSNH's default service rate.

We observed the following about the drivers of change in PSNH's default service rates:

- All scenarios result in a default service rate above the rates currently offered by competitive suppliers.
- The Burgess BioPower PPA should have minimal impact on the energy service rate, especially during the first two years, due to the significant pricing discount (50 percent) for the Class I renewable energy certificates.
- The scenarios showing a decrease from the base case all involve "no scrubber recovery" as the current temporary rate adder would be removed from the default service rate.

The results of the scenarios bear on the question of whether there is a point at which the default service rates would be considered no longer just and reasonable even though they are cost-based rates. If so, identifying what point and how it would be determined becomes critical. Default service was originally intended as a form of backstop or provider-of-last-resort service. Thus, one can also ask whether it matters if the rate has a significant variance from prevailing market prices.

Impact of Scrubber Recovery

Currently, PSNH has been allowed to begin recovery of a portion of its Scrubber costs, on a temporary basis, at the rate of 0.98 cents per kWh.[24] That rate is added to the non-Scrubber default service rate and is charged only to those customers who take PSNH's standard default service. As the rate adder was implemented on a temporary basis, pursuant to RSA 378:27, any difference (higher or lower) between the final determination of the level of permanent rate recovery versus the level of temporary rate recovery will ultimately be reconciled through default service rates.[25] There is currently a proceeding before the Commission to review PSNH's costs of complying with RSA 125-O:11, et seq, Docket DE 11-250. While it is currently unknown when the proceeding will be completed and what the final resolution will be, any discussion of the rate impacts of the Scrubber can be bounded by using scenarios where a) there is zero cost recovery, and b) where there is 100% cost recovery. As noted above, those two cost options were included in the various rate scenarios PSNH was requested to run.

To develop an estimate of the impact of full Scrubber cost recovery, the starting point is PSNH's estimate of the annual revenue requirement associated with the Scrubber. In the temporary rates portion of DE 11-250, PSNH testified that the annual Scrubber revenue requirement was $55.5 million. The 0.98 cents per kWh temporary adder approved by the Commission in DE 11-250, while involving the use of a 66 percent Temporary Rate Cost Percentage, effectively provides for more than 66 percent recovery of the annual revenue requirements associated with the Scrubber. The derivation of the 0.98 cents per kWh rate had the following components:

- 66 percent of the annual revenue requirements ($55.5 million x 66 percent = 36.6 million)
- Unrecovered Scrubber costs from 2011 = $13.1 million

Those two components totaled $49.7 million which, when divided by the then-estimated annual kilowatt-hour sales, produce a rate increment of 0.98 cents per kWh. PSNH, however, has since experienced increased customer migration, which produces lower annual default service sales. Its May 2, 2013 filing in Docket DE 12-292 (the mid-year review of its energy service rate) estimated its 2013 annual sales at 4,272,414 megawatt-hours. That level of sales supports PSNH collecting approximately $41.9 million in Scrubber cost recovery during 2013. Assuming the temporary rate adder is in effect for the duration of the year, that leaves approximately $13.6 million of 2013 Scrubber costs unrecovered. In addition to that estimated $13.6 million of unrecovered 2013 costs, PSNH has also stated that it had $50.1 million of unrecovered deferred costs associated with the Scrubber as of December 31, 2012. Assessing the impact of the costs of the Scrubber, assuming full cost recovery, the following amounts, therefore, require consideration:

[24] Order No. 25,346 (April 10, 2012).

[25] Pursuant to RSA 125-O:18, "If the owner [of Merrimack Station] is a regulated utility, the owner shall be allowed to recover all prudent costs of complying with the requirements of this subdivision in a manner approved by the public utilities commission. During ownership and operation by the regulated utility, such costs shall be recovered via the utility's default service charge. In the event of divestiture of affected sources by the regulated utility, such divestiture and recovery of costs shall be governed by the provisions of RSA 369:B:3-a."

- Annual unrecovered costs of $13.6 million
- Accumulated unrecovered costs of $50.1 million as of December 31, 2012

The currently estimated level of 2013 sales would require the temporary rate adder of 0.98 cents per kWh to increase to approximately 1.30 cents per kWh in order to recover fully the $55.5 million annual revenue requirements. In addition, 1) the $50.1 million of unrecovered Scrubber costs as of December 31, 2012, plus 2) any additional unrecovered costs that accrue between December 31, 2012 and 3) the implementation of any Scrubber-related rate increase, would need to be factored into rates, possibly by means of a multi-year amortization of the costs.

For example, assume a scrubber-related rate increase effective January 1, 2014, a three-year amortization of previously unrecovered costs and energy service sales at the current 2013 estimated level. The estimated unrecovered costs at that time would be $63.7 million ($50.1 million + $13.6 million). A three-year amortization would result in $21.2 million to be recovered annually. The overall Scrubber rate impact would then be approximately 1.80 cents per kilowatt-hour (an increase of 0.82 cents per kilowatt-hour above the current 0.98 cents per kWh temporary rate adder).

Rate Impact of PPA with Burgess BioPower

Another item specifically identified in the order of notice as a factor to be considered is the expected impact on default service rates resulting from the power purchase agreement PSNH entered into with the currently under construction Burgess BioPower biomass generating facility.[26] Case #1 listed in the previous table changed the base case only by including the Burgess BioPower contract for a full year. The far right column shows the rate impact at only 0.01 cents per kWh. This marginal increase is due in large part to the pricing structure established by the Commission, particularly the pricing of the Class I Renewable Energy Certificates (RECs)[27] to be purchased under the agreement. During the first two years of the twenty-year agreement, the RECs are priced at 50% of the Class I Alternative Compliance Payment (ACP)[28], followed by five years at 80%, five years at 75%, five years at 70% and the final three years at 50%. The base energy price of $69.80 MWh is above current market energy prices, but that is offset by the below-market cost of the Class I RECs.[29] As a point of reference, the 2013 Class I ACP is $55.00/REC. By purchasing a maximum of 400,000 Class I RECs under the PPA at a 50% discount, PSNH and its customers save up to $11,000,000 per year over the first two years of the contract when compared with PSNH paying the ACP price for the same quantity.[30]

[26] See Docket DE 10-195.
[27] One megawatt-hour of generation from a qualifying renewable facility equals one REC.
[28] Pursuant to RSA 362-F:10, II, to the extent an electricity provider does not acquire sufficient RECs to meet the annual requirements of a particular REC Class, it may meet those requirements by making payments into the Renewable Energy Fund at rates established by that statute and subsequently updated by the Commission.
[29] There are many other factors involved in the pricing of the Burgess BioPower PPA that will impact any detailed analysis of the PPA's impact on rates in future years, including limitations on the annual energy output and RECs purchased by PSNH, capacity pricing, etc., but the energy and REC pricing have the largest impact on rates.
[30] If PSNH were to purchase Class I RECs from other sources rather than pay the ACP, the cost differential would be lower, assuming that RECs could be acquired at prices below the ACP.

Environmental Issues

In addition to the current inability of PSNH's coal units to compete long-term based on fuel prices and energy price projections, environmental issues are—and will continue to be—a major source of risk for PSNH fossil plants and will have varying upward cost impacts—and, therefore, rate impacts—in terms of capital and O&M spending. This is true of the fossil-fired units only. At this time, PSNH's hydro fleet is free from any substantial, looming environmental issues. This report is not focused on whether or when such requirements may come into play. Rather the focus is to point out the existing and potential concerns and risks that are vital considerations in determining what paths to explore going forward. Below is a brief discussion of the major environmental issues on the horizon.

Water Issues

Merrimack Cooling Tower

In particular, the Merrimack plant is facing a potential major capital expense to construct a cooling tower required by the EPA to deal with reduced thermal discharge and reduced withdrawals of water from the Merrimack River.[31] This is in addition to the existing economic challenges at Merrimack. If ultimately required, the cooling tower is currently estimated to be a $111.3 million capital investment, according to the EPA. This is equivalent to a levelized cost of $10.3 million per year.[32] The draft NPDES permit also includes requirements concerning an improved fish return system (to return fish that have been impinged in the intake system safely to the river) and controls on the discharge of pollutants from the scrubber wastewater. Currently, the EPA is in the process of drafting responses to the voluminous comments received in response to the draft NPDES permit and, according to NHDES, the EPA intends to issue a final permit later in 2013.

If the requirements in the draft permit remain in the final permit, it is expected that PSNH will most likely appeal as it has stated it does not agree with the findings made by the EPA. The appeal process and, depending on the results of an appeal, construction of a cooling tower could take several years. In light of the existing market pressures for Merrimack, the cooling tower requirement poses an additional and significant risk to the economic viability of Merrimack.

Air Issues

Mercury Air Toxics

Air toxics issues represent another key challenge for PSNH coal-fired generation. Mercury Air Toxics (MATS) requirements currently have an April 16, 2015 compliance date, although there is the opportunity for a one-year extension. Merrimack will likely comply with the emissions requirements of the MATS due to the construction and operation of the new FGD scrubber. However, compliance stack testing/monitoring done in accordance with the federal requirements is necessary to determine compliance. Merrimack may also be subject to additional monitoring

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[31] September 27, 2011 United States Environmental Protection Agency (EPA), New England – Region 1, "Draft National Pollutant Discharge Elimination System Permit to Discharge to Waters of the United States Pursuant to the Clean Water Act" (NPDES Permit), available at: http://www.epa.gov/region1/npdes/merrimackstation/index.html.

[32] Both the $111.3 million capital investment and the $10.3 million levelized cost are in inflation adjusted 2010 dollars.

requirements including the installation of a new mercury monitoring system. Schiller has undergone some testing and it is uncertain at the present time what, if any, controls, operational limitations, or additional monitoring requirements will be necessary for MATS compliance.

SO_2

The new one-hour standard established by the EPA in 2010 requires states to demonstrate attainment with the new National Ambient Air Quality Standard for SO_2. As part of this demonstration, Merrimack, Schiller and Newington Stations may be required to implement additional control measures, operational restrictions and/or monitoring requirements in order for the state to reach and/or maintain attainment of the new standard. The operation of the Scrubber at Merrimack demonstrates compliance with the new standard however, additional control measures and/or restrictions may be necessary to address operation of Unit 1 in bypass mode (emissions from Unit 1 bypassing the scrubber and discharging through the old Unit 2 stack). Due to the delay in federal implementation guidance, the impacts on Schiller and Newington are uncertain at this time. Once federal guidance and/or federal regulations are complete for the implementation of this new standard, a full evaluation of compliance will be finalized in accordance with the federal requirements. Schiller and Newington may be subject to additional control measures, operational restrictions and/or monitoring requirements.

Regional Haze

Pursuant to federal CAA requirements, New Hampshire established its Regional Haze Rule, Env-A 2300[33], on January 8, 2011. The rule was approved into New Hampshire's federally required State Implemntation Plan (SIP) on Aug. 22, 2012 (77 FR 50602). Regional haze requirements have a two-and-a-half year compliance schedule with a compliance date of June 1, 2013. PSNH stated that representatives of Merrimack Station and Newington Station worked with the New Hampshire Department of Environmental Services (NHDES) to determine what controls and work practices (fuel blending, etc) would be required to meet the regional haze goals. PSNH stated that it submitted to NHDES the expected costs to comply with the rule (which were not quantified) and further stated that it anticipates no additional capital costs will be needed to comply with the rule.

RGGI

Costs to comply with the Regional Greenhouse Gas Initiative (RGGI) are included in PSNH's generation costs. PSNH currently receives an annual allocation of 1.5 million CO_2 allowance. These "bonus" allowances will go away after 2014, therefore PSNH will need to purchase the necessary allowances at market price ($3 – $4 per ton estimated range for an estimated annual cost of $4.5 – $6.0 million). PSNH noted that its earned bank of bonus allowances held by NHDES is almost 17 million,[34] and it will discuss with the legislature the opportunity to continue authorization of the granting of allowances pursuant to RSA 125-O:24.[35] Absent continued authorization for the allowances, RGGI compliance will pose an additional cost burden to PSNH's fossil generating units and its default service customers.

[33] See http://des.nh.gov/organization/commissioner/legal/rules/documents/env-a2300.pdf

[34] NHDES estimates that once the 2013 and 2014 allowances are taken into account, the number will be closer to 18 million.

[35] See RSA 125-O:24, VIII and IX: http://www.gencourt.state.nh.us/rsa/html/X/125-O/125-O-24.htm.

Alternatives in Moving Forward

When looking to future years and exploring the issues of PSNH's continued ownership and operation of its generating assets along with the related impacts to the competitive electricity market, the Commission's Mission Statement provides guidance in addressing the issues we face here:

> To ensure that customers of regulated utilities receive safe, adequate and reliable service at just and reasonable rates.
>
> To foster competition where appropriate.
>
> To provide necessary customer protection.
>
> To provide a thorough but efficient regulatory process that is fair, open and innovative.
>
> To perform our responsibilities ethically and professionally in a challenging and supportive work environment.

The circumstances require the Commission to address a number of important subjects, which are in tension with one another in certain respects:

- PSNH's default service rate and its relation to market prices
- A robust competitive electricity market
- The financial health of New Hampshire's largest utility
- Environmental concerns
- Fuel diversity

Different stakeholders have differing views of the priority of those areas of importance.

PSNH has consistently touted the benefits of its generation fleet, particularly from the perspective of fuel diversity and as a hedge against market price spikes. PSNH's generating assets, given their wide variety of fuel sources—coal, gas, wood, water—offer some limited options and hedging ability when one or more fuel sources undergo disruption. PSNH believes that the current natural gas fuel supply and price advantages are not structural. Therefore, PSNH considers it appropriate to retain its generation fleet with its current composition to provide default service to its customers. PSNH provided general New England market information concerning the region's reliance on natural gas and current gas supply constraints, but did not provide any analysis particular to its generation fleet to support a positive future outlook for the plants. PSNH's default service rate has been over-market for the last few years, and it appears that it will remain so for at least the near future. One can therefore question the wisdom of retaining the assets. The next logical step then is to explore alternative approaches with respect to PSNH's generation fleet along with the advantages and disadvantages of each approach. Among the available approaches are the following:

- Status Quo
- PSNH sells all of its plants (including entitlements)
- PSNH sells some of its plants and entitlements
- PSNH retires some plants
- PSNH transfers its plants to a new competitive affiliate

We find pros and cons associated with each of the approaches centering on factors such as timing, complexity, rate implications and the potential need for legislative changes. Sale or retirement of PSNH's generating units are governed by RSA 369-B:3-a:

> **Divestiture of PSNH Generation Assets.** – The sale of PSNH fossil and hydro generation assets shall not take place before April 30, 2006. Notwithstanding RSA 374:30, subsequent to April 30, 2006, PSNH may divest its generation assets if the commission finds that it is in the economic interest of retail customers of PSNH to do so, and provides for the cost recovery of such divestiture. Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the commission finds that it is in the public interest of retail customers of PSNH to do so, and provides for the cost recovery of such modification or retirement.

How parties interpret that statute will also play into the exploration of those alternatives.

Status Quo

By far the simplest approach from both timing and logistical perspectives—and the approach apparently preferred by PSNH— is for PSNH to continue owning and operating the plants as it currently does and use the plants to provide default service pursuant to RSA 369-B:3, IV(b)(1)(A). "Status Quo" is apparently PSNH's answer to "how PSNH proposes to maintain safe and reliable service to its default service customers at just and reasonable rates in light of those market conditions." However, as discussed earlier in this report, the current situation has in recent years resulted in above-market default service rates and an increasing rate of customer migration away from PSNH's default service rate which puts continuing and increasing upward pressure on that rate. PSNH has instituted changes to its plant operations and purchasing strategies in light of changing market conditions. Despite those changes, however, cost pressures have created a situation that appears unsustainable.

Under a status quo approach, PSNH's default service customers get the benefit of any below-market generation costs, incur the detriment of any above-market generation cost. They pay for PSNH's fixed costs associated with the facilities. The risks and rewards to the affected customers of such an approach vary widely depending on volatile fuel and energy market conditions. In the earlier years of restructuring PSNH's default service rate was below market, thereby providing a benefit to PSNH's default service customers. Over the last few years the situation has reversed and those customers who have continued to take default service from PSNH have been paying above-market rates. As shown by the results of the various rate scenarios, the current situation of above-market PSNH default service rates will likely continue even under a range of possible scenarios.

PSNH sells all of its plants (including entitlements)

As of March 31, 2013, PSNH's generating units had the following net book values:

Table 4

PSNH Generating Plant Balances as of March 31, 2013
($000)

Generating Unit	Gross Plant	Depreciable Plant	Accumulated Depreciation	Net Plant
Fuel-fired				
Merrimack Station	662,858	662,758	159,029	503,829
Newington Station	150,204	147,787	112,813	37,391
Schiller Station	214,166	213,704	130,429	83,737
Wyman No. 4	6,961	6,943	6,271	690
Combustion Turbines	10,937	10,925	10,078	859
	1,045,126	1,042,117	418,620	626,506
Hydroelectric				
Amoskeag	12,778	12,410	3,814	8,964
Ayers Island	11,997	11,650	2,296	9,701
Eastman Falls	9,368	9,098	3,711	5,657
Garvins Falls	11,717	11,638	4,862	6,855
Smith	9,283	8,870	2,915	6,368
Other Units	13,392	13,021	3,721	9,671
	68,535	66,687	21,319	47,216
Totals	1,113,661	1,108,804	439,939	673,722

For purposes of a sale, the sales proceeds would ideally cover the net book value remaining as of the time of the sale. The table above shows the total net book value of PSNH's generation fleet as of March 31, 2013 to be approximately $674 million.[36] In order for there to be no "loss" (a/k/a stranded costs) from a sale, the plants would collectively have to net at least $674 million through a sale.

PSNH also has in place the following power purchase agreements (PPAs):

[36] The totals include the full cost of the Scrubber as reported on PSNH's books. The inclusion of the Scrubber for purposes of this analysis serves solely to frame the discussion. Issues related to the prudence and cost recovery of the Scrubber will be determined by the Commission in DE 11-250.

- 15-year PPA with 24 MW wind facility in Lempster, New Hampshire
- 20-year PPA with 75 MW Burgess BioPower biomass facility in Berlin, New Hampshire

PSNH began purchasing power and RECs under the Lempster PPA in October 2008. The Burgess BioPower facility is expected to commence operations in November 2013.[37] Given the relatively small impact the PPAs have on PSNH's default service rate, we did not attempt to estimate the values of the PPAs. Their pricing terms involve a number of combined assumptions—as well as potential purchasers' views on those assumptions—including expectations of future energy and capacity market prices, Class I REC prices, wood fuel prices, etc.

Taking the $674 million net book value of the generating plants as a reference point, we turn to a calculation of estimated market values for the generating plants given current market conditions.

PSNH Asset Values

One objective of this Staff report is to provide a preliminary, indicative estimate of the market value of PSNH's generating assets. It is important to consider the following caveats to this material:

- The estimates are high level and make many simplifying assumptions, and are therefore not suitable replacement for investment or asset disposition decisions
- The estimate of the value of the hydroelectric assets was based on the review of a transaction involving a comparable set of assets, not the cash flow projections from the facilities
- The asset value estimates of the fossil-fired plants were based on a simplified discounted cash flow (DCF) approach of only the next five years of asset cash flow. This is not a suitable replacement for a detailed project finance model and market modeling
- The fleet value provided is only a preliminary indication of possible asset value for discussion purposes

Several methods are used for estimating the value of power generation assets. The most appropriate for this initiative are:

- Comparable transactions—Identification and review of recent, relevant transactions to establish a $/kW sale price that can be applied to same-type assets for comparative purposes.

- Discounted cash flow (DCF)—This is the approach used by power plant investors, but relies on production cost model runs, a detailed project finance model, detailed data, and projections. Liberty Consulting used a simplified DCF approach and simplifying assumptions to provide an indicative value of PSNH's power plants.

[37] In a response to a discovery request in DE 12-292, PSNH stated that it confirmed with the developer of the project that the targeted in-service date of the Burgess BioPower facility is November 18, 2013.

In order to derive a rough estimate of the values of PSNH's generating assets, we employed both methods. The values estimated in this report should only be considered indicative—actual values can only be determined by soliciting competitive bids from willing buyers and will vary based on market conditions at the time of a sale, bidders' expectations about future energy and fuel market prices and other bidder-specific interests and concerns.

Simplified DCF Approach

DCF is based on Free Cash Flow (FCF), an important component of which is earnings before interest, taxes, depreciation and amortization (EBITDA). It essentially represents operating income. To calculate FCF, EBITDA is then adjusted for taxes (including the tax implications of depreciation, but not depreciation itself which is a non-cash item), and capital expenditures. The resulting FCF is then discounted at a discount rate to reflect expected return on equity and the cost of debt (and the tax implications of debt financing).

In this simple case, we performed a valuation of 5 years of free cash flow due to the uncertainty of the PSNH assets beyond 5 years. It is worth noting that investors generally use a 10-20 year time frame in asset valuation studies, and that this simple assessment was designed to give a preliminary indication of value only. For each asset, or group of assets, analyzed, a weighted average cost of capital (WACC) was used to discount the cash flow. The WACC was calculated as a function of percent debt, the cost of debt, the return on equity (ROE) and income tax rate. For the purposes of this indicative analysis, the following WACC parameters[38] were used:

Debt Portion	60.00%
Debt Rate	6.75%
ROE	12.75%
WACC	**7.61%**
Tax Rate	38.00%

It is worth noting that power plant values, when based on DCF calculations, are sensitive to a number of operational, market and financing parameters, including the parameters that comprise WACC. Also, the WACC was applied to all the PSNH assets that were analyzed with the DCF approach, although we recognize that investors generally apply higher discount rates to riskier assets (peakers) and lower discount rates to less risky (baseload) assets. Due to these issues, the valuations provided based on the above WACC numbers were tested against a wide range of ROE and debt rate values, and it was shown that this particular analysis is not very sensitive to WACC changes. Since WACC is the cash flow discount rate that is compounded annually, it would play a more important role in the valuation of longer-term cash flow streams.

Merrimack

Merrimack showed significant losses of about $20 million per year of EBITDA. Poor dispatch cost relative to gas prices and very high fixed O&M drove this result. Capital is not a component of EBITDA, but is a component of free cash flow, making the picture for Merrimack even

[38] For the debt portion, debt rate, ROE and tax rate components of WACC were derived from a recent, non-public transaction and are used to develop indicative values of PSNH power plants only.

cloudier. The valuation used capital expenditures projections as provided by PSNH, but these did not account for the possibility of $111 million in capital expenditures for a cooling tower. Fixed O&M represents all operating and maintenance costs that do not vary in relationship to the output of the generating unit. These costs do not impact dispatch cost or capacity factor or the ability for a plant to compete on a marginal cost basis. They do, however, impact plant financials and asset value, and are also recovered by customers in a regulated company such as PSNH.

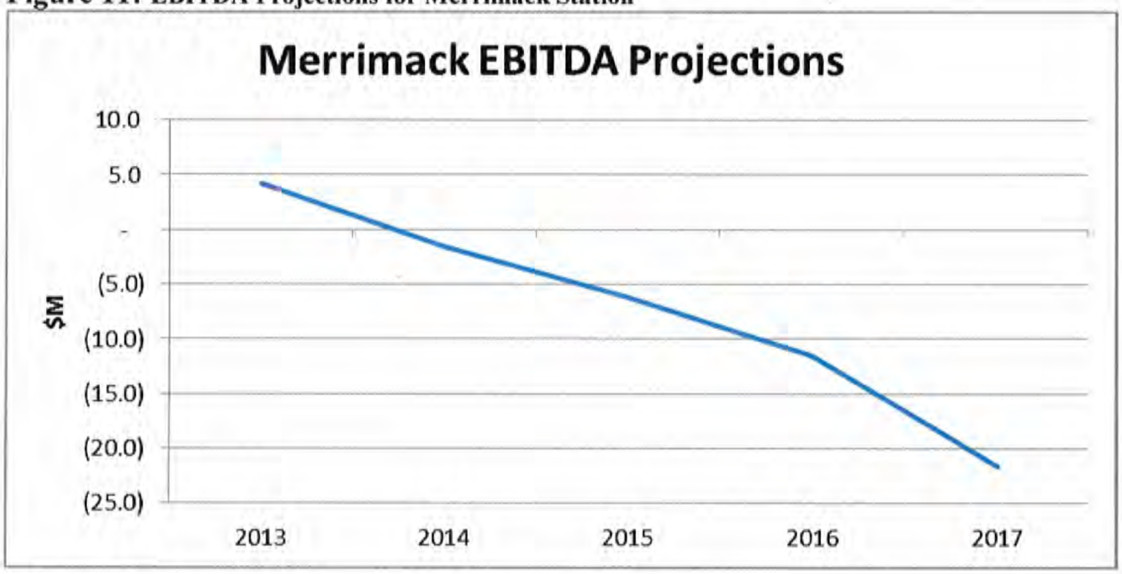
Based on the negative cash flow in each of the five years of this analysis, the value of the cash flow is negative. However, from a market standpoint, the lower limit of value is $0, which is what is estimated for the Merrimack station.

On the other hand, a coal plant in ISO-NE with declining capacity factor, Brayton Point, was recently sold for $35 per kW. For this reason, it is possible that there is also some positive value in Merrimack from sources other than the cashflow contributions from energy and capacity sales. Specifically, there may be value in the actual plant site, and that such value is likely less than or equal to the selling price of Brayton Point, which is a more competitive power plant. As such, we put an upper limit on the potential value of Merrimack at $15.4 million.

DCF valuation = $0/kW (negative value calculated)

Comparable/Site Value = $15.4 million or $35/kW

Figure 11: **EBITDA Projections for Merrimack Station**



Schiller 4 & 6

Schiller 4 & 6, collectively, show significant losses of about $8-10 million per year of EBITDA. This is driven by poor dispatch cost relative to gas prices and high fixed O&M, and does not include capital costs of $2-3 million per year (capital is not a component of EBITDA, but is a component of free cash flow). The valuation used capital expenditures projections provided by PSNH.

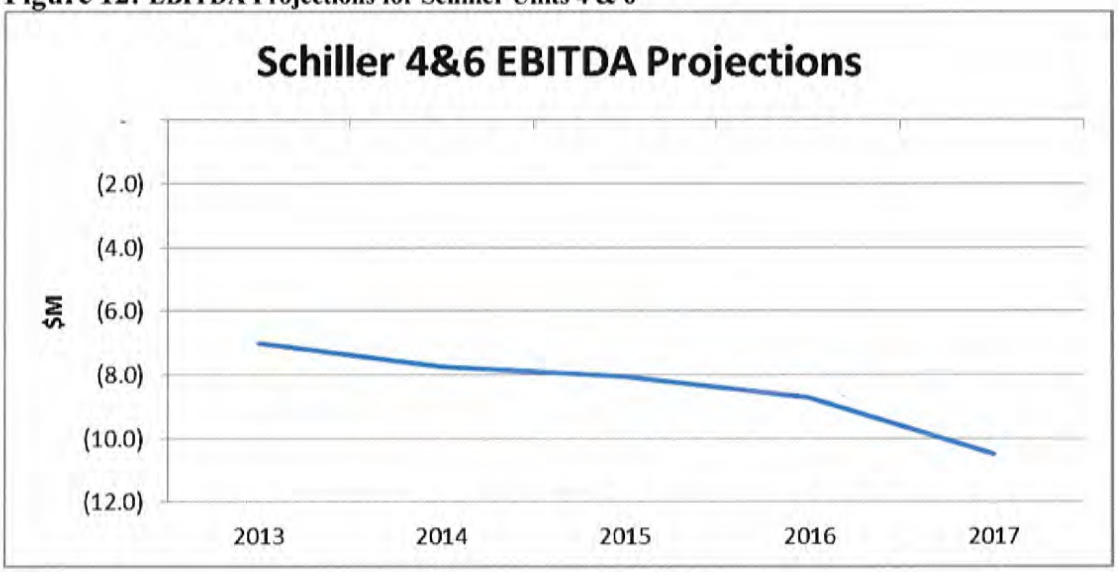
Like their counterpart, Merrimack, the Schiller coal-fired units show significantly negative EBITDA and cash flow, resulting in a DCF valuation of less than $0. Accordingly, our valuation of the cash flow from Schiller's coal-fired units for the 5-year horizon is $0.

But, like at Merrimack, it is possible that there is also some positive value in Schiller 4 and 6 from sources other than the cashflow contributions from energy and capacity sales. Specifically, there may be value in the actual plant site, and that such value is likely less than or equal to the selling price of Brayton Point, which is a more competitive power plant. As such, we put an upper limit on the potential value of Schiller 4 and 6 at $3.4 million.

DCF valuation = $0/kW (negative value calculated)

Comparable/Site Value = $3.4 million or $35/kW

Figure 12: **EBITDA Projections for Schiller Units 4 & 6**

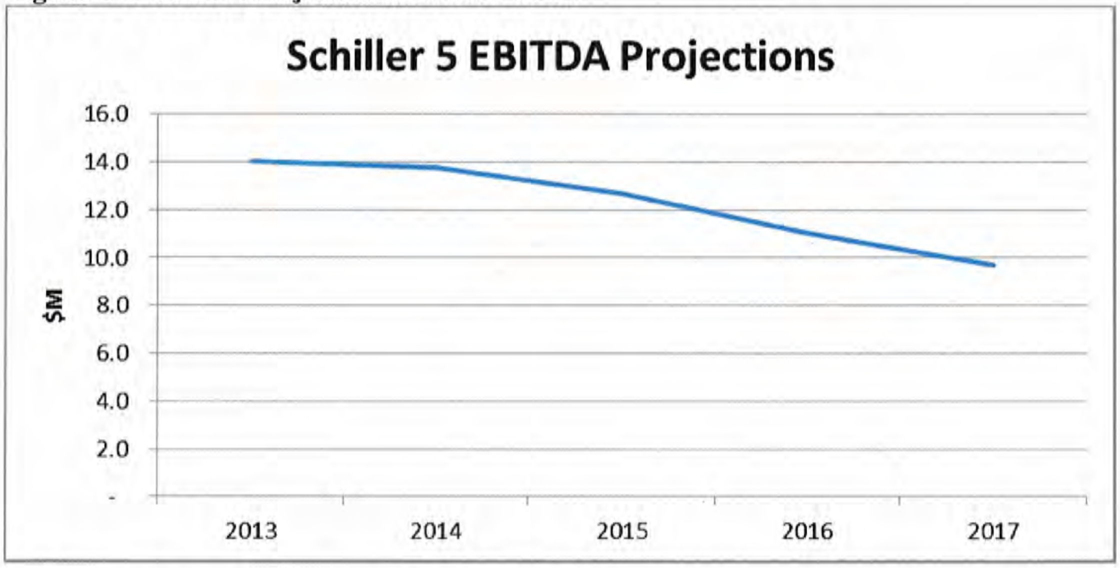


Schiller 5

Schiller 5 shows positive EBITDA from $14 million in 2013 to just under $10 million in 2017. The positive performance is largely due to the high capacity factor and the generation of both RECs and production tax credit (PTC) revenue. These are somewhat offset by high fixed O&M levels. Capital costs are $1-2 million per year (capital is not a component of EBITDA, but is a component of free cash flow), which were provided by PSNH.

DCF valuation = $34.5 million, or $803/kW

Figure 13: **EBITDA Projections for Schiller Unit 5**



Newington

For Newington, capacity factors are expected to remain low or decrease, resulting in very little energy revenue. Moreover, energy revenues at Newington will typically occur when the station is setting the market price, meaning that it will have little or no profit from energy. Accordingly, we assumed $0 net revenue for energy sales from Newington, and assumed it would generate income strictly by providing capacity for simplifying purposes.

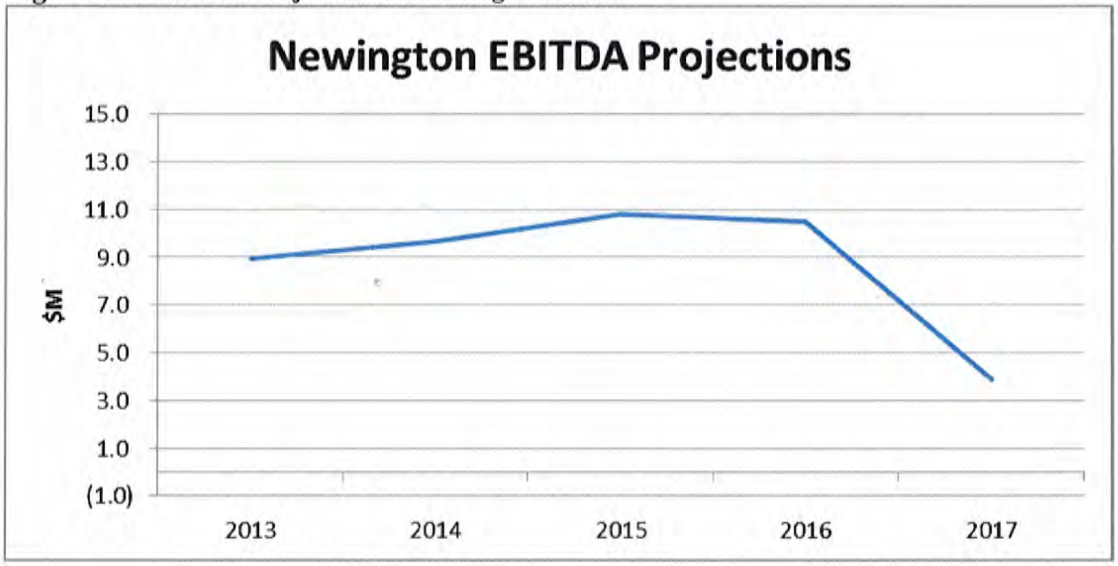
Based on the assumptions, Newington shows positive EBITDA over the next 5 years as a capacity provider, due to low fixed O&M. This results in a valuation of approximately $23 million. It is worth noting, however, that recent events indicate that the outlook for capacity-only units may be bleak.

Specifically, NRG has announced the closure of its Norwalk Harbor Station citing that "It's just too risky to stay in the market as a capacity supplier."[39] This indicates a somewhat comparable asset to Newington was determined as uneconomic by its owner, a point that should be taken into consideration when the PSNH assets are scrutinized in more detail.

DCF valuation = $23 million, or $57/kW

[39] David Gaier, NRG spokesperson, Norwalk Citizen, June 5, 2013.

Figure 14: **EBITDA Projections for Newington Station**



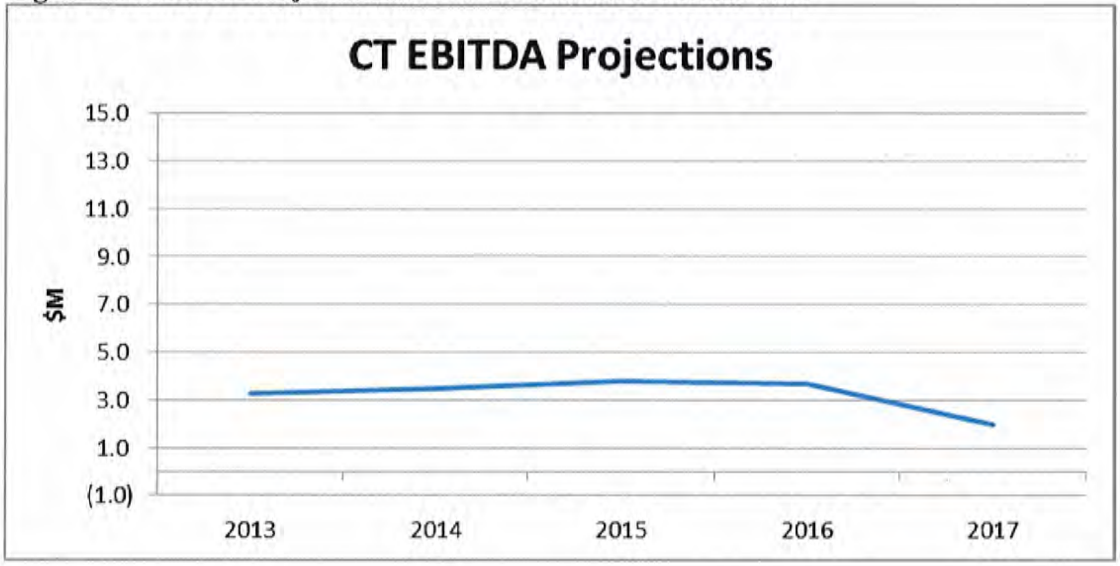
Other Peakers (Combustion Turbines)

Like Newington, which now serves in a peaking capacity, PSNH's simple cycle combustion turbines (CTs) have capacity factors that are expected to remain low, resulting in very little energy revenue. Moreover, energy revenues will typically occur when the units are setting the market price, meaning that they will have little or no profit. Accordingly, we assumed $0 net revenue for energy sales from the CTs, and assumed they would generate income strictly by providing capacity.

Based on the assumptions, the CTs show positive EBITDA over the next 5 years, due to low fixed O&M and high capacity prices, and an assumed $0 for capital additions.

DCF valuation = $9 million, or $90/kW

Figure 15: **EBITDA Projections for PSNH's Combustion Turbine Units**



Hydro Units

Intuitively and empirically, hydroelectric generating assets are at the high end of valuation of all technologies on a $ per kW basis. For this study, recent transactions for hydroelectric plants within ISO-NE have enabled the use of a comparable transactions to predict a value for PSNH hydro units. The PSNH hydro fleet was valued based on this comparable transaction and subsequent discussions with the buyer in that transaction.

In December 2012, Brookfield Power agreed to buy 19 hydro facilities (351 MW) in Maine from Nextera for $760 million, equivalent to $2,165/kW. Our information leads us to believe that the particular characteristics of the PSNH hydroelectric facilities could attract a premium on the order of 10% above those just purchased in Maine.

This assumption would make the PSNH's 70.2 MW of hydro assets worth $2,382 per kW and will be used as a proxy for the value of $167.2 million in this high level analysis.

Comparables valuation = $167.2 million, or $2,382/kW

DCF Valuation Summary

The high-level valuation approach taken in this study would produce for the PSNH generating assets a total market value on the order of $252 million, as displayed in Table 1. Again, these are based on the high-level assessment described above.

Table 5: **Summary of Estimated Asset Values for PSNH Generating Assets**

Type	MW	Basis	Value $/kW	Value $M
Coal	534.6	Cash Flow/Comps	35.00	18.7
Biomass	43.0	Cash Flow	803.41	34.5
Gas Steam	400.2	Cash Flow	56.54	22.6
Hydro	70.2	Comps	2,382.00	167.2
CT	101.5	Cash Flow	89.86	9.1
Total	1,149.5	Combined	219.42	252.2

It is worth noting that the coal unit values are based on a comparable value of $35 per kW from the Brayton Point transaction, despite the fact that the DCF approach showed negative asset value. This was done to reflect value for the site itself, which may ultimately be used to re-power to a gas combined cycle plant utilizing fuel, water and transmission infrastructure and permits.

It is also worth noting that the preliminary indications of Schiller units 4 and 6 having negative DCF value (site value notwithstanding) may offset the positive value of Schiller 5. The ability for Schiller 5 to run as a stand-alone unit was not addressed in this screening analysis.

As shown in the above Figures and Tables, the indicative values of the fleet as a whole fall well short of the net book value to the tune of approximately $420 million ($674 million net book value less $252 million indicative value).[40] On an individual basis, however, there are starkly different results depending on the fuel type and other plant characteristics. This leads to a number of questions:

- If PSNH were to offer its plants for sale, should they be packaged together, individually, or in groups?
- Should PSNH sell only some of its plants? If so, which ones?
- Should PSNH retire some of its plants?

Plant Sale Packaging Options

If a sale of PSNH generating plants were to be pursued, consideration must be given to how the sale is designed. Ideally, a sale should be designed in a way to attract the largest number of potential buyers and produce the greatest overall value. However, different buyers will have different interests based on their individual business plans and other considerations. Some buyers may only prefer one particular plant for whatever reason, but selling the plants on an individual basis could be very time consuming and costly and some plants may go unsold. Therefore, individual sales would not be a recommended course of action.

[40] We recognize that ISO-NE is pursuing options for the upcoming winter period to address the operational problems encountered during this past January and February with natural gas supplies. The proposal may provide additional short-term revenues to some PSNH generating units, however, the program has yet not been filed at FERC and it is not clear whether it would run longer than this upcoming winter period. It is also unclear what effect it would have on the economic value of the PSNH generating plants.

Another alternative would be to sell the plants in groups, e.g., the fossil plants as one group and the hydro plants as another group. Depending on the interests of potential buyers—for instance, if they currently own other fossil or hydro plants—a group sales approach could attract a diverse set of bidders if they find the grouped units to be attractive. The analysis above indicates that, the hydro plants would be expected to draw the highest values on a per kW basis and would likely result in above-book value sale proceeds. The fossil plants, on the other hand, have much lower expected per kW values and could expect to receive below-book value proceeds from a sale. Under a group sale scenario, the combination of the results of sales of the hydro and fossil plants would result in a net determination of whether there still remained net unrecovered book value, commonly referred to as "stranded costs."

The simplest alternative from an administrative perspective would be to package all of the generating plants into one sale. Such an approach would be advantageous if the purpose was to divest all units at the same time. However, bidders who may only be interested in the smaller hydro fleet may not be interested in acquiring the much larger fossil fleet for a number of reasons. If those hydro-focused bidders choose to bid on the entire fleet, their bids could very likely reflect an implicitly lower bid for the hydro units than they would have otherwise been willing to pay. Bidders interested in only the fossil fleet may find it necessary to increase their bids above what they would otherwise pay due to the inclusion of the hydro units.

In summary, in the event of a sale of PSNH's generating units, individual sale of the units would not be recommended. Selling the plants either in groups or as one total package are viable alternatives, but it would be advisable to perhaps seek additional comments or solicitations of interest.

PSNH sells some of its plants

An approach that can be viewed as a version of the group sales approach would be to sell some of the plants. There may be reasons to sell only the fossil units and retain the hydro units due to the hydro units' below-market generation cost. Conversely, some may argue that it would be beneficial to sell only the hydro plants to obtain above-book value proceeds. One drawback to a "sell some of the plants" approach, however, is that PSNH would still be in a hybrid situation, albeit to a much lesser extent. If there is an intent to effectively end the hybrid situation, then selling only some of PSNH's plants would not be a viable alternative.

PSNH retires some plants

Parties have argued in various proceedings that the fossil-fired units of Merrimack, Newington and/or Schiller Stations are prime for retirement due to economic and environmental considerations.[41] In the event of retirement, the net unrecovered book value at that time is still eligible for recovery from customers, but arguments will inevitably arise with respect to such cost recovery—an area that is discussed below. One aspect of retiring a plant, however, is that

[41] Staff notes that in recent years the following fossil-fired plants in New England have either retired, announced retirement or delisted: Salem Harbor (coal), Somerset Station (coal), Thames (coal), Mt. Tom (coal), Norwalk Harbor (oil).

the retained site of the plant may be suitable for redevelopment for a new generating facility or perhaps sold for other potential development. This report does not assess the potential site values of the various generating plants.

PSNH transfers plants to a new competitive affiliate

Given PSNH's repeatedly stated belief in the value of its overall generation portfolio, one option that could be explored is for PSNH to create a new competitive affiliate and transfer its plants to that affiliate. Currently, there is nothing in New Hampshire law that would permit the Commission to compel such an action, so any such transfer would have to be voluntary by PSNH. Alternatively, the Legislature could enact new legislation directing such a move. Under such a scenario, the competitive affiliate would operate as a merchant owner of the facilities and PSNH would then obtain default service for its default service customers in the same manner currently used by Unitil Energy Systems and Liberty Utilities. This approach can be considered a variation on a "sell the assets" approach with the difference being that the "buyer" in this case would be an affiliated company and the price at which the assets would be transferred would be governed by the Commission's administrative rules, specifically the Puc 2100 rules. The transfer of capital assets from a distribution company to an affiliate is subject to the following pricing provisions:

> *Puc 2105.09 Transfer of Goods, Services, and Capital Assets.*
>
> *(a) To the extent that these rules do not prohibit transfers between a distribution company and its affiliates, all such transfers shall be subject to the following pricing provisions:*
> *(1) A distribution company may sell, lease, or otherwise transfer to an affiliate, including a competitive affiliate, an asset, the cost of which has been reflected in the distribution company's rates for regulated service, provided that the price charged the affiliate is the higher of the net book value or market value of the asset;*
> and
> *(7) For purposes of this section, the market value of any asset sold, leased, or otherwise transferred, shall be determined based on the highest price that the asset could have reasonably realized after an open and competitive sale.*

As discussed earlier in the report, certain of PSNH's generating assets would be expected to have a market value in excess of net book value, while others would be expected to draw less than net book value if sold on the market. Taken as a whole, however, the fleet would be expected to realize an amount less than net book value through a competitive sale process. Thus, a transfer of the entire generation fleet to a competitive affiliate would most likely be achieved at net book value. A transfer of the generating assets at net book value would leave PSNH customers indifferent in that there would be no above-book or below-book asset sales revenues to manage from a rate perspective. That could be viewed as one advantage of a transfer of the assets to a competitive affiliate of PSNH. Another advantage is timing. By forgoing the need to issue an RFP to solicit bids, conduct site visits, receive and evaluate bids, negotiate sales agreements, etc., a transfer of assets to an affiliate could be achieved in a much shorter timeframe than soliciting competitive bids.

One complicating factor in such a transfer scenario is the existing power purchase agreements PSNH has with the Burgess BioPower facility in Berlin, New Hampshire and with the Lempster Wind facility in Lempster, New Hampshire. As these agreements are not fixed, depreciable assets having a specific net book value on PSNH's books, the dollar value at which they could be transferred to an affiliated company is not as clear, though sales of power purchase agreements are not uncommon in the electric industry.

Cost Recovery Issues in the Event of Sale or Retirement

Currently, cost recovery with respect to PSNH's generation facilities is governed by the following New Hampshire statutes (with the cost recovery sections italicized):

Regarding sale or retirement:

> **369-B:3-a Divestiture of PSNH Generation Assets.** – The sale of PSNH fossil and hydro generation assets shall not take place before April 30, 2006. Notwithstanding RSA 374:30, subsequent to April 30, 2006, PSNH may divest its generation assets if the commission finds that it is in the economic interest of retail customers of PSNH to do so, *and provides for the cost recovery of such divestiture.* Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the commission finds that it is in the public interest of retail customers of PSNH to do so, *and provides for the cost recovery of such modification or retirement.*

Regarding the Scrubber at Merrimack Station:

> **125-O:18 Cost Recovery.** – If the owner is a regulated utility, the owner shall be allowed to recover all prudent costs of complying with the requirements of this subdivision in a manner approved by the public utilities commission. During ownership and operation by the regulated utility, such costs shall be recovered via the utility's default service charge. In the event of divestiture of affected sources by the regulated utility, such divestiture and recovery of costs shall be governed by the provisions of RSA 369:B:3-a.

In any circumstance that involves PSNH selling or retiring some or all of its generating plant and entitlements, the strong likelihood exists that there will be a remaining amount of net book value either not covered by the sales proceeds realized or otherwise remaining to be recovered. The questions that immediately arise are:

- Who should pay those costs?
  - Customers?
  - Shareholders?
  - Some combination?
- By what method should those costs be recovered?
  - Stranded cost charge?
  - Distribution charge?
  - Some other non-bypassable charge?
  - Some other method?
- Over what period of time should those costs be recovered?
- Should there be recovery both of (depreciation) and on (return) the net unrecovered book value?
- What rate of return should be applied to the net unrecovered book value?
  - In the event of a sale
  - In the event of retirement

Rate Impacts Associated with Various Levels of Asset Values

The answers to the questions raised above are not simple nor are they expected to have unanimous answers among the various stakeholder groups. In considering those questions, an important component of this study is the possible level of default service rates over the near-term to mid-term period for those customers who remain on PSNH's default service rate, Rate ES. As described in previous sections, our analysis indicates that PSNH's default service rate will likely remain well above market and, depending on scenario, that disparity between the market price and PSNH's default service rate could become even higher than the approximately 2 cents per kWh that exists, currently. One financial mechanism associated with a potential divestiture or retirement is one used in the PSNH restructuring proceeding: securitization of stranded costs. While we do not take a position on that particular policy option in this investigation, it is one that has been used successfully in the past during electric restructuring. It is widely used in the financial industry, especially in the mortgage business, but also for non-mortgage assets such as credit card receivables and student loans.

As we note in the section titled Potential Legislative Changes, the retirement or divestiture of PSNH's generating assets and the use of securitization would need legislative changes to implement. Our purpose herein is to provide an overall rate context for PSNH default service customers based on a potential divestiture or retirement of PSNH's fossil-hydro plants under various asset values and cost recovery assumptions. The stranded cost analysis assumes that PSNH recovers all unrecovered net book value of the generation assets as stranded costs. This analysis is not meant to say that any one resulting rate scenario is more likely than another, but rather to provide context concerning rate impacts, should PSNH's default service rate result from a competitive bid process such as used by UES and GSEC, and to recognize what the combined rate impact could be as an asset sale or retirement could result in a new stranded cost charge. All assumptions used in this analysis are, therefore, illustrative and are used solely to help frame the discussion regarding cost recovery and rate impacts.

The four scenarios Staff evaluated assume that the asset sale price is either: 1) the full net book value of the fossil-hydro plants, 2) zero, 3) $100 million or 4) $300 million. Staff used the net book value of the generation plant as of March 31, 2013, $673,722,000, though we recognize that value will change if, and when, any divestiture or retirement would take place. Though sales of PPAs were common during electric restructuring, Staff did not attempt to estimate any potential market value associated with the Lempster Wind PPA or the PPA with the Burgess BioPower project. A term of 15 years was used for the recovery period of the stranded costs resulting from the net book value minus the sales price of the assets and we varied the interest rate from 2% to 6%. While the debt markets are favorable currently, the actual interest rate for any use of securitization would depend greatly on the financial markets at the time as well as the amount securitized, the size in dollars and the number of tranches to be issued, the special purpose entity or vehicle created to facilitate the transaction and numerous other important legal and structural aspects needed to guarantee a low financing rate and recovery of the cash flows.

For illustrative purposes, we used all retail load (i.e., all PSNH customers) in the denominator, 7,800,000 MWh, over which to recover any potential stranded costs. If the current load that has migrated to competitive supply was removed from the calculation, the resulting rate would essentially double, assuming 50% load migration. The stranded cost rate we calculate, averaged over a 15-year term, varies from a low of $0.00369 per kWh based on $373,722,000 of "stranded costs" ($673,722,000 net book value - $300,000,000 asset sale price) and a 2% interest rate to a high of $0.00870 per kWh if the sales proceeds for the assets was zero and the interest rate was 8%. Of course, a sale that results in full recovery would produce no stranded costs, but that outcome appears highly unlikely based on our analysis of the value of PSNH's generating units at this time.

If the plants were divested or retired, PSNH would still need to procure power for its default service load. If it did so in a manner similar to New Hampshire's other electric companies, i.e., through a competitive solicitation, we believe it would be able to procure power at similar or slightly lower rates than UES or GSEC. In today's market, that would equate to around $0.07000 to $0.07500 per kWh. These default service rate estimates combined with the stranded cost estimated rates would result in a combined rate of $0.07369 per kWh to $0.08370 per kWh. As stated above, if customer load that has migrated to competitive supply were excluded from the denominator, then the overall combined effect on default service customers would be higher as the "stranded cost" rate would be twice as high as described above. Of course, markets can and do change over time, sometimes dramatically, and these rates are provided to give some indication of outcomes that could be expected based on the assumptions used in our rate impact analysis.

The lowest and highest results of the stranded costs scenario analyses are shown in Table 6 in combination with default service rates of $0.070 cents per kWh and $0.075 cents per kWh.

Table 6

	Low Cost Scenario	High Cost Scenario
Net Book Value	$673,722,000	$673,722,000
Asset Sale	$300,000,000	$0
Potential Stranded Cost	$373,722,000	$673,722,000
Average Annual Cost	$28,811,184	$67,883,571
Stranded Cost Rate per kWh with All Retail Load of 7,800,000 MWh	0.00369	0.00870
Default Service Rate per kWh	0.07000	0.07500
Overall Combined Rate Effect per kWh	0.07369	0.08370

Some of the questions posed above could be best addressed through a collaborative process, but it is likely that such a process would be very lengthy. Even with a lengthy process involving full participation of interested stakeholders, there is no guarantee of success. Certain questions may be answered with others remaining open to dispute. What follows is a summary of views of the stakeholder groups on the areas at issue.

Stakeholder Discussions

In addition to PSNH, Staff met with a broad set of stakeholders, including representatives of power producers, competitive suppliers, and large customers. We also met with a number of environmental groups. We consulted as well with the Office of Consumer Advocate, the New Hampshire Department of Environmental Services and the Governor's Office of Energy and Planning. We found the views of the stakeholders with whom we met candid, constructive, and informative.

PSNH Asset Values

With the exception of PSNH, these representatives as a group gave little basis for confidence that the PSNH fossil units have a place in the regional marketplace. The consensus was that the units are not economic today and have no substantial likelihood of becoming so in the foreseeable future. Some identified location the plant sites as an asset and there was a general consensus that the hydro facilities have positive value that partially offsets the negative value of the fossil units.

Sustainability of Default Service at Current Rates

There was also a general consensus among stakeholders, excluding PSNH, that default service is not economically sustainable.

We addressed with stakeholders generally the question of how the high costs of default service affect the development of competition. We specifically asked whether the current large gap (over 2¢/kWh) between PSNH default service and competitive suppliers did not present an opportunity for development of more robust competition for residential and small commercial customers; *i.e.*, a strong signal of the benefits of moving to a competitive supplier. We contrasted this circumstance in PSNH's serving area with the much smaller gaps that exist in the case of the other two major state distribution companies. Acknowledging the gap's advantages, the competitive suppliers with whom we spoke still favored a prompt withdrawal of PSNH from the supply function, citing factors such as the chilling effect that an incumbent wires company can have on development of competition.

The factors commonly cited included:

- The fact that other New England coal units, some of them more efficient than those of PSNH are already being retired
- Recent sale prices of more efficient coal units produced very low values
- EPA and RGGI issues will further contribute to demise of PSNH coal
- There is a very high likelihood that shale gas will keep regional gas prices at strongly competitive prices
- Spikes that the New England region experienced this past winter likely represent a short-term phenomenon, as pipeline infrastructure is expected to expand in response to market opportunities to move gas to the region.

PSNH Units as a Hedge

Neither the wholesale generators nor the retail competitive suppliers observed significant grid reliability value to continuing operation of the PSNH fossil units. PSNH did not proffer this advantage either. PSNH, alone among the stakeholders, placed significant emphasis on the value of the fossil units as a hedge against natural gas cost spikes. The other stakeholders recognized recent conditions, but those expressing opinions about the future of natural gas markets tended to believe that transportation system constraints, rather than supply, are key, and that they are likely to be ameliorated in the near future. Moreover, general beliefs are that the costs to default customers for the "insurance" provided against gas price spikes exceed their value, and that the issue is in any event more appropriate for treatment at the regional (ISO) level.

Options for Dealing with the PSNH Generation Fleet

There was a strong consensus among stakeholders that PSNH should be out of the generation business, with some thought by government stakeholders that options for retaining the hydro facilities might prove beneficial. There was no consensus on the methods (*e.g.*, a competitive divestiture process, transfer to an affiliate, or retirement) to accomplish an exit. As noted above, however, it was clear that stakeholders consider that forcing the units to compete in the marketplace would lead to their retirement.

Establishing a level playing field (vis-à-vis PSNH as an incumbent, rate protected competitor) emerged as a major concern of the wholesale generators. They observed that a regulatory regime providing for full cost recovery raises concern about PSNH motivations in bidding its units into ISO markets. The concern is that PSNH behavior (particularly given that its plants are not often competitive in those markets) may be influenced by a belief that costs unrecovered in the markets will be recovered in retail rates for default service. They would like to see a process that requires PSNH to use competitive bidding to secure resources needed for providing default service

Stranded Costs

Whether, how and from whom stranded costs should be recovered produced no consensus. The issue can perhaps be viewed as less central to those who operate at the wholesale level. Retail suppliers expressed a general aversion to adding significant wires charges to those they would like to serve. Some expressed the view that imposing substantial stranded costs as a wires charge would cause businesses to leave New Hampshire. Some expressed strong opposition to recovery of scrubber costs by any end users other than those taking default service, others raised substantial concerns about whether such costs were prudent in the first place, and one inquired into whether a PSNH bankruptcy should be considered an option. Some did support a sharing of stranded costs among a broad range of customer groups and PSNH, including the use of cost mitigating measures, such as securitization (recognizing low interest costs prevailing in the financial markets).

The lack of consensus and the strength of opinions on the question of stranded costs make clear that resolving it will prove contentious.

Some observed that the question of stranded costs could be avoided entirely by a transfer of the fleet to PSNH at remaining book cost, observing that the idea might have appeal to PSNH, which has stressed that the units continue to have value in natural gas-constrained market conditions. This appears not to have serious potential. PSNH has not asserted that the units have value equal to or approaching book value. Moreover, those who have made this observation also believe that the units have negative value as a whole, which would make this an unappealing alternative from the outset.

Environmental Issues

The stakeholders recognized that environmental risks add to the pessimism about the future of the PSNH fossil units. The opinions about continued operations, however, largely focused on economic and not environmental consideration. The stakeholders representing environmental interests very much focused their observations on the economics of the units. They too noted that regional coal assets have either been retiring or selling for very little, which strongly evidences the market's view that the units cannot compete effectively. Some of the other points addressed by their representatives included:

- Future RGGI prices in the $5 per allowance range will generate a further direct adder to coal dispatch cost
- MATS problems at Schiller will be a major contributor to its retirement
- Natural gas prices are expected to remain low, particularly as the transportation constraints affecting New England are addressed
- The Merrimack scrubber should not be considered as providing an environmental benefit to all of New Hampshire, as opposed to a fairly small region of the state.

Potential Legislative Changes

Many existing New Hampshire statutes were written to pertain to then-existing conditions with respect to electric industry restructuring, and particularly with regard to conditions in PSNH's service territory. As market changes have taken place since those laws were enacted, attempts to apply those statutes to current conditions can be viewed in some instances as either illogical or impossible. What follows is a discussion of certain statutes that may require legislative review and modification. By no means is this an all-inclusive list. Rather the discussion serves to highlight major areas of interest.

Divestiture of PSNH Generation Assets Under RSA 369-B:3-a

Throughout the process of restructuring, the New Hampshire Legislature has proactively sought to guide the structure and timing of restructuring events as pertaining to PSNH through highly detailed statutory enactments. This role peaked in the early 2000's, both with the approval of PSNH's rate reduction bond packages, with the concurrent requirement for PSNH to divest its interest in Seabrook Station, and the Legislature's efforts at slowing down the divestiture of PSNH's fossil-fueled and hydroelectric generating assets. This effort at delaying the full impact of restructuring on PSNH's operations culminated in the passage of RSA 369-B:3-a in April 2003, in the wake of the California energy crisis. The statute specifies that, following April 30, 2006, "PSNH may divest its generation assets if the [C]ommission finds that it is in the economic interest of retail customers of PSNH to do so, and provides for the cost recovery of such divestiture." (Emphasis added). RSA 369-B:3-a further specifies that "[p]rior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the [C]ommission finds that it is in the public interest of retail customers of PSNH to do so, and provides for the cost recovery of such modification or retirement." (Emphasis added).

Given the present circumstances, the Legislature may wish to review RSA 369-B:3-a, to determine if any modifications to the statute are necessary.

Definition of Stranded Costs

In conversations regarding the future of PSNH's generation fleet, much of the discussion concerns the subject of "stranded costs." It is important to understand, then, what stranded costs are and how they are currently defined in New Hampshire law. As stated earlier, stranded costs can generally be defined as the difference between costs expected to be recovered under regulated rates and those recoverable in a competitive environment. In New Hampshire law, stranded costs are defined in RSA 374-F:2, IV as follows:

> "Stranded costs" means costs, liabilities, and investments, such as uneconomic assets, that electric utilities would reasonably expect to recover if the existing regulatory structure with retail rates for the bundled provision of electric service continued and that will not be recovered as a result of restructured industry regulation that allows retail choice of electricity suppliers, unless a specific mechanism for such cost recovery is provided. Stranded costs may only include costs of:

(a) Existing commitments or obligations incurred prior to the effective date of this chapter;

(b) Renegotiated commitments approved by the commission; and

(c) New mandated commitments approved by the commission, including any specific expenditures authorized for stranded cost recovery pursuant to any commission-approved plan to implement electric utility restructuring in the territory previously serviced by Connecticut Valley Electric Company, Inc.

The "effective date of this chapter" referred to in subsection (a) above was originally 1996, with the most recent change to the statute occurring in 2003. With respect to a potential sale or retirement of PSNH generation plants, especially considering post-statute capital additions, none of the subsections of the law as it currently exists would appear to allow for inclusion of any unrecovered net book value of the plants as stranded costs. That is an important concept because RSA 374-F:3, XII provides that stranded costs be recovered through a "nonbypassable" charge, i.e., from all customers of a utility, regardless of whether they receive default service from the utility or receive service from a competitive supplier. Given the current statutory stranded cost definition, it does not appear that any stranded costs arising from a sale or retirement of PSNH's plants would be eligible for recovery through such a nonbypassable charge, absent a legislative change, meaning that default service customers could be left with that cost burden.

Electric Rate Reduction Financing (a/k/a Securitization)

Electric industry restructuring in PSNH's service territory was accomplished through a combination of the *Agreement to Settle PSNH Restructuring* (Restructuring Settlement) considered by the Commission in Docket DE 99-099 along with the enactment of certain enabling statutes. Chapter 369-B of the New Hampshire Revised Statutes Annotated provided for the issuance of bonds with a dedicated and prioritized revenue source as a method for PSNH to recover a category of its stranded costs arising from the Restructuring Settlement.[42] The dedicated revenue source combined with the specific requirements of the bonds created an attractive investment vehicle for bond investors and allowed for lower interest rates than what would be considered "standard issue" utility bonds. These bonds have been referred to in the past as "rate reduction bonds" or "securitized bonds."

Considering the potential magnitude of stranded costs—depending on the future path taken with respect to PSNH's generation fleet—securitization may be an avenue worth pursuing. However, as the enabling legislation in Chapter 369-B dealt specifically with the particulars of DE 99-099, the statutes would need to be revised to accommodate the present day circumstances.

PSNH's Provision of Default Service

RSA 369-B:3, IV(b)(1)(A) sets forth current requirements for PSNH's provision of default service:

[42] The last of the rate reduction bonds from DE 99-099 were extinguished during the second quarter of 2013.

> From competition day until the completion of the sale of PSNH's ownership interests in fossil and hydro generation assets located in New Hampshire, PSNH shall supply all, except as modified pursuant to RSA 374-F:3, V(f), transition service and default service offered in its retail electric service territory from its generation assets and, if necessary, through supplemental power purchases in a manner approved by the commission. The price of such default service shall be PSNH's actual, prudent, and reasonable costs of providing such power, as approved by the commission.

As prescribed in the statute, PSNH must use its generation assets combined with supplemental purchases until such time as it completes the sale of its fossil and hydro assets. The Legislature may need to revisit these requirements if a sale of those assets were to take place, or if customer migration creates too much upward pressure on the default service rate.

Conclusions and Recommendations

Based on our analysis of the drivers of electricity prices in the region and the costs, both fixed and variable, associated with PSNH's generation in the near-term, and our discussions with stakeholders, Staff does not believe the status quo is a viable option going forward. Recommendations we discuss below are complex and will require the involvement of a wide range of parties. Changes resulting from the recommendations may not occur in a short timeframe, but, ultimately, they are ones that will reduce the uncertainty currently pervading numerous aspects related to New Hampshire's electricity market.

A theme that occurred throughout our meetings with stakeholders was the need for New Hampshire to complete electric restructuring. That viewpoint was expressed to us with the recognition that such a change could result in the creation of future stranded costs for PSNH customers or that it may result in less retail competition, at least in the short term. PSNH expressed its belief that their generating units provide a valuable hedge to today's volatile natural gas-driven electricity market, especially in New England. The default service rates of PSNH have been above the default service prices of New Hampshire's other electric utilities for the last 4 years and that disparity has grown to over 2 cents per kWh recently. The belief that the PSNH "physical hedge" may someday be "in the money" again as it was in the early years after electric restructuring is not supported by our analysis and PSNH provided no analysis or forecasts that would allow one to reach that conclusion. Instead, we are confronted with an ever challenging regulatory environment in which customers of New Hampshire's largest utility—predominantly residential—are faced with paying an ever increasing portion of PSNH's fixed costs as more load migrates to competitive supply and the uncertainty, in the form of potential yearly legislative proposals, concerning electric prices and policy for New Hampshire's largest electric utility.

Many important questions remain to be answered. We believe that they require prompt answers, given the circumstances. The Commission should consider opening a proceeding to receive comments and recommendations from PSNH and other stakeholders regarding this report and the issues it addresses. Particular focuses should include the following:

- Whether PSNH's default service rate remains sustainable on a going forward basis
- What "just and reasonable" means and what it requires with respect to default service in the context of competitive retail markets
- Analytically supported views of the current and expected value of PSNH's generating units under an appropriately designed range of future circumstances.
- What means exist to mitigate and address stranded cost recovery

The valuations of PSNH units as described in this report are preliminary. They indicate a lack of competitiveness across a wide range of assumptions. However, definitively assessing the costs and benefits of some options depend on reasonably firm value estimates. Securing that firmness requires more work than our report entailed. The Commission thus may also want to consider requiring an independent asset valuation process undertaken at a more detailed level.

We also recommend that consultation with legislative and executive leadership begin. We also recommend that PSNH be asked to bring forth immediately proposals that would address a transfer of energy supply assets to an affiliate in accord with the optimistic views that the company has expressed with regard to the value of those assets.