THE STATE OF NEW HAMPSHIRE
SUPREME COURT

No. ______________

**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A EVERSOURCE ENERGY**

Petition for Approval of Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery

PUC Docket No. DE 16-241

JOINT APPENDIX OF ALGONQUIN GAS TRANSMISSION, LLC and PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

APPEAL BY PETITION PURSUANT TO RSA 541:6 AND RSA 365:21
(NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION)

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STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 16-241

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

Petition for Approval of Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery

Order Dismissing Petition

O R D E R N O. 25,950

October 6, 2016

In this Order, the Commission dismisses Eversource's petition requesting approval of a contract to purchase capacity on the proposed Access Northeast gas pipeline, and associated program details and distribution rate tariff. The Commission has determined that Eversource's proposed program is inconsistent with New Hampshire law. The legal authorities relied upon by Eversource and other supporters of the petition do not overcome the policies preventing such activity found within the Electric Utility Restructuring statute, RSA Chapter 374-F.

I. EVERSOURCE'S PROPOSAL

On February 18, 2016, Public Service Company of New Hampshire d/b/a Eversource (Eversource) filed a petition for approval of a proposed 20-year contract with Algonquin Gas Transmission, LLC (Algonquin), for natural gas capacity on Algonquin's Access Northeast Pipeline Project (Access Northeast pipeline), and for recovery of associated costs through a new distribution rate tariff, to be assessed on all of Eversource's customers. In its petition, Eversource sought approval of: (1) a 20-year interstate pipeline transportation and storage contract providing natural gas capacity for use by electric generation facilities in the New England region (the Capacity Contract); (2) an Electric Reliability Service Program to set parameters for the release of capacity and the sale of LNG supply made available to electric generators through the Capacity Contract; and (3) a Long-Term Gas Transportation and Storage Contract tariff for Eversource's rates (Tariffed Rate) to be applied through a uniform cents-per-kWh rate element on all retail electric customers served by Eversource, to provide for recovery of costs associated with the Capacity Contract.

Eversource is a public utility headquartered in Manchester, operating under the laws of the State of New Hampshire as an electric distribution company (EDC). Algonquin is an owner-operator of an interstate gas pipeline located in New England. Algonquin is owned by a parent company, Spectra Energy Corp (Spectra), a publicly-traded corporation headquartered in Houston, Texas. Algonquin has partnered with Eversource's corporate parent, Eversource Energy, headquartered in Boston, Massachusetts, and Hartford, Connecticut, and with National Grid, the parent company of EDC subsidiaries in Rhode Island and Massachusetts, to develop the Access Northeast pipeline. In general terms, Eversource Energy's EDC subsidiaries in Connecticut, Massachusetts, and New Hampshire and National Grid's EDC subsidiaries in Rhode Island and Massachusetts, are each individually seeking regulatory approval of gas capacity on the Access Northeast pipeline.[1]

The Access Northeast pipeline is intended to provide 500,000 million British thermal units (MMBtu)/day of incremental gas transportation capacity and 400,000 MMBtu/day of incremental liquefied natural gas (LNG) storage deliverability. Under its petition, Eversource would hold contractual entitlements for firm gas transportation and storage deliverability up to a

[1] The Massachusetts Supreme Judicial Court issued an order prohibiting the Massachusetts Department of Public Utilities from approving the companion petition from the Massachusetts affiliates of Eversource Energy and National Grid. The Massachusetts Court concluded such a Capacity Contract would contradict the policy embodied in the Massachusetts restructuring act, which removed electric companies from the business of electric generation. 475 Mass. 191 (2016).

Maximum Daily Transportation Quantity of 66,000 MMBtu/day, which would represent 7.4 percent of the total capacity of the Access Northeast pipeline. Eversource asserts that energy cost savings resulting from the increased supply of gas capacity to New England electric generators would exceed contract-related costs by a 3:1 ratio, excluding any additional capacity-release revenues that would be credited to Eversource's customers, thereby offering Eversource's customers significant benefits and justifying the recovery of the contract costs through rates.

II. PROCEDURAL HISTORY

With its petition in February, Eversource filed supporting testimony and related exhibits along with a motion for confidential treatment of certain information. Algonquin filed a similar motion for confidential treatment on March 10, 2016. The petition and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted to the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2016/16-241.html.

There was significant interest in this docket from its inception. On February 22, 2016, the Office of Consumer Advocate (OCA) filed notice of its participation on behalf of residential ratepayers pursuant to RSA 363:28. Numerous other entities and groups sought intervenor status. They included Algonquin, NextEra Energy Resources LLC (NextEra), Richard Husband, TransCanada Pipelines (TransCanada), Portland Natural Gas Transmission System (PNGTS), Exelon Generation Company, LLC (Exelon), Coalition to Lower Energy Costs (CLEC), Tennessee Gas Pipeline Company (Tennessee), the New Hampshire Municipal Pipeline Coalition (NHMPC), SunRun Inc., Pipe Line Awareness Network of the Northeast (PLAN), Repsol Energy North America Corporation (Repsol), the Office of Energy and Planning, the Conservation Law Foundation (CLF), and ENGIE Gas &LNG, LLC (ENGIE). On April 22, 2016, the Commission issued Order No. 25,886, addressing intervention requests and certain procedural issues.

In its March 24, 2016, Order of Notice, the Commission indicated that before assessing the merits of Eversource's proposal, it would determine as a threshold matter whether the proposed Capacity Contract and the associated request for rate recovery, are consistent with New Hampshire law. The Commission set deadlines for initial submissions and responses on the legal issues of April 28 and May 12, respectively.

On May 10, 2016, the OCA filed a motion pursuant to RSA 363:32, for designation as Staff Advocates, Electric Division Assistant Director, George McCluskey and Staff Attorney, Alexander Speidel. The OCA alleged that, due to past involvement in the IR 15-124 investigation regarding gas supply constraints into the New England region, past pleadings at FERC, involvement in regional wholesale market meetings regarding related topics, and alleged statements made by Staff at a technical session in the instant docket, Messrs. McCluskey and Speidel should be designated Staff Advocates. This motion received the concurrence of CLF, Richard Husband, NextEra, and NHMPC.

III. POSITIONS OF THE PARTIES

A. Supporters of the Capacity Contract

Eversource, Algonquin, and CLEC[2] (collectively the Supporters) argue generally that Eversource's plans are authorized by a number of statutes, either standing alone or in combination. The Supporters' basic argument is that RSA Chapter 374-F, the electric utility restructuring statute, was intended to lower energy prices and that an EDC's purchase of gas capacity to be used by generators could further that intent. The Supporters argue as well that

[2] Although CLEC supported the legality of an EDC entering into a long-term gas capacity contract, it objected to the lack of a competitive procurement process for the Capacity Contract entered into by Eversource. CLEC Brief at 26-29.

Eversource's proposal could be considered to be part of its obligation to provide reliable service at reasonable rates under RSA 374:1 and :2; or the type of "least cost" resource planning required by RSA 378:37 and :38. They also point to the specific language in RSA 374:57, which sets forth an EDC's obligations when it "enters into an agreement with a term of more than one year for the purchase of generating capacity, transmission capacity or energy"; and to RSA Chapter 374-A, which discusses EDCs' participation in electric power facilities. The Supporters dispute the opposition arguments that Eversource's plan would violate the Federal Power Act and the Natural Gas Act. They maintain that the proposal is consistent with Federal law and thus not preempted.

B. Opponents of the Capacity Contract

ENGIE, NextEra, CLF, OCA, Exelon, NHMPC, and PLAN, (collectively the Opponents), all disagree. They argue that the most significant intention of the restructuring statute, RSA Ch. 374-F, was to do what its title promised and restructure the industry to get the EDCs out of the generation business completely. To the Opponents, lower rates were and continue to be expected as a result of that restructuring, as competition for generation services replaces the vertically integrated generation, transmission, and distribution structure that existed for decades before. The Opponents view competitive markets and retail choice for consumers as the key components of restructuring; rate effects are secondary to competition. They also claim that in the restructured market, the risks associated with investments in generation would be borne by the owners of that generation, not by the ratepayers of the regulated distribution utilities. As for the other statutes that are part of the Supporters' arguments, the Opponents' general position is that the restructuring statute controls. They argue that those other statutes do not support Eversource's proposal, either because they never meant what the Supporters argue, or because they have been superseded by the more recent enactment of RSA Chapter 374-F.

The Opponents make two additional points to support their position. First, they argue that the notion of an EDC charging customers for the costs of a gas capacity contract is fundamentally inconsistent with the requirement that assets included in rate base must be "used and useful." They also assert that the proposed Capacity Contract and the release of gas capacity to wholesale power generators is pre-empted by the Federal Power Act and the Natural Gas Act.[3] They cite to decisions by the Federal Energy Regulatory Commission ("FERC"), and recent decisions by the United States Supreme Court to argue that state laws permitting proposals like Eversource's improperly interfere with FERC's regulation of both the wholesale natural gas market and the wholesale electric market.

IV. COMMISSION ANALYSIS

A. New Hampshire Electric Utility Restructuring Statute, RSA Chapter 374-F

The threshold question regarding any potential proposal for gas capacity acquisition by a New Hampshire EDC is whether the Electric Utility Restructuring Statute, RSA Ch. 374-F, (Restructuring Statute) prohibits such activity. All parties to this proceeding make arguments based on the Restructuring Statute passed in 1996 and implemented over the course of many years, including most recently through Order 25,920 (July 1, 2016) approving the divestiture of Eversource's remaining hydro and fossil electric generation facilities. We must determine: (1) whether the functional separation of transmission/distribution activities on the one hand, and generation activities on the other, called for by RSA 374-F:3, III, would be violated by the terms of Eversource's proposal, and (2) if yes, whether this directive of the Restructuring Statute

[3] *See* Natural Gas Act 15 U.S.C. § 717c(b) (prohibiting preferential pricing for natural gas capacity releases) and Federal Power Act 16 U.S.C.§824(b)(1)(giving FERC core responsibility for regulating electric transmission and wholesale pricing).

overrides, or supersedes, all other restructuring principles and therefore prohibits the Capacity Contract and associated Tariffed Rate contemplated by Eversource.

In examining these questions, we apply traditional New Hampshire principles of statutory interpretation. The New Hampshire Supreme Court first looks to the language of the statute itself, and, if possible, construes that language according to its plain and ordinary meaning. The Court interprets statutes in the context of the overall regulatory scheme and not in isolation. The goal is to determine the Legislature's intent. Further, the Court construes statutes, where reasonably possible, so that they lead to reasonable results and do not contradict each other. When interpreting a statute, the Court gives effect to all words in the statute and presumes that the legislature did not enact superfluous or redundant words. *See Appeal of Old Dutch Mustard Co., Inc.,* 166 N.H. 501 (2014); *State v. Collyns*, 166 N.H. 514 (2014). When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with the subject in a specific way and the earlier enactment treats that subject in a general fashion. *Board of Selectmen v. Planning Bd.*, 118 N.H. 150, 152 (1978); *see also Appeal of Pennichuck Water Works,* 160 N.H. 18, 34 (2010) (quoting *Appeal of Plantier*, 126 N.H. 500 (1985)).

Because the Restructuring Statute contains numerous policy directives, we begin our analysis of the statute with reference to its stated purposes.

> I. The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. Increased customer choice and the development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry that will require unbundling of prices and services and at least functional separation of centralized generation services from transmission and distribution services.

> II. A transition to competitive markets for electricity is consistent with the directives of Part II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it." Competitive markets should provide electricity suppliers with incentives to operate efficiently and cleanly, open markets for new and improved technologies, provide electricity buyers and sellers with appropriate price signals, and improve public confidence in the electric utility industry.

RSA 374-F:1, I and II.

In addition to the overall statutory purposes, RSA 374-F:3 outlines the restructuring policy principles that must govern the Commission's approach to restructuring the New Hampshire electric market. RSA 374-F:3, III states, in part:

> When customer choice is introduced, services and rates should be unbundled to provide customers clear price information on the cost components of generation, transmission, distribution, and any other ancillary charges. Generation services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services which should remain regulated for the foreseeable future. However, distribution service companies should not be absolutely precluded from owning small scale distributed generation resources as part of a strategy for minimizing transmission and distribution costs.

The disagreement in this matter is based on the multiple objectives in the sections quoted above. Supporters point to the purpose of reducing costs to customers, and argue that having EDCs purchase gas capacity for use by electric generators will further that goal. Opponents argue that competition, furthered by restructuring and unbundling, is the ultimate purpose of the statutory scheme.

In weighing the restructuring policy principles of RSA 374-F, we agree with the Opponents and find that the overriding purpose of the Restructuring Statute is to introduce competition to the generation of electricity. The competitive generation market is expected to produce a more efficient industry structure and regulatory framework, by shifting the risks of generation investments away from customers of regulated EDCs toward private investors in the competitive market. The long-term results should be lower prices and a more productive economy. To achieve that purpose, RSA 374-F:3, III directs the restructuring of the industry, separating generation activities from transmission and distribution activities, and unbundling the rates associated with each of the separate services. A more efficient structure involves placing investment risk on merchant generators who can manage that risk, and allowing customers to choose suppliers, thus enabling customers to pay market prices and avoid long-term over market costs. This purpose is underscored by the Legislature's recent strong encouragement, through the passage of HB 1602 and SB 221, to approve the 2015 Settlement Agreement that will accomplish the functional separation of Eversource's generation activities from its distribution activities. *See* 2014 N.H. Laws Ch. 310 (H.B. 1602); 2015 N.H. Laws Ch. 221 (S.B. 221); and Order No. 25,920 (July 1, 2016).

Based on that finding, we conclude that the proposal brought forward by Eversource is fundamentally inconsistent with the purposes of restructuring. Specifically, we conclude that the Capacity Contract is a component of "generation services" under RSA 374-F:3, III, which requires unbundled, clear price information for the cost components of generation, transmission, and distribution. The acquisition of the gas capacity is clearly related to an effort to serve New England gas-fired electric generators with less expensive, more reliable fuel supplies. Including such a generation-related cost in distribution rates would combine an element of generation costs with distribution rates and conflict with the functional separation principal.

Having concluded that the basic premise of Eversource's proposal – having an EDC purchase long-term gas capacity to be used by electric generators – runs afoul of the Restructuring Statute's functional separation requirement, we turn to the question of whether any of the other purported justifications would allow us to go forward in this proceeding to consider the merits of the proposal. To analyze the effect of other statutes applicable to EDCs on the Restructuring Statute, we must consider two issues. First, we must identify whether any of those statutes standing alone would support the Eversource proposal, and, if so, how those statutes are affected by the subsequent enactment of the Restructuring Statute.

B. Commission's General Oversight and Other Utility Statutes

Supporters note that RSA 374:1 and RSA 374:2 require that EDCs provide safe and reliable service at just and reasonable rates. They claim that by entering into the Capacity Contract and then selling capacity to gas-fired electric generators, Eversource would both increase reliability of electric supply and mitigate price spikes in the wholesale and retail markets in New England. That would, in turn, help Eversource meet its obligations under RSA 374:1 (safe and reliable service) and RSA 374:2 (just and reasonable rates). While we agree that those two sections of our supervisory statutes govern our regulation of Eversource's provision of distribution services, we do not agree that an EDC is responsible for either the reliability of the generation supply, or the price of such supply. That function has been shifted to the competitive marketplace for retail electric generation service in New Hampshire. For regional wholesale electric markets, the responsibility for regulating reliability and pricing remains with ISO-NE and FERC. *See* Federal Power Act, 16 U.S.C. § 824 (federal jurisdiction over electric transmission and wholesale electric sales).

Supporters also claim that the least cost planning statutes, RSA 378:37 and 378:38, create an affirmative obligation for Eversource to plan for adequate energy supply resources. The Legislature has set the goals for planning as follows:

> The general court declares that it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.

RSA 378:37. In fulfilling its planning obligations a regulated utility is required to do a number of assessments, including:

> III. An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources….
>
> VI. An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.
>
> VII. An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.

RSA 378:38, III-VII. The Supporters reason that if the required assessments of generating capacity, price, and supply show that more gas is needed, and if the gas-fired generators are unwilling to purchase the necessary capacity, then it is the responsibility of the EDCs to do what has to be done and commit to those purchases.

Reading the planning statutes together with RSA Ch. 374-F, however, we do not find that the statutes permit the re-joining of distribution and generation functions in the manner provided by the Capacity Contract. The planning statutes must be read in concert with RSA Ch. 374-F and in light of the industries to which they apply. RSA 378:38 applies to both electric and natural gas utilities, and those industries now differ in a fundamental way. While natural gas utilities continue to arrange natural gas supplies for their residential and small commercial customers, following electric restructuring, electric utilities do not arrange electric supply for their customers. Instead, pursuant to RSA 374-F:3, V(c), electric utilities provide electric supply through default service, which is offered only to those customers who have not opted to purchase their electricity from a competitive supplier. Default service is designed to be a safety net for customers who do not choose an independent competitive supplier. Further, default service must be competitively procured. *Id.* As a result of the Restructuring Statute, electric distribution utilities are no longer required to conduct long-term planning for electric supply. Accordingly, we find that in a restructured electric industry, the planning requirements for an EDC are limited to procurements of electric supply for the EDC's default service customers. That obligation is not broad enough to justify approval of a proposal like Eversource's.

Supporters also point out that the 10-Year New Hampshire State Energy Strategy, referenced in RSA 378:38, VII, encourages exploration of ways to increase gas pipeline capacity in New England. They claim that the Strategy thus requires EDCs to explore ways to increase gas pipeline capacity. We disagree. As discussed above, RSA 378:38 applies to both electric and gas utilities. Both are required to plan to have an adequate supply to meet their customers' demand. In our view, gas supply under the State Energy Strategy is the responsibility of the gas utilities. While Eversource, an EDC, cannot enter into the Capacity Contract and have it paid for through its distribution rates, natural gas utilities might be appropriate proponents of increased gas pipeline supply under RSA 378:38, VII. *See Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order No. 25,822 (October 2, 2015) (approving firm transportation agreement for natural gas supply).

Supporters cite RSA 374:57, "Purchase of Capacity," as support for Eversource's proposal.

> Each electric utility which enters into an agreement with a term of more than one year for the purchase of generating capacity, transmission capacity or energy shall furnish a copy of the agreement to the [C]ommission no later than the time at which the agreement is filed with the Federal Energy Regulatory Commission pursuant to the Federal Power Act or, if no such filing is required, at the time such agreement is executed. The [C]ommission may disallow, in whole or part, any

> amounts paid by such utility under any such agreement if it finds that the utility's decision to enter into the transaction was unreasonable and not in the public interest.

RSA 374:57. The Opponents, however, maintain that the statute does not mean what the Supporters think it means. The Opponents argue that RSA 374:57 was enacted following PSNH's bankruptcy to tighten the commission's authority over contracting decisions for electric supply; a service EDCs no longer provide. According to the Opponents, a statute intended to give the commission authority to disallow unreasonable provisions in contracts with terms longer than one year cannot mean an electric utility can enter into a long-term contract for gas transmission.

While the Supporters' reading of the statute is plausible, we believe the Opponents have the better argument. The meaning of "capacity" in that legislation is limited to electric generating capacity and electric transmission capacity. First, the types of agreements listed are commonly associated with electric supply. Second, if gas capacity was to be included, the statute would have included references to the Natural Gas Act in addition to the Federal Power Act. Thus we find that RSA 374:57 concerns long-term contracts for electric supply and does not authorize EDCs to purchase gas capacity under long-term contracts.

Supporters claim that RSA Chapter 374-A's provisions granting EDCs authority to "enter into and perform contracts" related to "participation in electric power facilities" provide support for Eversource's petition. Supporters observe that those provisions were not repealed by subsequent enactments such as RSA 374-F. NextEra argues RSA 374-A applied to vertically integrated "electric utilities" as defined in 1975 by 374-A:1, IV and therefore that the provisions in RSA 374-A:2, I and II are inapplicable in a restructured market where electric utility has been redefined. RSA 374-A:1, IV defines electric utilities as "primarily engaged in the generation and sale or the purchase and sale of electricity or the transmission thereof." We believe NextEra is correct and that RSA 374-A no longer applies to an EDC like Eversource.

The change in the industry through the Restructuring Statute, first passed in 1996, effectively ended a restructured EDC's ability to participate in the generation side of the electric industry. Given the centrality of the separation of functions between distribution and generation in the Restructuring Statute, allowing an EDC to "participate in electric power facilities" under RSA 374-A in the manner proposed by Eversource would make little sense in light of RSA 374-F.

Opponents also argue, based upon RSA 378:28, that the Capacity Contract violates the used and useful requirement which is a basic component of utility ratemaking under New Hampshire law. Supporters counter that RSA 378:28 applies to rate base and because the Capacity Contract does not add to Eversource's rate base, and is instead an ongoing expense, the used and useful standard does not apply. The requirement that utility rate base be used and useful for a utility to include a return on that rate base in rates has a corollary principle governing expenses. That is, expenses must be prudent and necessary for providing the service offered by the utility. In this case, we have found that after enactment of the Restructuring Statute, EDCs should unbundle rates for distribution from rates for energy supply. Capacity Contract expenses are not needed to supply distribution services to Eversource distribution customers. The Capacity Contract is designed to support electric generation supply, and therefore expenses related to generation supply would be disallowed in distribution rates.

C. <u>Federal law</u>

As noted above, the Opponents also argued that the Capacity Contract would violate a number of federal laws, including the Natural Gas Act, the Federal Power Act, and the terms of

FERC procedures and precedent. Having determined that we cannot approve the Capacity Contract and related capacity releases under New Hampshire law, we need not reach a decision concerning federal pre-emption.

V. CONCLUSION

The proposal before us would have Eversource purchase long-term gas pipeline capacity to be used by gas-fired electric generators, and include the net costs of its purchases and sales in its electric distribution rates. That proposal, however, goes against the overriding principle of restructuring, which is to harness the power of competitive markets to reduce costs to consumers by separating unregulated generation from fully regulated distribution. It would allow Eversource to reenter the generation market for an extended period, placing the risk of that decision on its customers. We cannot approve such an arrangement under existing laws. Accordingly, we dismiss Eversource's petition.

We acknowledge that the increased dependence on natural gas-fueled generation plants within the region and the constraints on gas capacity during peak periods of demand have resulted in electric price volatility. Eversource's proposal is an interesting one, with the potential to reduce that volatility; but it is an approach that, in practice, would violate New Hampshire law following the restructuring of the electric industry. If the General Court believes EDCs should be allowed to make long-term commitments to purchase gas capacity and include the costs in distribution rates, the statutes can be amended to permit such activities.

Because that concludes this proceeding, we deny the motion to designate Staff Advocates as moot. We will address the joint motion for confidential treatment in a separate order.

Based upon the foregoing, it is hereby

ORDERED, that Eversource's instant petition is hereby DISMISSED; and it is

FURTHER ORDERED, that the information subject to Eversource's joint motion for confidential treatment should be kept confidentially, pending an order by the Commission regarding the disposition of same under RSA Chapter 91-A; and it is

FURTHER ORDERED, that the motions to designate Staff Advocates are hereby DISMISSED, having been rendered moot by the decision delineated in this Order.

By order of the Public Utilities Commission of New Hampshire this sixth day of October, 2016.

Martin P. Honigberg Chairman	Michael J. Iacopino Special Commissioner	Kathryn M. Bailey Commissioner

Attested by:

Kimberly Nolin Smith
Assistant Secretary

SERVICE LIST - EMAIL ADDRESSES- DOCKET RELATED

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**BEFORE THE NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION**

EVERSOURCE ENERGY - PETITION FOR APPROVAL OF GAS INFRASTRUCTURE CONTRACT WITH ALGONQUIN GAS TRANSMISSION, LLC	:	DOCKET NO. DE 16-241

**ALGONQUIN GAS TRANSMISSION, LLC'S
MOTION FOR REHEARING AND/OR RECONSIDERATION**

Pursuant to RSA 541:3, RSA 365:21 and Rule Puc 203.33, Algonquin Gas Transmission, LLC ("Algonquin") hereby respectfully requests that the New Hampshire Public Utilities Commission ("Commission") reconsider or conduct a rehearing of Order No. 25,950 ("Order").

BACKGROUND

On February 18, 2016, Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource") filed a petition ("Petition") with the New Hampshire Public Utilities Commission ("NH PUC" or the "Commission") for approval of a proposed 20-year contract between Eversource and Algonquin for natural gas capacity on Algonquin's Access Northeast Project (the "Access Northeast Contract"); an Electric Reliability Service Program ("ERSP") to set parameters for the release of capacity and liquefied natural gas ("LNG") to electric generators; and a Long-Term Gas Transportation and Storage Contract tariff ("LGTSC") to provide for the recovery of costs associated with the Access Northeast Contract (collectively, with the ERSP and Access Northeast Contract, the "Access Northeast Program").[1] Several parties, including Algonquin, intervened.[2]

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[1] *See, generally*, Petition.

[2] The Order discusses the two rough groupings of parties, and this Motion maintains those groupings. The "Supporters" include Eversource, Algonquin and the Coalition for Lower Energy Costs ("CLEC"). The "Opponents" include Conservation Law Foundation ("CLF"); Exelon Generation Company, LLC ("ExGen"); ENGIE Gas & LNG LLC ("ENGIE"); Office of Consumer Advocate ("OCA"); New Hampshire Municipal Pipeline Coalition ("Municipal Coalition"); NextEra Energy Resources, LLC ("NEER"); and Pipe Line Action Network for the Northeast ("PLAN"). *See* Order, at 4-5.

On March 24, 2016, the Commission issued an Order of Notice in the above-referenced matter setting forth a two-phase proceeding. In the first phase ("Phase I"), the Commission would consider whether the Access Northeast Program is allowed under New Hampshire law.[3] In the event of an affirmative decision on this issue, the Commission would then open a second phase ("Phase II") "to examine the appropriate economic, engineering, environmental, cost recovery, and other factors presented by Eversource's proposal."[4] Initial Briefs and Reply Briefs regarding Phase I issues were submitted on or about April 28, 2016 and May 12, 2016, respectively. On October 6, 2016, the Commission issued the Order on Phase I issues. In that Order, based primarily on an incorrect interpretation that the "overriding purpose" of the Restructuring Statute was that electric generation be "at least functionally separated from transmission and distribution services" (the "Functional Separation Principle"), the Commission concluded that the Access Northeast Program was not permitted under New Hampshire law and dismissed the Petition.[5]

STANDARD OF REVIEW

The Commission may grant rehearing or reconsideration for "good reason" if the moving party shows that an order is unlawful or unreasonable.[6] A successful motion must establish "good reason" by showing that there are matters that the Commission "overlooked or mistakenly conceived in the original decision,"[7] or by presenting new evidence that was "unavailable prior to the issuance of the underlying decision…"[8]

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[3] Order, at 4.
[4] *Id.*
[5] *Id.* at 15.
[6] RSA 541:3, RSA 541:4; *see also* Order No. 25,291 (Nov. 21, 2011), at 9.
[7] *Dumais v. State*, 118 N.H. 309, 311 (1978) (quotation and citations omitted).
[8] Order No. 25,088 (Apr. 2, 2010), at 14.

MOTION

For the reasons discussed herein, good cause exists for the Commission to reconsider or rehear the Order. In particular, the Commission's conclusions concerning the overall goals and relationship between the principles of the Restructuring Statute (RSA Chapter 374-F) and interpretation of other statutes in light of its reading of the Restructuring Statute, are incorrect, unlawful and unreasonable.

The Commission acknowledged in its Order "that the increased dependence on natural gas-fueled generation plants within the region and the constraints on gas capacity during peak periods of demand have resulted in electric price volatility."[9] The Commission further acknowledged that Eversource's proposal has "the potential to reduce that volatility."[10] Despite these acknowledgments and record evidence that the Access Northeast Program would lower costs, the Commission ignored the plain language and legislative history of the Restructuring Statute, which had the ***primary*** purpose:

- "to reduce costs for all consumers of electricity";[11]
- "to provide electric service at lower and more competitive rates";[12]
- "to achieve lower rates for all customer classes";[13] and
- to free "residents and businesses from exorbitantly high electric rates."[14]

The Commission instead focused on only a single one of fifteen stated Restructuring Policy Principles in finding that the Access Northeast Program is inconsistent with New Hampshire law. Even if, despite the plain language and legislative history of the Restructuring Statute to the contrary, the "overriding purpose" of the Restructuring Statute was the functional

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[9] Order, at 15.

[10] *Id.*

[11] RSA 374-F:1, I.

[12] HB 1392, sec. 129:1.

[13] House Science, Technology and Energy Committee, Public Hearing on HB 1392 (Jan. 9, 1996), at 2.

[14] *Id.* at 23; *see also* Senate Executive Departments and Administration Committee Hearing (Feb. 14, 1996), at 27 (Sen. Cohen making similar remarks).

separation of generation activities from transmission and distribution activities, the Access Northeast Program would not abrogate that separation as it would simply provide a mechanism by which natural gas capacity would be made available to the generators.

Further, if all of the Restructuring Policy Principles are considered, there is no inconsistency between the Restructuring Statute and other New Hampshire energy statutes. As a consequence, there is no basis to artificially limit an electric distribution company's ("EDC") authority to acquire "transmission capacity" under RSA 374:57 to electric transmission capacity only despite the absence of any such limitation in the language of the statute itself. Similarly, since, when all of the Restructuring Policy Principles are considered, RSA Chapter 374-A is consistent with the Restructuring Statute, there is no basis to implicitly repeal RSA Chapter 374-A's grant of authority for EDCs to "participate" in electric power generation facilities. Finally, costs associated with the Access Northeast Program should be recoverable in Eversource's rates as permissible under New Hampshire law and in furtherance of the Restructuring Policy Principles.

I. THE COMMISSION MISCONCEIVED THE OVERRIDING PURPOSE OF THE RESTRUCTURING STATUTE.

In the Order, the Commission found that "the overriding purpose of the Restructuring Statute is to introduce competition to the generation of electricity."[15] However, this directly contravenes the plain language of the Restructuring Statute, is inconsistent with its legislative history, and confuses the goals of the Restructuring Statute with the methods by which to achieve those goals.

As the Order itself recognizes, the plain language of the Restructuring Statute explicitly provides that "[t]he ***most compelling reason*** to restructure the New Hampshire electric utility

[15] Order, at 8.

industry ***is to reduce costs for all consumers*** of electricity . . . ."[16] The legislative findings of the Restructuring Statute also specifically state that "New Hampshire must aggressively pursue restructuring and increased customer choice in order to provide electric service at ***lower and more competitive rates***."[17] The legislative history of the Restructuring Statute as stated by Rep. Jeb Bradley, sponsor of HB 1392 (which became the Restructuring Statute), affirms: "[The bill's] goals are simple but profound. ***Most importantly***, it hopes to achieve ***lower rates*** for all customer classes, all residents in the state of New Hampshire. Number two: It will allow customers to choose who their supplier of electricity is."[18] Further, Senator Burton J. Cohen, expressing his support for the bill, said that "[t]he issue of ***freeing*** New Hampshire residents and businesses ***from exorbitantly high electric rates*** is the ***most important*** to our constituents from a long range."[19] As Eversource noted in the record before the Commission, the Access Northeast Program would achieve this purpose by reducing the cost of electricity in New Hampshire to the benefit of all ratepayers.[20]

Yet, the Commission found that "the overriding purpose of the Restructuring Statute is to introduce competition to the generation of electricity."[21] Both the plain language of the Restructuring Statute and its legislative history specifically provide that the most compelling and most important goal of the statute is to "reduce costs" and "lower rates." In fact, the Commission itself recognized in the Order that the "purpose" of the Restructuring Statute was to

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[16] Order, at 7-8 (emphasis added); *see also* RSA 374-F:1, I.

[17] HB 1392, sec. 129:1 (emphasis added); New Hampshire Laws 1996, 129:1, IV.

[18] House Science, Technology and Energy Committee, Public Hearing on HB 1392 (Jan. 9, 1996), at 2 (emphasis added).

[19] *Id.* at 23; *see also* Senate Executive Departments and Administration Committee Hearing (Feb. 14, 1996), at 27 (Sen. Cohen making similar remarks).

[20] Petition, at 5-6.

[21] Order, at 8.

lower prices and create a more productive economy.[22] However, the Commission confused that purpose with the method of achieving it and, as a result, incorrectly found that the Functional Separation Principle was the primary goal of the Restructuring Statute.[23] Based on this erroneous finding, the Commission then incorrectly concluded that the Access Northeast Program is inconsistent with New Hampshire law. Because the Commission has mistakenly conceived the overriding purpose of the Restructuring Act, the Commission should reconsider or conduct a rehearing of the Order.[24]

II. THE COMMISSION IGNORED FOURTEEN OUT OF FIFTEEN RESTRUCTURING PRINCIPLES.

According to the Order, the Commission weighed the restructuring policy principles at RSA 374-F ("Restructuring Policy Principles")[25] and concluded that "the overriding purpose of the Restructuring Statute is to introduce competition to the generation of electricity."[26] In support of this conclusion, the Commission stated that RSA 374-F:3, III "directs the restructuring of the industry, separating generation activities from transmission and distribution activities, and unbundling the rates associated with each of the separate services."[27] The Order does not cite or discuss any of the myriad of other Restructuring Policy Principles.

The Restructuring Statute sets forth the following fifteen (15) Restructuring Policy Principles:

1. System Reliability. "Reliable electricity service must be maintained while ensuring public health, safety, and quality of life."[28]

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[22] Order, at 9-10.
[23] *Id.* at 8-9.
[24] *Dumais*, 118 N.H. at 311.
[25] RSA 374-F:3.
[26] Order, at 8-9.
[27] *Id.* at 9.
[28] RSA 374-F:3, I.

2. Customer Choice. "Customers should be able to choose among options such as levels of service reliability, real time pricing, and generation sources, including interconnected self generation" and should "expect to be responsible for the consequences of their choices."[29]

3. Regulation and Unbundling of Services and Rates/Functional Separation Principle. Electric services and rates "should be unbundled to provide customers clear price information" and generation services should be "at least functionally separated from transmission and distribution services which should remain regulated for the foreseeable future."[30]

4. Open Access to Transmission and Distribution Facilities. Non-discriminatory open access to the electric system for wholesale and retail transactions should be promoted.[31]

5. Universal Service. Universal electric service should be provided, and default service options should be available as a "safety net" to assure universal access to electricity.[32]

6. Benefits for All Consumers. Restructuring should benefit all customer classes, without benefitting one class over another, and a public benefits charge may be used to fund public benefits.[33]

7. Full and Fair Competition. "Choice for retail customers cannot exist without a range of viable suppliers. The rules that govern market activity should apply to all buyers and sellers in a fair and consistent manner in order to ensure a fully competitive market."[34]

8. Environmental Improvement. "Continued environmental protection and long term environmental sustainability should be encouraged" through both market approaches and air pollution controls.[35]

9. Renewable Energy Resources. Development of renewable energy resources should be encouraged, and should be balanced against impact on generation prices.[36]

10. Energy Efficiency. Incentives should be provided for energy efficiency and demand-side resource conservation.[37]

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[29] RSA 374-F:3, II.
[30] RSA 374-F:3, III.
[31] RSA 374-F:3, IV.
[32] RSA 374-F:3, V.
[33] RSA 374-F:3, VI.
[34] RSA 374-F:3, VII.
[35] RSA 374-F:3, VIII.
[36] RSA 374-F:3, IX.

11. Near Term Rate Relief. Effort should be made to quickly reduce electric rates during the transition to a restructured market.[38]

12. Recovery of Stranded Costs. Recovery for stranded costs should be allowed in a manner that balances "the interests of ratepayers and utilities during and after the restructuring process."[39]

13. Regionalism. New Hampshire should work in cooperation with the other New England states.[40]

14. Administrative Processes. The Commission should adapt its administrative processes to enable market participants to quickly adapt to the changes caused by restructuring.[41]

15. Timetable. "The commission should seek to implement full customer choice among electricity suppliers in the most expeditious manner possible."[42]

While these Restructuring Principles are "intended to guide" the Commission in its implementation of electric market restructuring,[43] the Restructuring Statute does not prioritize any one of the Restructuring Policy Principles over any of the others. Had the General Court intended, as the Commission concludes, that the Functional Separation Principle take primacy, it would have said so—the Commission may not read the Restructuring Statute to include a directive that is not there.[44]

While the Restructuring Statute provides for the functional separation of the generation function and the transmission and distribution function, this principle is just one of ***fifteen (15)*** Restructuring Policy Principles articulated with equal weight by the legislature. Many if not all of the other fourteen Restructuring Policy Principles would be advanced by the Access Northeast

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[37] RSA 374-F:3, X.
[38] RSA 374-F:3, XI.
[39] RSA 374-F:3, XII.
[40] RSA 374-F:3, XIII.
[41] RSA 374-F:3, XIV.
[42] RSA 374-F:3, XV.
[43] RSA 374-F:1, III.
[44] *Appeal of Old Dutch Mustard Co., Inc.*, 166 N.H. 501, 506 (2014) (holding that a tribunal may "neither consider what the legislature or commissioner might have said nor add words that they did not see fit to include.")

Program. As numerous regulators and stakeholders have recognized, New England's increasing reliance on natural gas for electric generation, without a corresponding expansion of natural gas infrastructure, threatens reliability.[45] For instance, the Restructuring Policy Principles provide that "[r]eliable electricity service must be maintained while ensuring public health, safety, and quality of life"[46] and the Access Northeast Program would enhance reliability by providing a critical upgrade to natural gas infrastructure. By displacing wintertime use of legacy fuels, like coal and oil, and providing a backstop for intermittent renewable generation, the Access Northeast Program also furthers the goals of environmental improvement[47] and encouraging renewable energy.[48] The Access Northeast Program is a regional solution, consistent with the goal of regionalism.[49] Consequently, the Order's focus on the Functional Separation Principle, to the exclusion of all the other Restructuring Policy Principles, was incorrect, unlawful and unreasonable and should be reconsidered.

III. THE ACCESS NORTHEAST PROJECT DOES NOT CONTRAVENE THE FUNCTIONAL SEPARATION PRINCIPLE.

Even if the separation of the generation function from transmission and distribution functions were the "overriding purpose" of the Restructuring Statute (which Algonquin disputes), the Access Northeast Program would not abrogate that separation. The Access Northeast Program would simply provide a mechanism by which natural gas capacity would be

[45] *See, e.g.*, ISO-New England, Regional Electricity Outlook (March 2016) (available at: https://www.iso-ne.com/static-assets/documents/2016/03/2016_reo.pdf), at 11 ("Inadequate natural gas pipeline infrastructure is at times limiting the availability of gas-fired resources or causing them to switch to oil, which is creating reliability concerns and price volatility, and contributing to air emission increases in winter."); New Hampshire Office of Energy & Planning, New Hampshire 10-Year State Energy Strategy (September 2014) (available at: https://www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf), at 46 ("In the winter of 2013-2014, the region did not have enough [natural gas] supply for both heating and electrical generation needs. This resulted in higher prices and volatility, especially on the coldest days.").

[46] RSA 374-F:3, I.

[47] RSA 374-F:3, VIII.

[48] RSA 374-F:3, X.

[49] RSA 374-F:3, XIII.

made available. While Eversource will make additional primary firm pipeline capacity available in New England, that capacity will be auctioned by a capacity manager in an arms-length process consistent with Federal Energy Regulatory Commission ("FERC") rules on capacity release. Generators, acting in their own economic interests in a fully competitive market, will either utilize it or not as they see appropriate. Thus, the decision of whether to procure and/or use the natural gas capacity made available by Eversource will rest firmly with generators. Eversource's sole and critical role will be making primary firm natural gas capacity available—Eversource will not be providing or engaged in generation.[50] Thus, the Access Northeast Program does not run afoul of the Functional Separation Principle.

As Rep. Bradley noted in 1996, the legislature sought to encourage "full and fair competition" by which it meant "a viable range of suppliers."[51] The Access Northeast Program would maintain "a viable range of suppliers" and would not pick winners and losers between suppliers.[52] In fact, the Access Northeast Program would enhance the "viable range of suppliers" by making natural gas generators that were previously unavailable to operate when dispatched available, even on the coldest winter days, and by providing a backstop to support additional intermittent renewable generation resources. Additionally, all of the many layers of competition in the electric generation supply chain would remain: generators will still competitively secure the natural gas commodity and pipeline capacity; generators will still compete in the wholesale electric marketplace; and retail electric suppliers will still competitively procure energy and

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[50] *Cf.* Staff Legal Memorandum, at 3 ("provision of gas capacity to unaffiliated merchant generators does not violate the functional separation principle of RSA 374-F:3, III in the first instance, in that New Hampshire EDCs would not actually acquire the gas capacity for their own use, but rather, would make such capacity available for the use of merchant generators in a bilateral transaction.").

[51] House Science, Technology and Energy Committee, Public Hearing on HB 1392 (Jan. 9, 1996), at 3.

[52] This is also consistent with the Restructuring Policy Principle encouraging "full and fair competition." *See* RSA 374-F:3, XII.

compete for end-user market share. Thus, the Access Northeast Program does not contravene the Functional Separation Principle.

IV. THE ORDER VIOLATES THE CANONS OF STATUTORY CONSTRUCTION.

The Commission's conclusions regarding the other statutes discussed in the Order violated the canons of statutory construction. As such, the Commission's conclusions with respect to those other statutes are unlawful and unreasonable and should also be reconsidered. Moreover, because the Commission's analysis of the other statutes was inextricably linked to its conclusions regarding the purpose of the Restructuring Statute and whether the Access Northeast Program was consistent that statute, the Commission must also reconsider its conclusions as to the other statutes discussed in the Order.

A. The Commission's Order Impermissibly Altered The Language Of RSA 374:57.

Well-recognized canons of statutory construction provide that a tribunal such as the Commission must interpret statutes consistent with the plain meaning of the language used and without adding or subtracting words. A tribunal must "first look to the language of the statute or regulation itself, and, if possible, construe that language according to its plain and ordinary meaning."[53] A tribunal may "neither consider what the legislature or commissioner might have said nor add words that they did not see fit to include."[54] For example, in interpreting a regulation related to permitting of solid waste management facilities, the Supreme Court of New Hampshire declined to read the word "facility" in a way that included accessory structures not related to solid waste handling.[55]

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[53] *Old Dutch Mustard*, 166 N.H. at 506.
[54] *Id.*
[55] *Id.* at 508-509.

RSA 374:57 authorizes EDCs like Eversource to acquire "transmission capacity" and provides:

> Each electric utility which enters into an agreement with a term of more than one year for the purchase of generating capacity, ***transmission capacity or energy*** shall furnish a copy of the agreement to the commission no later than the time at which the agreement is filed with the Federal Energy Regulatory Commission pursuant to the Federal Power Act or, if no such filing is required, at the time such agreement is executed. The commission may disallow, in whole or part, any amounts paid by such utility under any such agreement if it finds that the utility's decision to enter into the transaction was unreasonable and not in the public interest.[56]

Contrary to the canons of statutory construction, however, the Commission concluded that "[t]he meaning of 'capacity' in that legislation is limited to electric generating capacity and electric transmission capacity…."[57] However, had the legislature intended to add the word "electric" before the phrase "transmission capacity," it would have done so. Furthermore, the fact that the legislature included "energy" within the types of contracts that EDCs are authorized to enter (with PUC approval) evidences its intent not to limit the types of contracts permissible under 374:57 to just electricity.[58] Thus, the Commission's addition of words that the legislature "did not see fit to include"[59] was incorrect, unlawful and unreasonable and should be reconsidered.

B. The Commission Improperly Repealed RSA 374-A By Implication.

In the Order, the Commission concluded that "[t]he change in the industry through the Restructuring Statute, first passed in 1996, effectively ended a restructured EDC's ability to participate in the generation side of the electric industry."[60] In doing so, the Commission

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[56] RSA 374:57 (emphasis added).

[57] Order, at 13.

[58] For example, "energy" can be used to refer to district hot water distribution systems. RSA 362:4-d. By contrast, the Restructuring Act (RSA Chapter 374-F), which restructured electric utilities in particular, used the words "electricity" and "electric" instead of "energy" unless using specific phrases that typically include the word "energy" such as "energy efficiency," "renewable energy" and the like.

[59] *Old Dutch Mustard*, 166 N.H. at 506.

[60] Order, at 14.

implicitly repealed RSA 374-A's grant of authority for EDCs to "participate" in electric generation facilities in contravention of New Hampshire precedent.

As the Commission itself recognized in the Order, "the Court construes statutes, where reasonably possible, so that they lead to reasonable results and do not contradict each other."[61] The New Hampshire Supreme Court has specifically held that

> implied repeal of former statutes is a disfavored doctrine in this State. The party arguing a repeal by implication must demonstrate it by evidence of convincing force. If ***any reasonable construction*** of the two statutes taken together can be found, this court will not find that there has been an implied repeal.[62]

The Supreme Court of the United States has also held that "[i]n the absence of some affirmative showing of an intention to repeal, the only permissible justification for a repeal by implication is when the earlier and later statutes are irreconcilable."[63] While it is true that when a conflict exists between two statutes, the later statute will control, "[w]here there is no clear intention otherwise, a specific statute will not be controlled or nullified by a general one, ***regardless of the priority of enactment***."[64]

Although RSA 374-A was passed prior to the Restructuring Statute, RSA 374-A provides EDCs with the authority to undertake specific actions while the Restructuring Act is more general. Thus, RSA 374-A controls. Moreover, in this case, the legislature itself has specifically determined what statute prevails in the event of a conflict. RSA 374-A explicitly provides that "***[n]otwithstanding any contrary provision*** of any general or special law relating to the powers

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[61] Order, at 7.

[62] *Board of Selectmen v. Planning Bd.*, 118 N.H. 150, 152-53 (1978).

[63] *Morton v. Mancari*, 417 U.S. 535, 550 (1974) (holding that the Equal Employment Opportunity Act had not implicitly repealed the statute authorizing the Bureau of Indian Affairs to afford a preference to certain Native American job applicants).

[64] *Id.* at 550-51 (emphasis added).

and authorities of domestic electric utilities or any limitation imposed by a corporate or municipal charter," domestic electric utilities have the power:

> To jointly or separately plan, finance, construct, purchase, operate, maintain, use, share costs of, own, mortgage, lease, sell, dispose of ***or otherwise participate in electric power facilities*** or portions thereof within or without the state…
>
> To enter into and perform contracts and agreements for such joint or separate planning, financing, construction, purchase, operation, maintenance, use, sharing costs of, ownership, mortgaging, leasing, sale, disposal of ***or other participation in electric power facilities***… including, without limitation, contracts and agreements for the payment of obligations imposed without regard to the operational status of a facility or facilities….[65]

Thus, Eversource's authority to enter into contracts related to electric power facilities was not nullified by and still exists "notwithstanding" the Restructuring Statute (RSA 374-F). Further, Eversource still fits the definition of "electric utility" under RSA 374-A, because it is "primarily engaged in the…transmission" of electricity.[66] As a consequence, the Commission's implicit repeal of the EDCs' authority to "participate" in electric generation facilities, and its finding that RSA 374-A is no longer applicable in a restructured market, was unlawful and unreasonable.[67]

Moreover, even if the separation of the generation function from transmission and distribution functions were the "overriding purpose" of the Restructuring Statute (which Algonquin disputes), the two statutes do not contradict each other. While the Access Northeast Program would permit Eversource to make additional transmission capacity available on a primary firm basis to generators in New England, it would not provide Eversource with any ownership or operation rights or other direct interest in electric power facilities. As noted above,

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[65] RSA 374-A:2 (emphasis added).

[66] RSA 374-A:1, IV.

[67] *Morton*, 417 U.S. at 550 (holding that repeal by implication is only justified "when the earlier and later statutes are irreconcilable.").

Eversource's sole and critical role will be making primary firm natural gas capacity available. However, generators will continue to own, operate and retain their interests in the electric power facilities. Thus, Eversource will not be participating in electric power facilities. Since, through a reasonable construction of the two statutes taken together, the two statutes are reconcilable, the Commission's implicit repeal of the EDCs' authority to "participate" in electric generation facilities was unlawful and unreasonable[68] and should be reconsidered.

V. COSTS RELATED TO ACCESS NORTHEAST SHOULD BE RECOVERABLE.

The Commission's conclusions regarding the Restructuring Statute led to its further conclusion that Eversource would not be able to recover costs related to the Access Northeast Program.[69] Because the Commission's analysis of the recoverable of these costs was inextricably linked to its conclusions regarding the purpose of the Restructuring Statute and whether the Access Northeast Program was consistent with that statute, the Commission must also reconsider its conclusions as to the recoverability of the costs related to the Access Northeast Program.

CONCLUSION

For all of the foregoing reasons, Algonquin respectfully requests that the Commission grant this motion and reconsider or conduct a rehearing of Order No. 25,950.

[68] *Morton*, 417 U.S. at 550 (holding that repeal by implication is only justified "when the earlier and later statutes are irreconcilable.").
[69] Order, at 14.

Dated: November 7, 2016

Respectfully submitted,
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CERTIFICATE OF SERVICE

I hereby certify that a copy of this Motion for Rehearing and/or Reconsideration has this day been sent via electronic mail to all persons on the service list.

Emilee Mooney Scott

Emilee Mooney Scott

Dated: November 7, 2016

THE STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A
EVERSOURCE ENERGY

Docket No. DE 16-241

Petition for Approval of Gas Infrastructure Contract with Algonquin Gas Transmission, LLC

MOTION FOR RECONSIDERATION

NOW COMES Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource") and, pursuant to Puc 203.05, Puc 203.07 and RSA chapter 541-A, hereby moves the New Hampshire Public Utilities Commission for reconsideration of Order No. 25,950 issued October 6, 2016 (the "Order") in the instant proceeding relating to a proposed contract between Eversource and Algonquin Gas Transmission LLC for capacity on the proposed Access Northeast pipeline project (the "ANE Contract").

Pursuant to RSA 541:3, the Commission may grant rehearing or reconsideration when a party states good reason for such relief. *Public Service Company of New Hampshire*, Order No. 25,361 (May 11, 2012) at 4. Good reason may be shown by identifying new evidence that could not have been presented in the underlying proceeding or by identifying specific matters that were overlooked or mistakenly conceived by the deciding tribunal. *Id.* at 4-5. A successful motion for rehearing does not merely reassert prior arguments and request a different outcome. *Id.* at 5. Eversource submits that for the reasons set out below, the Commission overlooked or mistakenly conceived important legal and policy matters in the Order and that consideration is therefore appropriate.

In the Order, the Commission concluded as a matter of law,[1] that despite "the increased dependence on natural gas-fueled generation plants within the region and the constraints on gas capacity during peak periods of demand [that] have resulted in electric price volatility" and that although Eversource's proposal has "the potential to reduce that volatility," Order at 15, the Commission is powerless to deal with the volatility in electricity prices that has become the distinguishing feature of an electricity marketplace that ISO-New England has referred to as a "precarious" and "unsustainable."[2] The Commission based its determination nearly entirely upon an unreasonably narrow interpretation of the New Hampshire Electricity Restructuring statute, RSA chapter 374-F (the "Restructuring Law"), by finding that the overriding purpose of the Restructuring Law was to remove regulated utilities from the generation business. That view of the Restructuring Law does not comport with the stated purpose of the law, ignores nearly all of the interdependent policy principles enumerated in it, and appears to undermine the broad authority the Commission has been granted relative to the implementation of the Restructuring Law. RSA 374-F:1, :3, :4. Contrary to the Commission's determination that "the overriding purpose of the Restructuring Statute is to introduce competition to the generation of electricity," Order at 8, the true "overriding purpose" is to reduce electricity rates.

This was not a case where the Commission had been called upon to divine the purpose of the Restructuring Law from vague or ambiguous pronouncements, incomplete language, or through resort to legislative history.[3] In this case, the Legislature has explicitly stated the

[1] Order at 15 ("We cannot approve such an arrangement under existing laws.")

[2] *See* September 28, 2016 Comments of Gordon Van Welie, President and CEO of ISO-New England to New England Council at the New Hampshire Institute of Politics as reported at: http://www.unionleader.com/energy/New-Englands-energy-situation-precarious-ISO-leader-says-092916.

[3] *See, e.g., Forester v. Town of Henniker*, 167 N.H. 745, 749-50 (2015) (restating the common standard that when examining the language of a statute, the New Hampshire Supreme Court ascribes plain and ordinary meaning to the words used, and unless the language is ambiguous, the Court will not examine legislative history, and it will neither consider what the legislature might have said nor add words that it did not see fit to include.).

purpose of the law and that purpose is not, as the Commission concluded, "to introduce competition to the generation of electricity." Accordingly, the Commission should reconsider the Order.

The very first sentence of the restructuring legislation enacted by the General Court in 1996 is a legislative finding that reads, "New Hampshire has the highest average electric rates in the nation and such rates are unreasonably high." 1996 N.H. Laws, 129:1, I. And, in that first finding, the General Court stated that high electric rates have "a particularly adverse impact on New Hampshire citizens." Laws 1996, 129:1. The findings of the General Court continue:

> The general court finds that:
> . . .
> II. New Hampshire's extraordinarily high electric rates disadvantage all classes of customers: industries, small businesses, and captive residential and institutional ratepayers and do not reflect an efficient industry structure. The general court further finds that these high rates are causing businesses to consider relocating or expanding out of state and are a significant impediment to economic growth and new job creation in this state.
>
> III. Restructuring of electric utilities to provide greater competition and more efficient regulation is a nationwide phenomenon and New Hampshire must aggressively pursue restructuring and increased customer choice in order to provide electric service at lower and more competitive rates.
>
> IV. Monopoly utility regulation has historically substituted as a proxy for competition in the supply of electricity but recent changes in economic, market and technological forces and national energy policy have increased competition in the electric generation industry and with the introduction of retail customer choice of electricity suppliers as provided by this chapter, market forces can now play the principal role in organizing electricity supply for all customers instead of monopoly regulation.
> . . ..

Laws 1996, 129:1. The concern the General Court intended to address is clear and emphasized repeatedly – the goal was to reduce rates – and competition was only a means to achieve that stated end.[4]

[4] The New England States Committee on Electricity has recently said essentially the same:

Significantly, nothing in the Restructuring Law forbids the state's electric utilities from owning electric supply related assets. To the contrary, in the Restructuring Law the General Court found that "market forces can now play the ***principal*** role in organizing electricity supply" – not the "exclusive" role. Laws 1996, 129:1, IV. It is inconceivable that the Legislature removed from the Commission all authority to deal with the continuing issue of high electricity prices – the very issue that was the purpose of the Restructuring Law – when it determined that market forces could play a role in organizing supply.[5]

With reference to the roles of the Commission, utilities, and competitive generators in the new marketplace, the Order found that:

> The competitive generation market is expected to produce a more efficient industry structure and regulatory framework, by shifting the risks of generation investments away from customers of regulated EDCs toward private investors in the competitive market. The long-term results should be lower prices and a more productive economy.

Order at 8-9. As noted in many places, and again recently by the President and CEO of ISO-New England, the competitive generation market has operated as supposed by the Commission, but been incented to build more gas fired generation, while, in the last few years the scarcity of pipeline capacity to serve that generation has led to higher and more volatile electric costs in the

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> Take a moment to consider the purpose of restructuring.
>
> It was never to implement markets or to seek to achieve their benefits at the expense of state energy or environmental policies or to diminish environmental quality.
>
> When generators oppose in- or out-of-market mechanisms to recognize state policies in planning and markets, from use of the DG Forecast, to the Renewable Exemption, to Clean Energy RFPs, it suggests a belief that markets are an end in themselves or paramount to state laws. They are not.

NESCOE Annual Report to the New England Governors 2015 at 18, available at: http://nescoe.com/wp-content/uploads/2016/03/2015AnnualReport_23Mar2016.pdf.

[5] To do so would mean that the Commission is without real authority to improve upon the availability of a commodity that the Commission has described as a "necessity of modern everyday life." *Re Lifeline Rates*, 66 NH PUC 166, 172 (1981).

region and has imperiled reliability.[6] Furthermore, the region requires additional natural gas infrastructure, not just to ensure reliability now, but also to fully realize the region's clean energy goals.[7] The purpose statement in RSA 374-F:1, I provides "The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment." Rejecting proposals that would support the infrastructure development the region requires will not, in the long term, result in either lower prices or a more productive economy, and imperils the region's ability to ensure reliable electric service. Because the Order runs counter to the stated purpose of the Restructuring Law, and because it will lead to the opposite of the result the General Court has expressly stated is to be promoted by the Restructuring Law, the Order should be reconsidered.

Further, the Legislature, in recognizing the nature of the task, found that it would be in the best interest of the citizens of the state of New Hampshire for the General Court, and the Executive Branch, including the Public Utilities Commission, to work together to implement restructuring over the long term. 1996 N.H. Laws, 129:1,V. To that end, in 2013 the General Court found that "Development of a state energy strategy is necessary to ensure that the state's energy policies and programs support the state's economic, environmental, and public health goals," 2013 N.H. Laws, 276:1, and enacted a law requiring the Executive Branch, through the Office of Energy and Planning, to prepare a 10-year energy strategy for the state which was to

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[6] State of the Grid: 2016 Presentation, Slide 22, available at: https://www.iso-ne.com/static-assets/documents/2016/01/20160126_presentation_2016stateofthegrid.pdf; and Comments of Gordon Van Welie, President and CEO of ISO-New England, State of the Grid: 2016 Remarks, at 7, available at: https://www.iso-ne.com/static-assets/documents/2016/01/20160126_remarks_2016stateofthegrid.pdf.

[7] Comments of Gordon Van Welie, President and CEO of ISO-New England, State of the Grid: 2016 Remarks, at 2-3, available at: https://www.iso-ne.com/static-assets/documents/2016/01/20160126_remarks_2016stateofthegrid.pdf.

include review and consideration of relevant studies and plans from ISO-New England, the Commission, legislative study committees and commissions, and others. RSA 4-E:1, I, III.

Contrary to the Restructuring Law's finding that the Commission should work with others in the Executive Branch and the General Court,[8] the Commission's determination ignores the conclusions in the State's Energy Strategy.[9] Rather than working with the General Court and others in the Executive Branch as required by the Restructuring Law to encourage additional gas pipeline capacity in the region, the Order rejects Eversource's proposal by misconstruing that very law and concluding that although the State Energy Strategy explains and demonstrates the link between constrained natural gas supplies and high and volatile electric prices, the exploration of new pipeline opportunities is to be the sole province of the gas utilities.[10] Order at 12. Even assuming that to be the case, and even further assuming that natural gas companies may, at some future point, seek some new supply that may increase pipeline capacity in the region, that capacity increase would be solely procured to serve the needs of the customers of those companies, and would have only an incidental effect on electric prices or electric reliability. Such pipeline proposals, if they come to pass, will therefore not address the very

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[8] *See* RSA 374-F:1, III (stating that the "interdependent principles are intended to guide the New Hampshire general court and the department of environmental services and other state agencies in promoting and regulating a restructured electric utility industry.")

[9] As noted at page 9 of Eversource's April 28, 2016 Initial Legal Brief, the State Energy Strategy states that strained gas capacity has resulted in high and volatile electric prices and that while New Hampshire has limited influence over natural gas transmission and pipeline expansion, the State should remain engaged in regional efforts to explore ways to encourage additional pipeline capacity in the region. The State Energy Strategy also encouraged the State to continue those coordination efforts, so as to ensure that New Hampshire's interests were represented in larger decision-making forums, while exploring other opportunities such as reducing usage through efficiency and conservation.

[10] Notably, in reaching this conclusion the Commission also dismissed any electric supply planning obligation under RSA 378:37, *et seq.* as inconsistent with the Restructuring Law. Order at 10-12. This determination appears to run counter to at least some of the planning obligations described in RSA 378:38 and to differ from the opinion of the Governor, as set out in her April 13, 2016 letter to the Commission filed in this docket. Eversource questions whether the Order has, at least by implication, permanently waived those requirements. *See* RSA 378:38-a. A permanent waiver would appear to be effectively the same as implied repeal, discussed further below.

problem that the Commission, the Legislature, and others in the Executive Branch have all identified.

Further, and as Eversource pointed out in its reply memorandum at pages 9-10, competition among generators has not driven new investments that will alleviate the pipeline capacity constraints that have led to high and volatile prices. This market failure stems from the fact that the generators who might be able to make the needed investments are actually incented to prevent them to both avoid the cost and burden of supporting the necessary infrastructure, and to avoid the impact of a more abundant and reliable gas supply on their operating revenue. Rather than lowering costs for customers, the existing form of competition has served only to protect the generators' financial interests and leave electric customers in a precarious condition. In such a situation, the Commission not only has the opportunity, but arguably the duty, to assist in measures, such as the ANE Contract, that would remedy that failure and thus provide a viable path to more reliable electric generation at significantly lower prices for New Hampshire electric customers – the very goals sought by the Restructuring Law.

In the Order the Commission focused on competition; accordingly, matters pertaining to competition under the Restructuring Law were all that it saw. The conclusion relating to the Restructuring Law, and the conclusions that flowed from it, ignore the true purpose of the Restructuring Law and the interdependent policy principles therein. As that conclusion permeates the analysis and conclusions in the remainder of the Order, the Order should be reconsidered in light of the true purpose of the Restructuring Law, the clear legislative intent, the interdependent policy principles, the State Energy Strategy, and the needs of New Hampshire electric customers.

Furthermore, and as evidence of the impact of the Commission's conclusion on the remainder of the Order, in the Order the Commission noted that while supporters of the ANE Contract argued that RSA chapter 374-A provided support for the contract, it found that RSA 374-A does not apply to entities like Eversource following restructuring. In this case, the Commission's conclusion ignores the plain language of RSA 374-A, and impliedly repeals portions of RSA 374-A, and it should be reconsidered.

While Eversource had not taken the position that RSA chapter 374-A directly supports the proposed contract, other participants in the docket had. For its part, Eversource had contended that the purposes, policies and intentions of RSA chapter 374-A are served through the ANE Contract. Regardless, the Order dismisses all such contentions.

In the Order the Commission quoted the law as follows "RSA 374-A:1, IV defines electric utilities as 'primarily engaged in the generation and sale ***or the purchase and sale of electricity or the transmission thereof***.'" Order at 13-14 (emphasis added). Yet, the Commission then concluded that regardless of the plain meaning of the words in this definition, "RSA 374-A no longer applies to an EDC like Eversource." *Id.* at 14. RSA 374-A:1, IV, however, pertains to companies that generate and sell electric power, ***or that purchase and sell electric power, or that transmit electric power***. Irrespective of what is contained in the Restructuring Law, and even following Eversource's divestiture of its generating facilities, it will continue to be in the business of transmitting and selling electric power. On numerous occasions, this Commission has noted that the language of a statute must be construed according to its plain and ordinary meaning. *See, e.g., New Hampshire Elec. Coop., Inc.*, Order No. 25,426 (October 19, 2012); *Re Investigation of PSNH's Installation of Scrubber Tech. at Merrimack Station*, Order No. 24,898 (September 19, 2008); *Freedom Ring Commc'ns, LLC d/b/a Bayring*

Commc'ns, Order No. 24,837 (March 21, 2008). Indeed, in the instant Order itself, at 7, the Commission stated this traditional New Hampshire principle of statutory interpretation.

There is no doubt that Eversource is "an electric utility...primarily engaged in...the purchase and sale of electricity, or the transmission thereof." RSA 374-A:1, IV. Eversource falls precisely within the definitions of "electric utility" and "domestic electric utility" set forth in RSA 374-A:1, IV and II, respectively. Thus, RSA chapter 374-A still applies to entities such as Eversource, regardless of restructuring.

Additionally, in the Order the Commission stated:

> The change in the industry through the Restructuring Statute, first passed in 1996, effectively ended a restructured EDC's ability to participate in the generation side of the electric industry. Given the centrality of the separation of functions between distribution and generation in the Restructuring Statute, allowing an EDC to "participate in electric power facilities" under RSA 374-A in the manner proposed by Eversource would make little sense in light of RSA 374-F.

Order No. 25,950 at 14. By concluding that an EDC such as Eversource is precluded from undertaking the very activities authorized by RSA chapter 374-A, the Commission has decided that RSA chapter 374-A has been impliedly repealed by the passage of the Restructuring Law. As noted previously, such a result is one the New Hampshire Supreme Court strongly disfavors.[11]

[11] As noted in Eversource's initial legal brief at footnote 11 on page 14, in New Hampshire:

> Repeal by implication occurs when the natural weight of all competent evidence demonstrates that the purpose of a new statute was to supersede a former statute, but the legislature nonetheless failed to expressly repeal the former statute. Because repeal by implication is disfavored, if any reasonable construction of the two statutes taken together can be found, we will not hold that the former statute has been impliedly repealed.

In the Matter of Regan & Regan, 164 N.H. 1, 7 (2012) (internal brackets, quotations and citations omitted). The permissive language of RSA 374-F stating that generation and distribution services "should" be separated and that distribution services "should" remain regulated falls short of demonstrating that the laws cannot be read in harmony or the weight of all evidence shows that RSA chapter 374-A has been repealed by implication. Further, and as noted in this motion, RSA chapter 374-A applies "notwithstanding" any other law. Thus, there is a reasonable construction of the laws that avoids repeal by implication – to the extent there may be any conflict, RSA chapter 374-A continues in force.

The underlying purpose of statutory construction is to determine the intent of the legislature. In this case, the Legislature itself has determined what statute prevails in the event of a potential conflict. RSA 374-A:2 explicitly provides that "Notwithstanding any contrary provision of any general or special law relating to the powers and authorities of domestic electric utilities or any limitation imposed by a corporate or municipal charter" a domestic electric utility, such as Eversource, "shall have" certain powers and authority.[12] To the extent that RSA chapter 374-A grants certain authority to electric utilities such as Eversource to participate in electric power facilities, that authority exists notwithstanding any other general or special law, including the Restructuring Law.

Additionally, even if the doctrine of implied repeal was properly considered, if "any reasonable construction of the two statutes taken together can be found" then implied repeal is not operative. *Board of Selectmen of Town of Merrimack v. Planning Board of Town of Merrimack*, 118 N.H. 150, 153 (1978). It applies "only if the conflict between the two enactments is irreconcilable." *Gazzola v. Clements*, 120 N.H. 25, 28 (1980). Eversource submits that the Commission's determination that the Restructuring Law "trumps" other laws, including RSA chapter 374-A (and, for that matter, the "New Hampshire Energy Policy" statutes at RSA 378:37, *et seq.* as described in footnote 10, *supra*), was incorrect. There is a way to reasonably construe these statutes harmoniously and there is not an unconscionable conflict between these statutes. It is only the Commission's erroneous interpretation of the Restructuring Law that creates the conflict in the first place.

[12] "In this jurisdiction, the words of a statute are interpreted according to their plain and ordinary meaning. RSA 21:2. The plain meaning of the word 'notwithstanding' is 'without prevention or obstruction from or by' or 'in spite of.' WEBSTER'S THIRD NEW INTERNATIONAL DICTIONARY 1545 (1961)." *King v. Sununu*, 126 N.H. 302, 306 (1985). *See also In re Cote*, 144 N.H. 126, 129 (1999). Similarly, in general, the use of the word "shall" in a statutory provision is a command, requiring mandatory enforcement. *Franklin v. Town of Newport*, 151 N.H. 508, 510 (2004); *Schiavi v. City of Rochester*, 152 N.H. 487, 489–90 (2005).

For example, the Commission has previously indicated in construing a statute it was proper to determine whether a law "expressly prescribes" or "expressly proscribes" a result. *Public Service Company of New Hampshire*, Order No. 25,305 (December 20, 2011) at 28. In that proceeding, the Commission found ways to harmonize the requirements of the Restructuring Law with myriad other statutes, including the Limited Electrical Energy Producers Act at RSA chapter 362-A; the Renewable Portfolio Standard at RSA chapter 362-F; and New Hampshire's Energy Policy at RSA 378:37, *et seq.* – a law which the Commission now rejects in part as incompatible with the Restructuring Law. Order at 10-12. In this case, nothing in the Restructuring Law "expressly prescribes" or "expressly proscribes" a utility from participating in a project that would lower electric rates for its customers. The Order is in error in its interpretation of the Restructuring Law.

The Order expressly found that RSA chapter 374-A "no longer applies to an EDC like Eversource" because it "would make little sense in light of RSA 374-F." Order at 14. Whether, as a policy, keeping both statutes "makes little sense" is not a matter within the Commission's authority, nor is it a relevant factor in determining whether the powers and authority under RSA chapter 374-A remain. Nowhere does the Restructuring Law "expressly prescribe" or "expressly proscribe" a utility from owning gas pipeline capacity that would assist in reducing high and volatile electric rates where the competitive market have failed to provide such a solution. In fact, as noted earlier, the Restructuring Law states that "market forces can now play the ***principal*** role in organizing electricity supply" – <u>not</u> the "only" role. 1996 N.H. Laws, 129:1, IV.

As noted at page 9 of Eversource's reply brief, approving Eversource's proposal would enhance the ability of market forces to provide reliable, economic electricity to Eversource's customers – it would not in any way supplant the "principal role" that the region's competitive generators play in providing the supply of electric energy. Had the General Court intended market forces to play the "only" or "sole" role in providing electricity supply, it could have, and presumable would have, said so.[13] Indeed, the Restructuring Law itself gives the Commission discretion regarding this significant matter: "The commission is authorized to require that distribution and electricity supply services be provided by separate affiliates." RSA 374-F:4, VIII. Notably, by this provision of the Restructuring Law, the Legislature did not prohibit utilities from providing electric supply, but gave the Commission the authority to determine how electricity supply services from a utility may be provided.

In light of the above, and particularly in light of the clearly expressed purpose of the Restucturing Law to reduce the state's high cost of electricity, the Commission should reconsider Order No. 25,950. The Commission's conclusions in the underlying Order leading to its determination that it is barred from consideraing Eversource's project as a matter of law run counter to the purposes of the Restructuring Law and will only help to perpetuate the high and volatile electric prices in New Hampshire and New England and will continue the situation that currently imperils the reliability of the regional grid – both of which are results that the Restructuring Law was enacted to avoid.

[13] *Re New Hampshire Yankee Elec. Corp.*, 70 NH PUC 563 (June 27, 1985) (If the Legislature had intended to limit applicants to buyers, it would have so specified.); *Pub. Serv. Co. of New Hampshire*, Order No. 25,506, Docket No. DE 11-250 (2013) (if the Legislature had intended this result, it would have been easy to say so); *Northern Pass Transmission LLC /Pub. Serv. Co. of New Hampshire d/b/a Eversource Energy*, Order No. 25,910, Docket Nos. DE 15-460, -461, -462, -463 (2016) (if the legislature had intended to exclude such merchant or elective projects from licensing crossings over public lands and waters, it could have done so).

WHEREFORE, Eversource respectfully requests that the Commission:

A. Grant this Motion to Reconsider; and

B. Order such further relief as may be just and reasonable.

Respectfully submitted this 7th day of November, 2016.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

By: ______________________

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CERTIFICATE OF SERVICE

I hereby certify that, on the date written below, I caused the attached to be served pursuant to N.H. Code Admin. Rule Puc 203.11.

November 7, 2016
Date

Matthew J. Fossum

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 16-241

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

Petition for Approval of Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery

RESPONSE OF THE COALITION TO LOWER ENERGY COSTS TO ALGONQUIN AND EVERSOURCE MOTIONS FOR RECONSIDERATION

The Coalition to Lower Energy Costs ("CLEC") files this Response to the Motion for Rehearing and/or Reconsideration of Algonquin Gas Transmission, LLC ("AGT") and the Motion for Reconsideration of Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource"), each filed on November 7, 2016. This response is filed pursuant to Rule PUC 203.07(f). Both AGT and Eversource argue that Order No. 25,950 (the "Order") improperly interprets the Restructuring Statute, RSA Chapter 374-F, as restricting the ability of New Hampshire's electric distribution companies to enter into contracts that reserve long term capacity on interstate natural gas pipelines and to recover the cost of such contracts from their customers. CLEC agrees with the arguments presented by AGT and Eversource, and offers the following arguments in support of the motions.

I. The Eversource Proposal Does Not Violate the Restructuring Act.

In the Order, the Commission denied the Eversource proposal to enter a long term commitment for interstate gas pipeline capacity because doing would go "against the overriding principle of restructuring, which is to harness the power of competitive markets to reduce costs to consumers by separating unregulated generation from fully regulated distribution" and that "it would allow Eversource to reenter the generation market for an extended period, placing the risk of that decision on its customers." These conclusions are flawed, and are not based on facts such as would be adduced in hearings as to why such pipeline investment is necessary and how its absence actually impairs competitive generation markets.

CLEC agrees that the Restructuring Act emphasizes the application of *competitive* markets to achieve lower costs for customers. RSA 374-F:1(I). However, the situation that New Hampshire faces is one in which the markets on which it relies are not competitive and, in fact, are in a state of market failure. The solution presented by Eversource in its proposal would return the market to the competitive state that the New Hampshire General Court intended and assumed would be available to New Hampshire's citizens.

The Commission is well aware the electric generation industry is not one that operates naturally as a competitive market, unlike many other commodity markets. Without extensive government intervention, a competitive market for electric generation service cannot even exist at either the wholesale or retail level. The creation of ISO New England and other regional transmission organizations required Congressional action and years of development and continuing federal regulatory oversight. Indeed, the market rules of ISO New England are constantly being reviewed and revised subject to FERC approval to ensure and preserve the market's open and competitive nature. It is critical to keep in mind that *government created* this market. It would be incorrect and naive to assume that it operates perfectly without any need for monitoring and, when necessary, intervention to correct its deficiencies.

Further, markets are not ends in themselves. Rather, as the Restructuring Act itself recognizes, they are a means to an end – lower costs for consumers. RSA 374-F:3(XI) ("[t]he goal of restructuring is to create competitive markets that are expected to produce lower prices for all customers.") When market failure occurs, reliance on markets can, and this case does, lead to higher prices for consumers. This is directly contrary to the intent of the Restructuring Act.

Market failure exists because the current wholesale market structure provides no mechanism to provide for recovery of the cost of infrastructure necessary to ensure the availability of fuel supply to the generators producing most of the electric energy consumed in New England. This has created substantial price volatility and has cost New Hampshire energy consumers hundreds of millions of dollars over the past four years alone. In addition, it has threatened the reliability of the electric grid and increased New Hampshire's reliance on heavily polluting oil and coal fired generation, both also in contravention of the explicit intent of the Restructuring Act. RSA 374-F:3(I) and (VIII).

The Eversource proposal does not put Eversource in the generation business. Eversource would not own any generating units and would not contract for the purchase or sale of their output. Eversource would not benefit in any manner from changes in wholesale electric prices. Eversource would act solely as a financing conduit for its customers, flowing through all of the costs and benefits of its contractual commitment. Further, doing so would not increase the risk faced by customers; it would reduce risk. In fact, as testimony by Competitive Energy Services in Docket IR 15-124,[1] the proceeding that led to this proceeding, irrefutably showed, increased gas pipeline capacity would take away the existing risk to New Hampshire electricity consumers that they will suffer a repeat of the more than $200 million in higher electricity costs suffered in

[1] *Re Electric Distribution Utilities, Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire*, Docket IR 15-124, Direct Testimony and Exhibits of Richard Silkman and Mark Isaacson (June 2, 2015).

2013-14 because of inadequate pipeline capacity. Today customers continue to face wild volatility in prices because of the market failure. The Eversource proposal would help resolve that failure. This and related evidence should have been taken in this proceeding to give real life to the legal issues the Commission is asked to consider.

II. The Restructuring Act Must be Read in a Manner Consistent with Other Provisions of Law.

The Commission itself specifically recognized in the Order, "the Court construes statutes, where reasonably possible, so that they lead to reasonable results and do not contradict each other."[2] The New Hampshire Supreme Court has specifically held that

> [I]mplied repeal of former statutes is a disfavored doctrine in this State. The party arguing a repeal by implication must demonstrate it by evidence of convincing force. If any reasonable construction of the two statutes taken together can be found, this court will not find that there has been an implied repeal.[3]

Similarly, the Supreme Court of the United States has held that "[i]n the absence of some affirmative showing of an intention to repeal, the only permissible justification for a repeal by implication is when the earlier and later statutes are irreconcilable."[4] Therefore, under the well-established principles of "implied repeal," it would be improper to find that the Restructuring Act implicitly prohibits such a transaction if it is permitted by other provisions of law. The very opposite of irreconcilability is demonstrated by New Hampshire law.

Eversource is a corporation founded under the general corporation statutes of New Hampshire. The powers of corporations under New Hampshire law are laid out in exceedingly broad terms in RSA Chapter 295. Section 295:2 states:

> The rights, powers and duties set forth in this chapter are incident to all corporations legally constituted not excepted in RSA 295:1, subject to any limitations or restrictions

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[2] Order at 7.
[3] *Board of Selectmen v. Planning Board*, 118 N.H. 150, 152-53 (1978).
[4] *Morton v. Mancari*, 417 U.S. 535, 550 (1974)

imposed by their charters or articles of association or the laws under which they were organized.

Section 295:6 provides that corporations:

> may make contracts necessary and proper for the transaction of their authorized business, and no other. They shall be capable of binding themselves as sureties or guarantors for others, to the extent that such suretyship or guarantee may be necessary and proper for the transaction of their authorized business or serves to further their corporate purposes.

These broad statutory provisions authorize Eversource to engage in any lawful activity absent a specific legal limitation or restriction. Broad authority is not an accidental feature of the statutory scheme or a symptom of legislative inattention; it is the basic underpinning of the free enterprise guaranteed by the New Hampshire Constitution. In the case of corporations affected with the public interest, like Eversource, there are specific statutory restrictions (e.g., pre-approval requirements) placed on certain corporate actions, but these are explicit exceptions to the otherwise plenary discretion to take any lawful action the corporation deems "necessary and proper."

Nothing in Eversource's history, corporate documentation, or the laws under which it was organized imposes any limitation or restriction on Eversource's "necessary and proper" authority to enter into contracts for pipeline capacity. Public Service Company of New Hampshire ("PSNH"), d/b/a Eversource, was originally incorporated on August 16, 1926 "under the provisions of Chapter 225 of the Public Laws of the State of New Hampshire known as the Business Corporation Law.[5] At that time, the "objects" of the corporation included:

> "To acquire by construction, purchase or otherwise, and to maintain and operate any plant or property for the production, sale and distribution of electrical energy, gas, ice, water, heat or light, and to acquire by construction, purchase or otherwise, and/or to maintain and operate any other property or business, and specifically, but without limiting the generality of the foregoing, to acquire, use and enjoy the properties, rights

[5] State of New Hampshire, Record of Organization of Public Service Company of New Hampshire, *Articles of Agreement of Public Service Company of New Hampshire* (1926).

> and franchises of existing public utilities, and to carry on the business purpose of a public utility in the State of New Hampshire and/or elsewhere[;]"[6]
>
> "To acquire in any lawful manner, to own and/or hold ...property both real and personal, of any kind[;]"[7] and
>
> "To enter into, make, perform and carry out contracts of any kind for any lawful purpose without limit as to amount, with any person, firm, association, corporation, municipality, county, state, territory or government...[.]"[8]

The most recently recorded Amended Articles of Incorporation of PSNH set forth "Corporate Powers" as follows:

> The objects for which this corporation is established are to carry on the business of any electric utility within the state of New Hampshire or elsewhere, and to transact any and all lawful business for which corporations may be incorporated under New Hampshire revised Statutes Annotated Chapter 293-A.[9]

In sum, the Legislature has provided that Eversource has broad corporate authority to enter into contracts for pipeline capacity as necessary and proper to the conduct of its authorized business. Under the general principles of "implied repeal," this general authority may only be overridden by a specific legal limitation or restriction. The Restructuring Act includes no such explicit restriction. The Legislature obviously was aware of the corporate powers it had previously created and could have explicitly overridden those powers if it so desired.

This conclusion is bolstered by a decision of the New Hampshire Supreme Court regarding a challenge to the Concord Electric Company's (now Unitil) grant of a mortgage. In *American Loan Trust Co. v. General Electric Co.*, the challengers alleged that the mortgage was void "for want of authority on the part of the Concord Electric Company as a corporation to make it, the legislature never having given it express permission to mortgage any of its property,

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[6] *Id.* at Art. II(1) (1926).
[7] *Id.* at Art. II(2).
[8] *Id.* at Art. II(4).
[9] State of New Hampshire, Record of Organization of Public Service Company of New Hampshire, *Amended Articles of Agreement of Public Service Company of New Hampshire,* at Art. II (1991).

rights, or franchises, and the corporation itself being of such a public character that due performance of its obligations to the public" was "inconsistent with a voluntary disposition of its property... ."[10] The Court disagreed, stating:

> The Concord Electric Company was formed under the general law of the state. This provides that any five or more persons of lawful age may associate together by articles of agreement to form a corporation for certain specified purposes, and for "the carrying on of any lawful business except banking, life insurance, the making of contracts for the payment of money at a fixed date or upon the happening of some contingency, and the construction and maintenance of railroads." P. S., c. 147, s. 1. When the articles are recorded as required, and the charter fee, if any, is paid, the signers become a corporation, "and such corporation, its officers and stockholders, shall have all the rights and powers and be subject to all the duties and liabilities of other similar corporations, their officers and stockholders, except so far as the same are limited or enlarged by this chapter." Ib., s. 4. *Among the powers expressly granted to such corporations is the power to make "contracts necessary and proper for the transaction of their authorized business,"* and to "purchase, hold, and convey real and personal estate necessary and proper" for such purpose, not exceeding the amount authorized by their charter or by statute. P. S., c. 148, ss. 7, 8.[11]

Eversource has the same "necessary and proper" authority to enter contracts today that the Concord Electric Company did when it was incorporated in 1901.

Since "[t]he most compelling reason to restructure the New Hampshire utility industry is to reduce costs for all consumers,"[12] it was unreasonable for the Commission to interpret the Restructuring Act as implicitly precluding Eversource's proposal, especially given the Commission's recognition of the cost and price volatility issues currently affecting wholesale electricity markets in New Hampshire and universally attributed to gas pipeline constraints.

[10] *American Loan Trust Co. v. General Electric Co.,* 71 N.H. 192, 195 (1901).
[11] *Id.* at 199-200 (emphasis supplied).
[12] RSA 374-F:1.

Respectfully submitted this 14th day of November, 2016.

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603-410-1500

CERTIFICATE OF SERVICE

I hereby certify that, on the date written below, I caused the attached to be served pursuant to N.H. Code Admin. Rule PUC 203.11.

Date: November 14, 2016

Peter W. Brown
Peter W. Brown, Esq.

THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 16-241

Public Service Company of New Hampshire d/b/a Eversource Energy
Petition for Approval of a Gas Capacity Contract with Algonquin Gas Transmission, LLC,
Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery

OBJECTION OF CONSERVATION LAW FOUNDATION TO MOTIONS FOR REHEARING AND/OR RECONSIDERATION

Pursuant to Puc 203.07(f), Conservation Law Foundation ("CLF") respectfully objects to the motions for rehearing and/or reconsideration filed on November 7, 2016 by Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource") and Algonquin Gas Transmission, LLC ("Algonquin"), as follows:

1. On October 6, 2016, the Commission issued Order No. 25,950 dismissing Eversource's petition requesting approval of a contract to purchase capacity on the proposed Access Northeast gas pipeline, related program details, and a distribution rate tariff ("Order"). The Order addressed a number of well-defined legal questions triggered by Eversource's unprecedented proposal – issues that had been the subject of extensive briefing (through both initial and reply briefs) by numerous parties, including but not limited to Eversource and Algonquin.

2. On November 7, 2016, Eversource and Algonquin filed separate motions for rehearing and/or reconsideration, arguing that the Commission reached an incorrect conclusion in dismissing Eversource's petition. Eversource's and Algonquin's motions fail to establish that the Commission overlooked or mistakenly conceived of matters in its Order and present no new,

previously unavailable information, effectively re-asserting matters that have been the subject of extensive briefing yet seeking a different result. Accordingly, their motions should be denied.[1]

3. Eversource and Algonquin assert that the Commission erroneously interpreted New Hampshire restructuring law, RSA 374-F, by improperly emphasizing competition and the functional separation of electric generation from electric transmission/distribution, as compared to the objective of reducing electricity rates. *See* Eversource Motion for Reconsideration at 2-3; Algonquin Motion for Rehearing and/or Reconsideration at 4-6. In doing so, Eversource and Algonquin fail to raise anything new[2] and fail to recognize that competition and unbundling the functions of traditional, vertically integrated utilities were the essential means by which the legislature chose to achieve lower rates. *See e.g.*, RSA 374-F:1, I ("The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity *by harnessing the power of competitive markets.*") (emphasis added). More specifically, while it is true that New Hampshire's restructuring law was enacted to reduce rates for consumers, the plain language of the law – entitled "Electric Utility *Restructuring*"[3]– evinces a clear, unambiguous intent[4] to achieve lower rates through a new structure that separates electric

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[1] As the Commission recently stated in *PNE Energy Supply, LLC, et al. v. PSNH d/b/a Eversource Energy*, DE 15-491, Order No. 25,693 (Nov. 9, 2016):

> The Commission may grant rehearing or reconsideration for "good reason" if the moving party shows that an order is unlawful or unreasonable. *See* RSA 541:3, RSA 541:4; Rural Telephone Companies, Order No. 25,291 (November 21, 2011). A successful motion must establish "good reason" by showing that there are matters the Commission "overlooked or mistakenly conceived in the original decision," *Dumais v. State*, 118. N.H. 309, 311 (1978) (quotations and citations omitted), or by presenting new evidence that was "unavailable prior to the issuance of the underlying decision," Hollis Telephone Inc. Order No. 25,088 at 14 (April 2, 2010). A successful motion for rehearing must do more than merely restate prior arguments and ask for a different outcome. Public Service Co. of N.H., Order No. 25,676 at 3 (June 12, 2014); *see also* Freedom Energy Logistics, Order No. 25,810 (September 8, 2015).

[2] The Commission's Order specifically acknowledges the argument that Eversource and Algonquin now re-assert, stating: "The Supporters' [of Eversource's petition] basic argument is that RSA Chapter 374-F, the electric utility restructuring statute, was intended to lower energy prices and that an EDC's purchase of gas capacity to be used by generators could further that intent." Order at 4.

[3] A statute's title "is a significant indication of the intent of the legislature in enacting a statute." *See Greenland Conservation Comm'n v. N.H. Wetlands Council*, 154 N.H. 529, 534 (2006) (citations omitted).

[4] The Commission properly engaged in an interpretation based on the plain and ordinary meaning of the statutory language, taking into account the overall regulatory scheme. Because the statute is not ambiguous, the Commission

generation from electric transmission/distribution, that fosters competition, and – of critical importance – prevents electric ratepayers from bearing the risks of generation-related investments by utilities. It is particularly noteworthy that in strenuously emphasizing the objective of lower electric rates, neither Eversource nor Algonquin even acknowledge the critically important principle of protecting ratepayers from economic risk – a consideration that the Commission properly considered in its legal analysis. *See* Order at 8-9 ("The competitive generation market is expected to produce a more efficient industry structure and regulatory framework, *by shifting the risks of generation investments away from customers of regulated EDCs toward private investors in the competitive market.* The long-term results should be lower prices and a more productive economy.") (emphasis added); *id.* at 9 ("A more efficient structure involves *placing investment risk on merchant generators who can manage that risk*, and allowing customers to choose suppliers, thus enabling customers to pay market prices *and avoid long-term over market costs*.") (emphasis added).

4. Eversource and Algonquin argue that the Commission somehow erred in assessing the interplay between RSA Chapter 374-F and other statutes, such as RSA 374-A (argued by both Eversource and Algonquin) and RSA 374:57 (argued by Algonquin). Again, they fail to raise issues not previously considered by the Commission and, in re-asserting their arguments, fail to acknowledge the transformative effect of New Hampshire's "Electric Utility *Restructuring*"[5] statute both on its own and with respect to statutes pre-dating a restructured industry.

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need not and should not consider legislative history, such as statements made by individual legislators and legislative committees set forth in Algonquin's Motion for Rehearing and/or Reconsideration. *See State v. Spade*, 161 N.H. 248, 251 (2010) (legislative history considered only when statute is ambiguous).

[5] RSA Chapter 374-F (emphasis added).

5. In sum, Eversource and Algonquin – in a last ditch attempt to obtain approval for a scheme that would undermine competition, that would directly contravene the legislature's deliberate restructuring of utilities to separate electric generation from electric transmission/distribution,[6] and that would force Eversource ratepayers to bear an economic risk that belongs with private investors – have provided no basis for the Commission to grant their motions for reconsideration and/or rehearing.

WHEREFORE, Conservation Law Foundation respectfully requests that the Commission deny Eversource's Motion for Reconsideration and Algonquin's Motion for Rehearing and/or Reconsideration.

Respectfully submitted,

CONSERVATION LAW FOUNDATION

Thomas F. Irwin

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Dated: November 15, 2016

[6] The deliberate nature of the legislature's restructuring of the electric utility industry is reinforced by RSA 374-F:3,III, which addresses the functional separation between generation and transmission/distribution services, but which specifically states: "However, distribution service companies should not be absolutely precluded from owning small scaled distributed generation resources as part of a strategy for minimizing transmission and distribution costs." Had the legislature intended electric distribution companies like Eversource to have the authority to acquire natural gas capacity for electric generation purposes, it would have stated such intent explicitly.

CERTIFICATE OF SERVICE

I hereby certify that a copy of this pleading has been sent by email to the service list in Docket No. DE 16-241 on this 15th day of November, 2016.

Thomas F. Irwin

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire

Petition for Approval of Gas Infrastructure Contract with Algonquin Gas Transmission, LLC

Docket No. DE 16-241

Opposition of the Office of the Consumer Advocate to Motions for Rehearing and Reconsideration

NOW COMES the Office of the Consumer Advocate ("OCA"), a party in this docket, and objects to the Motion for Rehearing and/or Reconsideration filed on November 7, 2016 by intervenor Algonquin Gas Transmission, LLC (Algonquin), the Motion for Reconsideration filed on the same date by petitioner Public Service Company of New Hampshire d/b/a Eversource Energy (PSNH), and the "Response" filed by the Coalition to Lower Energy Costs (CLEC) on November 14, 2016. In support of this opposition the OCA states as follows:

1. On October 6, 2016, the New Hampshire Public Utilities Commission issued Order No. 25,950 in this docket, dismissing the petition of PSNH with prejudice on the ground that the determinations requested by PSNH are inconsistent with New Hampshire law. Pursuant to N.H. Code Admin. Rules 203.05 and 203.07 as well as RSA 541:3, Algonquin and PSNH separately filed timely motions for rehearing (although PSNH styled its motion as one for reconsideration). The submission of such a timely rehearing motion is a prerequisite for any appellate proceedings that may ensue. *See* RSA 541:4 (additionally specifying that any ground not asserted in such a rehearing motion may not be heard on appeal).
2. The essence of the arguments on rehearing as made by both Algonquin and PSNH is that the Commission fundamentally misunderstood the purpose of the Electric Industry

Restructuring Act, RSA 541-F, to be fostering competition in the electric industry rather than achieving reductions in electricity rates. This is a mistaken assertion.

3. Almost 30 years ago, in a *per curiam* opinion, the U.S. Supreme Court made an important observation about statutory interpretation and, in particular, about the quest to discern legislative intent. The justices observed: "Deciding what competing values will or will not be sacrificed to the achievement of a particular objective is the very essence of legislative choice – and it frustrates rather than effectuates legislative intent simplistically to assume that *whatever* furthers the statute's primary objective must be the law." *Rodriguez v. United States*, 480 U.S. 522, 526 (1987).

4. The two pending rehearing motions essentially urge the Commission to make precisely that sort of simplistic assumption with respect to the Restructuring Act, something the Commission wisely opted not to do in Order 25,950. The Commission should for that reason deny the two pending rehearing motions. The rest is commentary, as enumerated *infra*.

5. Both Algonquin and PSNH claim that the Commission erred in its conclusion that the "overriding purpose" of the Restructuring Act is "to introduce competition to the generation of electricity." Algonquin Motion at 4; PSNH Motion at 2; Order No. 25,950 at 8. According to Algonquin and PSNH, the Commission overlooked the true overriding purpose of the Restructuring Act, which was to reduce the cost of electricity to New Hampshire customers. This is a simplistic and therefore flawed claim.

6. The statutory references to unwelcomely high electricity rates cited in both rehearing motions prove nothing beyond the very obvious point that *all* policymakers, be they legislators, governors, regulators and most certainly consumer advocates, want customers

to pay electric bills that are as low as possible and definitely lower than the unreasonably high ones that applied 20 years ago in the aftermath of the Seabrook-induced PSNH bankruptcy. The Legislature could not, and did not, declare by fiat that bills must fall; that would raise the specter of confiscatory rates in violation of the Takings Clause of the U.S. Constitution. Instead, the Legislature in 1996 declared the reduction of costs to be the "most compelling reason" to adopt a particular public policy "goal" – that of "a more efficient industry structure and regulatory framework." RSA 374-F:1, I. Thus, to the extent the answer here turns on the purpose statement in the Restructuring Act, the principles of plain language that guide statutory interpretation support rather than undermine the Commission's decision that "competition, furthered by restructuring and unbundling, is the ultimate purpose of the statutory scheme." Order No. 25,950 at 8.

7. These arguments about overriding purposes notwithstanding, the answer here – i.e., the ruling the Commission actually made in Order No. 25,950 – is not a contest between whether lowering costs is more important than promoting competition but is, rather, a determination that the capacity contract proposed by PSNH is "a component of 'generation services' under RSA 374-F:3, III." *Id.* The Commission's key legal conclusion is that "[i]ncluding such a generation-related cost in distribution rates would combine an element of generation costs with distribution rates and conflict with the functional separation principle." *Id.* This, of course, refers to the third of the 15 Restructuring Policy Principles enumerated in Section 3 of the Restructuring Act. By "functional separation principle" the Commission means the legislative determination in RSA 374-F:3, III that "[g]eneration services should be subject to market competition and minimal economic relation and at least functionally separated from transmission and

transmission and distribution services which should remain regulated for the foreseeable future." Neither the Algonquin nor the PSNH motion attack this legal conclusion head-on because they cannot. Forcing retail electric customers to pay generation-related costs in distribution rates is the very opposite of the market competition to which these costs must now be subject as a matter of New Hampshire law. The Commission was unassailably correct in saying so.

8. According to Algonquin, the PSNH petition does not transgress the functional separation principle because the firm natural gas capacity PSNH proposes to acquire from an affiliate's pipeline "will be auctioned by a capacity manager in an arm's length process consistent with Federal Energy Regulatory Commission (FERC) rules on capacity release." Algonquin Motion at 10. What Algonquin omits to mention is that on August 31, 2016, the FERC resoundingly rejected its proposal to provide PSNH (and other electric distribution utilities that cut similar deals with the Access Northeast project Algonquin is jointly developing with National Grid and a PSNH affiliate) for a blanket exemption under the Natural Gas Act from bidding requirements that would otherwise apply when releasing pipeline capacity to natural gas generators. *See Algonquin Gas Transmission, LLC*, 156 FERC ¶ 61,151 (Aug. 31, 2016) at ¶ 23 (though the FERC authorized the use of asset managers by such utilities). The FERC concluded that the Algonquin proposal does not meet the FERC's standard for such bidding exemptions: that of "improving the competitive structure of the natural gas industry." *Id.* at ¶ 34 (noting that the Algonquin proposal "would unnecessarily shield electric generators from the full effect of market forces acting on the natural gas price by excluding non-generators from the bidding process"). The point here is not to embroil the Commission

in questions related to the Natural Gas Act (something the Commission, reasonably, declined to do at pages 14-15 of Order No. 25,950) but rather to point out the congruity as a logical matter between the FERC's concern (possible end-runs around competition in wholesale natural gas markets) and the Commission's implicit determination that what PSNH is proposing here is at fundamental variance with the paradigm of a restructured industry.

9. Algonquin further contends that the Commission erred by ignoring the other 14 Restructuring Policy Principles in RSA 374-F:3. This is the equivalent of attempting to justify a homicide on the ground that nine of the Ten Commandments do not prohibit such conduct.[1]

10. Algonquin contends the Commission erred in its interpretation of RSA 374:57, which authorizes electric utilities to seek Commission approval of certain agreements "for the

[1] In the course of claiming that the Commission has inappropriately ignored 14 of the 15 Restructuring Policy Principles, Algonquin contends that "numerous regulators and stakeholders" have recognized that "New England's increasing reliance on natural gas for electric generation, without a corresponding expansion of natural gas infrastructure, threatens reliability." Algonquin Motion at 9. Although the PSNH petition and accompanying testimony are riddled with references to reliability, PSNH has presented no direct evidence to the effect that the lights will go out anywhere in New England unless electric distribution companies contract for firm natural gas capacity in the manner contemplated by the petition. In fact, the document at the heart of the petition – the ICF Report entitled "Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England Customers" – notably avoids making such a claim, arguing instead that "[b]y providing secure fuel supplies to [natural gas] generators and LNG facilities, Access Northeast *could* improve electric reliability across the grid." Attachment EVER-KRP 2 to Testimony of Kevin R. Petak at 9 (emphasis added); *see also id.* at 31 ("By providing secure fuel supplies to these generators, Access Northeast *could* significantly improve electric reliability across the grid") (emphasis added). Proponents of the Access Northeast project, aided and abetted by the CEO of the regional transmission organization, have consistently sought to conflate the claimed market benefits of the Access Northeast project with reliability benefits. *See, e.g.* "'Precarious:' New England's energy crisis," New Hampshire Union Leader, Oct. 2, 2016, available at http://www.unionleader.com/Editorial/Precarious-New-Englands-energy-crisis-10032016 (quoting ISO New England's CEO and claiming that "[t]he New England electric grid is starting to resemble California's two decades ago"). This is almost certainly because PSNH and Algonquin know they cannot argue that the region's electricity grid will be more reliable – i.e., that there will be fewer system failures – if the Access Northeast project goes forward and the attendant financial risk is placed on the backs of electricity customers.

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purchase of generating capacity, transmission capacity or energy" at the same time such agreements are filed with the FERC pursuant to the Federal Power Act. Notably, PSNH does not make this argument, which does not even deserve the badge of plausibility the Commission attached to it in the course of rejecting it. *See* Order No. 25,950 at 13 ("While the Supporters' reading of the statute is plausible, we believe the Opponents have the better argument"). As the Commission correctly concluded, RSA 374:57 is unambiguously a statute that governs *electric* generation and *electric* transmission – hence the reference in the statute to FERC approvals under the Federal Power Act with no corresponding reference to the Natural Gas Act. Notably, this is directly analogous to the recent ruling of the Supreme Judicial Court of Massachusetts that the phrase "the purchase of gas or electricity" in a statute similar to RSA 374-A plainly did not mean an electric utility could purchase natural gas capacity; that authority is reserved under the statute to gas utilities. *See Engie Gas & LNG LLC v. Department of Pub. Utils*., 475 Mass. 191, 203-205 (2016) (further concluding that to hold otherwise would be "untenable" in light of the Massachusetts restructuring statute).

11. Both Algonquin and PSNH contend that by ruling the petition inconsistent with New Hampshire law the Commission essentially deemed another statute -- RSA 374-A – repealed by implication. They focus on language in RSA 374-A:2 authorizing electric utilities to "plan, finance, construct, purchase, operate, maintain, use, share costs of, own, mortgage, lease, sell, dispose of or otherwise *participate in* electric power facilities or portions thereof within or without the state" (emphasis added). The statute likewise authorizes electric utilities to enter into contracts for such proposes. The Commission concluded that RSA 374-A "no longer applies" to electric distribution companies because

they no longer "participate in the generation side of the electric industry." Order No. 25,950 at 14.

12. On this point, the OCA agrees with Algonquin – that PSNH's proposed acquisition of firm natural gas capacity does not amount to "participat[ing] in" electric power facilities as that phrase is used in RSA 374-A:2. *See* Algonquin Motion at 15 (arguing that because "generators will continue to own, operate and retain their interests in the electric power facilities . . . Eversource will not be participating in electric power facilities"). Therefore, RSA 374-A does not provide statutory authorization for what PSNH is proposing here, and thus there is no implied repeal of RSA 374-A by virtue of later enactments that preclude the granting of the PSNH petition.

13. PSNH implies that the Commission should reconsider Order No. 25,950 on the ground that it is contrary to the State Energy Strategy issued by the Office of Energy and Planning in 2014, which acknowledges a need for additional natural gas pipeline capacity. RSA Chapter 4E governs the ongoing development of this document, but PSNH does not contend that the Commission violated this provision in Order No. 25,950. The Order does not reject any of the conclusions in the State Energy Strategy but merely points out that, in light of applicable limitations on what electric distribution companies may do, it falls to natural gas utilities to meet any additional need for pipeline capacity. Moreover, the references to pipeline constraints in the State Energy Strategy must be considered in their context. A fair reading of the relevant provisions is that (1) the ISO New England winter reliability program, which has led to increased use of backup generation fuels like oil and liquefied natural gas, is the right strategy for addressing natural gas supply constraints during extreme winter conditions, and (2) generally,

policies that increase fuel diversity rather than double down on the region's already too-great reliance on natural gas are in the best interests of New Hampshire consumers. *See* Office of Energy and Planning, New Hampshire 10 Year State Energy Strategy, available at https://www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf, at 15 (referring to the need for "cleaner, more diverse and more affordable energy").

14. Neither Algonquin nor PSNH offer any real challenge to the fundamental determination in Order No. 25,950 that "expenses related to generation supply would be disallowed in distribution rates" based on the "used and useful requirement . . . a basic component of utility ratemaking under New Hampshire law." Order No. 25,950 at 14. Algonquin objects to this determination in conclusory fashion, *see* Algonquin Motion at 15, and PSNH makes no mention of it. This is telling because, as the OCA has argued previously, the Electric Industry Restructuring Act is lodged squarely within longstanding principles of utility law. Ratepayers of PSNH are captive customers; the Restructuring Act partially released them from that captivity because the Legislature believed that in such freedom would lie cheaper but still reliable electricity. To the extent PSNH customers remain captive, they can only be forced to pay for transmission and distribution service – nothing else. The region may or may not need more natural gas capacity, but unless or until the Legislature says otherwise the financial responsibility for providing such capacity lies with the shareholders of investor-owned firms. That transfer of business risk is the essence of restructuring; the transfer itself left the basic premises of utility regulation intact.

15. On November 14, 2016, the Coalition to Lower Energy Costs (CLEC) – "a nonprofit association of individual consumers, labor unions, larger energy consumers and

institutions concerned about the threat to New England's families and economy from skyrocketing natural gas and electric prices,"[2] filed a pleading entitled "Response . . . to Algonquin and Eversource Motion for Reconsideration." This pleading is time-barred and the Commission should reject it on that basis.

16. RSA 541:3 provides that "[w]ithin 30 days after any order or decision has been made by the commission, any party to the action or proceeding before the commission, or any person directly affected thereby, may apply for a rehearing in respect to any matter determined in the action or proceeding, or covered or included in the order, specifying in the motion all grounds for rehearing, and the commission may grant such rehearing if in its opinion good reason for the rehearing is stated in the motion." N.H. Code Admin. Rules Puc 203.07(f) provides that *objections* to an RSA 541:3 motion for rehearing may be filed within five days of the date on which the motion for rehearing is filed."

17. The CLEC pleading is not an objection to a rehearing motion even though it purports to have been filed pursuant to Rule Puc 203.07(f). As the CLEC pleading plainly recites, "CLEC agrees with the arguments presented by AGT and Eversource, and offers the following arguments in support of the motions." CLEC then goes on to make eight pages of additional argumentation in favor of rehearing, (1) offering as a thesis the notion that the Commission should grant rehearing in light of "market failure" and (2) claiming that because the general corporate law does not withhold from PSNH the authority to contract for firm natural gas capacity and impose the associated costs on its captive customers, the Commission's interpretation of the Restructuring Act in Order 25,950 is erroneous. On the former point, CLEC appears to claim that, at the very least, the Commission should have taken evidence on the state of wholesale electricity markets so as to "give real life to the legal

[2] http://www.energycostcrisis.com/about-us/.

issues the Commission is asked to consider." CLEC Pleading at 4. Thus, CLEC is attempting to provide an additional twist to the Eversource and Algonquin arguments about the Restructuring Act and has, by invoking general corporate law, is seeking to introduce an entirely new ground for rehearing.

18. The Commission is precluded by statute from entertaining these arguments because, in effect, CLEC has filed a third rehearing motion – one that was submitted beyond the 30 days provided for in RSA 541:3. Although the Commission is frequently, and laudably, forgiving about deadlines, such flexibility would be both unfair and illegal here. RSA 541:4 provides that any argument not duly made in a rehearing motion pursuant to RSA 541:3 is waived for purposes of subsequent appeal. The untimely nature of the CLEC motion means the Commission and ultimately the New Hampshire Supreme Court lack jurisdiction to consider the grounds CLEC has asserted in its motion. *See, e.g., Radziewicz v. Town of Hudson*, 159 N.H. 313, 315 (2009) ("The superior court has no discretion when dealing with statutory time requirements that confer jurisdiction") (citation omitted). The Commission should so declare.

19. Finally, the OCA draws the Commission's attention to the pending motion of PSNH for confidential treatment of the key provisions of the key documents in this case -- and the OCA's opposition to the motion. Assuming, as is reasonable, that the outcome of the Commission's decision on rehearing will be further proceedings in the near term, either before the Commission or the New Hampshire Supreme Court, and further assuming that the Legislature may take up questions related to this docket in its upcoming session, the Commission should deem the confidentiality motion to be fully ripe for decision.

WHEREFORE, the OCA respectfully request that this honorable Commission:

A. Deny the pending motions for rehearing and/or reconsideration as well as for confidential treatment,

B. Reject the filing of the Coalition to Lower Electricity Costs as time-barred;

C. Issue a ruling on the pending motion for confidential treatment; and

D. Grant any other such relief as it deems appropriate.

Sincerely,

/s/ D. Maurice Kreis

D. Maurice Kreis
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November 15, 2016

Certificate of Service

I hereby certify that a copy of this Objection was provided via electronic mail to the individuals included on the Commission's service list for this docket.

/s/ D. Maurice Kreis

D. Maurice Kreis

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DE 16-241

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

Petition for Approval of a Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery

OBJECTION TO MOTIONS FOR REHEARING AND/OR RECONSIDERATION OF ORDER NO. 25,950

NOW COMES NextEra Energy Resources, LLC ("NEER"), and respectfully submits its Objection to the November 7, 2016 Motion for Reconsideration filed by Eversource Energy ("Eversource") and the Motion for Rehearing and/or Reconsideration filed by Algonquin Gas Transmission, LLC ("Algonquin") (together, "the Motions" or "the Movants"). At the core of the Movants' protestations is a refusal to accept the Commission's determination that the Restructuring Statute requires the separation of generation and distribution services, and the associated unbundling of the respective costs. However, the arguments presented in the Motions were previously presented to the Commission, and, in Order No. 25,950, the Commission correctly rejected the contentions as inconsistent with the rules of statutory construction and interpretation. Accordingly, as established below, the Motions fail to meet the standard of review for rehearing and reconsideration, and, further, the Motions are incorrect on the law. Therefore, NEER requests that the Commission deny the Motions.

I. Introduction

On February 18, 2016, Eversource filed a Petition for the approval of a proposed 20-year contract with Algonquin for natural gas capacity on Algonquin's Access Northeast Pipeline Project ("ANE Contract") and recovery of associated costs through a new distribution rate tariff that would be applied to all Eversource customers. On March 24, 2016, the Commission issued an Order of Notice that requested briefs from Eversource, Staff and other parties on the legality of the ANE Contract under New Hampshire law. Briefs were filed on April 12, 2016 and Reply Briefs on May 12, 2016. With consideration of these legal briefs, the Commission on October 6, 2016, dismissed Eversource's Petition as impermissible under New Hampshire law.[1]

In Order No. 25,950, based on a thorough review of the Electric Utility Restructuring statute, RSA Chapter 374-F ("Restructuring Statute"), the Commission found that the overriding purpose of the Restructuring Statue was to introduce competition into the generation of electricity.[2] This conclusion was well-supported by the Statute:[3]

> I. The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. . . . Increased customer choice and the development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry that will require unbundling of prices and services and at least functional separation of centralized generation services from transmission and distribution services.
>
> II. A transition to competitive markets for electricity is consistent with the directives of part II, article 83 of the New Hampshire constitution which reads in part: 'Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it.' Competitive markets should provide electricity suppliers with incentives to operate efficiently and cleanly, open markets for new and improved technologies, provide electricity buyers and sellers with appropriate price signals, and improve public confidence in the electric utility industry.

The Commission further concluded that the statute intentionally shifted the risks

[1] *Petition for Approval of Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery*, DE 16-241, Order Dismissing Petition, Order No. 25,950 (October 6, 2016) ("Order No. 25,950").

[2] *Id.* at 8.

[3] RSA 374-F:1.

associated with generation investments away from customers and toward private investors in the competitive market.[4] To effectuate the purpose of the Restructuring Statute, RSA 374-F:3, III requires the separation of generation services from transmission/distribution activities and services, and the unbundling of rates among these services.[5] The Commission supported this conclusion explaining that:[6]

> This purpose is underscored by the Legislature's recent strong encouragement, through the passage of HB 1602 and SB 221, to approve the 2015 Settlement Agreement that will accomplish the functional separation of Eversource's generation activities from its distribution activities.

With the above discernment on the purpose and directives of the Restructuring Statute, the Commission determined that the ANE Contract was "fundamentally inconsistent" with the statute, as it was a generation service under RSA 374-F:3, III seeking recovery of its net costs from electric distribution customers. Specifically, the Commission concluded that:[7]

> . . . the Capacity Contract is a component of 'generation services' under RSA 374-F:3, III, which *requires unbundled, clear price information for the cost components of generation, transmission, and distribution*. The acquisition of the gas capacity is clearly related to an effort to serve New England gas-fired electric generators with less expensive, more reliable fuel supplies. *Including such a generation-related cost in distribution rates would combine an element of generation costs with distribution rates and conflict with the functional separation principal.* (emphasis added).

With the determination that the "basic premise" of Eversource's ANE Contract proposal "runs afoul of the Restructuring Statute's functional separation requirement," the Commission

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[4] Order No. 25,950 at 8-9.

[5] *Id.* at 9.

[6] *Id.*

[7] *Id.*

could have concluded its analysis and dismissed the Petition as inconsistent with New Hampshire law. Nonetheless, the Commission further analyzed whether there was another statute that standing alone would support the Eversource proposal, and, if so, how the statute(s) would be affected by the subsequent enactment of the Restructuring Statute, or otherwise not applicable or supportive of the proposal.[8] The Commission's additional legal analysis found no New Hampshire law supported the ANE Contract. Thus, the Commission dismissed the Eversource Petition as impermissible under New Hampshire law.

Against the Commission's well-reasoned decision, Eversource and Algonquin repeat their arguments that the ANE Contract is permissible under New Hampshire law, and that the Commission based its dismissal of the Petition on a narrow interpretation of the Restructuring Statute.[9] For the reasons set forth in this Objection, however, it is clear that the arguments of Eversource and Algonquin have failed to establish that the Commission erred in its interpretation of the Restructuring Statute, and, therefore, their Motions should be denied.

II. Standard of Review

The Commission's standard for granting or denying a rehearing or reconsideration request is well established. According to RSA 541:3, the Commission may grant rehearing or

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[8] *Id.* at 9-10.

[9] Eversource Motion at 2 states that:

> The Commission based its determination nearly entirely upon an unreasonably narrow interpretation of the New Hampshire Electricity Restructuring statute, RSA chapter 374-F… by finding that the overriding purpose of the Restructuring Law was to remove regulated utilities from the generation business.

Also, the Algonquin Motion at 3 states that:

> . . . [T]he Commission's conclusions concerning the overall goals and relationship between the principles of the Restructuring Statute (RSA Chapter 374-F) and interpretation of other statutes in light of its reading of the Restructuring Statute, are incorrect, unlawful and unreasonable.

reconsideration when a motion states a "good reason for the rehearing."[10] To show good reason, the movant must demonstrate that the Commission erred through presenting "new evidence that was unavailable at the original hearing, or by identifying specific matters that were either 'overlooked or mistakenly conceived.'"[11] Additionally, in doing so, the movant cannot "merely reassert prior arguments and request a different outcome."[12] Application of the standard of review to the Motions show that they repeat past arguments,[13] present incorrect legal theories, and provide no new evidence or persuasive argument that the Commission overlooked or mistakenly conceived any conclusion in Order No. 25,950. Thus, the Motions should be dismissed as meritless.

III. The Commission Correctly Applied the Principles of Statutory Construction

a. The Commission applied the correct rules of statutory construction and interpretation in dismissing Eversource's Petition

The Commission carefully and correctly applied the rules of statutory construction and interpretation established by the New Hampshire Supreme Court. The Commission outlined its approach to statutory construction and interpretation as follows:[14]

> . . . we apply traditional New Hampshire principles of statutory interpretation. The New Hampshire Supreme Court first looks to the language of the statute itself, and, if possible, construes that language

[10] RSA 541:3.

[11] *Verizon New Hampshire Wire Center Investigation*, Docket No. DT 05-083, DT 06-012, Order No. 24,629 at 7 (June 1, 2006), *quoting Dumais v. State*, 118 N.H. 309, 311 (1978).

[12] *See Verizon New Hampshire Wire Center Investigation*, Docket No. DT 05-083, DT 06-012, Order No. 24,629 at 7 (June 1, 2006).

[13] For example, Eversource in its Motion concedes that it is repeating past arguments considered and rejected by the Commission. Eversource Motion at 7, 9, note 11.

[14] Order No. 25,950 at 7.

> according to its plain and ordinary meaning. The Court interprets statutes in the context of the overall regulatory scheme and not in isolation. The goal is to determine the Legislature's intent. Further, the Court construes statutes, where reasonably possible, so that they lead to reasonable results and do not contradict each other. When interpreting a statute, the Court gives effect to all words in the statute and presumes that the legislature did not enact superfluous or redundant words. *See Appeal of Old Dutch Mustard Co., Inc.*, 166 N.H. 501 (2014); *State v. Collyns*, 166 N.H. 514 (2014). When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with the subject in a specific way and the earlier enactment treats that subject in a general fashion. *Board of Selectmen v. Planning Bd.*, 118 N.H. 150, 152 (1978); see also *Appeal of Pennichuck Water Works*, 160 N.H. 18, 34 (2010) (quoting *Appeal of Plantier*, 126 N.H. 500 (1985)).

The Commission applied these fundamental rules of statutory construction and interpretation throughout its consideration of the Restructuring Statute and other statutes. In contrast to the Commission's application of the rules of statutory construction, the Movants fundamentally misapply the rules in a misguided attempt to seek a different result that, if adopted, would be in violation of New Hampshire law.

b. The Commission correctly concluded that the plain language of RSA 374-F:3, III shows that the Petition is fatally flawed

The Commission properly applied the plain language doctrine to RSA 374-F:3, III, which, in pertinent part, reads:

> When customer choice is introduced, services and rates should be unbundled to provide customers clear price information on the cost components of generation, transmission, distribution, and any other ancillary charges. Generation services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services which should remain regulated for the foreseeable future.

Reading the plain language of this statute, the Commission found it "directs the restructuring of the industry, separating generation activities from transmission and distribution activities, and unbundling the rates associated with each of the separate services."[15] Thereafter, in a straightforward application of this plain language reading of RSA 374-F:3, III to the undisputed facts of the Eversource Petition, the Commission correctly concluded:[16]

> . . . the Capacity Contract is a component of 'generation services' under RSA 374-F:3, III, which requires unbundled, clear price information for the cost components of generation, transmission, and distribution. The acquisition of the gas capacity is clearly related to an effort to serve New England gas-fired electric generators with less expensive, more reliable fuel supplies. *Including such a generation-related cost in distribution rates would combine an element of generation costs with distribution rates and conflict with the functional separation principal*. . . .
>
> . . . the basic premise of Eversource's proposal – having an [electric distribution company] EDC purchase long-term gas capacity to be used by electric generators – runs afoul of the Restructuring Statute's functional separation requirement . . . . (emphasis added).

In reaction to this clear and well-reasoned ruling, the Movants repeat that an EDC is authorized to contract for capacity under RSA 374:57 and participate in generation power facilities under RSA 374-A.[17] The Movants also reiterate an "in the alternative" contention that the ANE Contract is not a generation activity, as it would "simply provide a mechanism by which natural gas capacity would be made available."[18] They further argue that the Commission erred in not accepting that RSA 374-A:2 and RSA 374-A:1, II and IV authorize Eversource to

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[15] *Id.* at 8.

[16] *Id.* at 9.

[17] *Compare* Eversource Motion at 4, 10 *with* Algonquin Initial Brief at 7-8 and Eversource Initial Brief at 13-14.

[18] Algonquin Motion at 9-10.

purchase gas capacity "regardless of restructuring."[19] All of these arguments were rejected by the Commission and are incorrect as a matter of law.

In large part, the Movants' reiterated disagreement turns on its view that RSA 374-A:2 and RSA 374-A:1 II and RSA 374-A:1, IV provide it with the statutory authority to engage in generation-related services, such as the ANE Contract.[20] These statutes do nothing of the sort.[21] Instead, the Movants have an elemental misunderstanding of the import of RSA 374-F, III on these statutes. As the Commission correctly determined:[22]

> The change in the industry through the Restructuring Statute, first passed in 1996, effectively ended a restructured EDC's ability to participate in the generation side of the electric industry. Given the centrality of the separation of functions between distribution and generation in the Restructuring Statute, allowing an EDC to 'participate in electric power facilities' under RSA 374-A in the manner proposed by Eversource would make little sense in light of RSA 374-F.

Enacted in 1975, RSA 374-A:1, IV sets forth a definition of what constitutes an electric utility, while RSA 374-A:2 adds that a domestic electric utility can "participate in electric power facilities." However, these general provisions do not provide specificity on how the electric utility will be regulated in a restructured environment – instead, the particulars of how an electric utility is regulated in a restructured environment, post 1996, is in the Restructuring Statue, and, specifically the separation requirements of RSA 374-F, III. That statute sets forth the specific regulatory conditions that services and rates be unbundled, and that generation be functionally separate from transmission and distribution. These separation requirements are the

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[19] Eversource Motion at 9.

[20] *Id.* at 4-12.

[21] RSA 374-A:1 simply states: "'A Domestic electric utility' means an electric utility resident in, or organized under the laws of this state." Thus, the analysis focuses on RSA 374-A:2 and RSA 374-A:1, IV.

[22] Order No. 25,950 at 14.

quintessential elements of the Restructuring Statute such that without the Commission enforcing them there would be no restructuring. Further, the tenets of statutory construction mandate that the later statute controls, particularly when the earlier statute addresses the subject in a general manner, and the later statute in a specific manner.[23] Thus, RSA 374-F:3, III controls; which, in turn, requires that, over the Movants' objections,[24] the mandatory *sine qua non* of RSA 374-F:3, III must be enforced: no Eversource generation service can be bundled with distribution and no generation service cost can be passed through Eversource's distribution customer rates. Therefore, not only have the Movants not presented any new argument, their repeated disagreement with the lack of applicability of the later-in-time statutes is not supported, and should be rejected.

c. The Commission correctly identified the overriding purpose of the Restructuring Statute

In Order No. 25,950, the Commission concluded that the "overriding purpose of the Restructuring Statute is to introduce competition to the generation of electricity."[25] The Commission further correctly identified that the separation requirements of RSA 374-F, III must be enforced to effectuate this overriding purpose, as well as the other provisions of the Restructuring Statute. The Movants argue, however, that the overriding purpose is to reduce electric rates, and, thus RSA 374-F, III cannot be construed in a manner that does not promote

[23] *In the Matter of Kathaleen A. Dufton and Terry L. Shepard, Jr.*, 158 N.H. 784, 789 (2009), *quoting Bel Air Assocs. v. N.H. Dep't of Health & Human Services*, 154 N.H. 228, 233 (2006) (The Court ruled the later grandmother visitation statute controlled over the earlier enacted general adoption law); *Petition of Public Service New Hampshire*, 130 N.H. 265, 281-284 (1988) (The Court ruled that the later in time prohibitions in the anti-CWIP statute controlled over the earlier in time general ratemaking statute).

[24] Eversource Motion at 6, note 10, 8-10; Algonquin's Motion at 4, 12-13.

[25] *Id.* at 8.

the reducing of costs and rates.[26] The Movants further maintain that the Commission's focus on competition in generation, and the separation requirements in RSA 374-F, III are at the expense of the other provisions and principles of the Restructuring Statute.[27] These reiterated arguments again fail for the same reason the arguments related to the general definitional statutes fail: without the separation of generation from distribution services/costs, and competition for generation, there is no restructuring.

Taking the Movants arguments to their logical conclusion, they would have the Commission selectively ignore RSA 374-F, III, and the promotion of generation competition throughout the Restructuring Statute, anytime the company predicts that over a 20-year period it can reduce distribution rates by rejoining generation services with distributions services. Movants, thus, are attempting to nullify RSA 374-F, III, and, by doing so, either distort or eliminate the fundamental elements of New Hampshire's electric restructuring. However, nullification of the customer protections intended by the unbundling of generation services/costs from distribution services/costs in RSA 374-F:3, III, is in violation of the established rules of statutory construction.[28] In contrast, the Commission's ruling on the overriding restructuring principle – the introduction of competition to the generation of electricity – does not nullify or eliminate the other principles as there are other means, consistent with restructuring, for the attainment of the other principles.

Further, the Movants' position is flawed because the other restructuring principles are permissible or general pronouncements, which is in clear contrast to RSA 374-F, III that is a

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[26] Eversource Motion at 2; Algonquin Motion at 4-5.

[27] *Id.* at 2-3; *Id.* at 6-9.

[28] *Richard Holt& a. v. Gary Keer & a.*, 167 N.H. 232, 242-243 (2015) (Court would not create an exception in one statute that nullified the protections in another statute).

directive requiring the separation of services and costs, and a directive that carries out the overriding principle of introducing competition to generation. First and foremost, the plain language of the Restructuring Statute directs the separation of generation from transmission and distribution, the former subject to market competition and the latter to regulation. Given the RSA 374-F, III separation requirements are plain from the text, the statutory interpretation inquiry ends with no consultation to the legislative history.[29] Second, even if the Commission were to consider legislative history, the selective quotes from the Movants ignore the remaining legislative history, which is replete with passages identifying the importance of the separation and generation competition provisions that are embodied in the plain language of the Restructuring Statute. Finally, interpreting the Restructuring Statute in the manner the Movants suggest would require the Commission to ignore the fundamental separation and competition provisions of Sections II and III of the Restructuring Statute, begging the question of whether the Statute restructured anything at all. The Commission was correct in rejecting these arguments in its Order. Movants have presented nothing new, much less established, that the Commission erred in so holding.

IV. The Commission Correctly Ruled that Eversource's Proposal to Purchase Natural Gas Capacity is a Generation Service that must be separated from Distribution Service and Costs

Algonquin repeats previously rejected arguments that a New Hampshire EDC is allowed to purchase natural gas capacity, as it is not a generation-related service. According to Algonquin, the ANE Contract will only make firm natural gas capacity available to generators,

[29] *See, e.g., Foster v. Town of Henniker,* 167 N.H. 745, 753-754 (2015); *Franklin v. Town of Newport*, 151 N.H. 508, 509-510 (2004).

which is not a generation service.[30] However, in Order No. 25,950, the Commission thoroughly analyzed these arguments and determined that the Restructuring Statute required a finding that the ANE Contract was a generation-related activity.[31] Specifically, the Commission ruled:[32]

> [W]e conclude that the Capacity Contract is a component of 'generation services' under RSA 374-F:3, III, which requires unbundled, clear price information for the cost components of generation, transmission, and distribution. The acquisition of the gas capacity is clearly related to an effort to serve New England gas-fired electric generators with less expensive, more reliable fuel supplies. Including such a generation-related cost in distribution rates would combine an element of generation costs with distribution rates and conflict with the functional separation principal.

Further, in Order No. 25,950, Commission referenced the Massachusetts Supreme Judicial Court's conclusion that "such a Capacity Contract would contradict the policy embodied in the Massachusetts restructuring act, which removed electric companies from the business of electric generation." [33] In reaching this conclusion, the Court found:[34]

> . . . the department itself has recognized that fuel procurement and planning is an integral component of the generation business, as evidenced by its exemption of electric distribution companies from § 69I. Indeed, by some estimations, fuel-related costs constitute seventy-five per cent of a natural gas-fired plant's generation costs. 3 World Scientific Handbook of Energy 72 (G.M. Crawley ed., 2013) . . . . We agree with the plaintiffs that if the restructuring act does not allow electric distribution companies to finance investments in electric generation, it cannot be reasonably interpreted to permit those companies to invest in infrastructure unrelated to electric distribution service.

[30] *Compare* Algonquin Motion at 10 *with* Algonquin Initial Brief at 7.

[31] Order No. 25, 950 at 7-9.

[32] *Id.* at 9.

[33] *Id.* at 2, note 1.

[34] *Engie Gas & LNG, LLC v. Department of Public Utilities*, 475 Mass. 191, 209; 56 N.E.3d 740, 754-755 (2016).

Although the Massachusetts Supreme Judicial Court decision is not dispositive of the issue in New Hampshire, it provides additional support for the well-reasoned decision of the Commission that the ANE Contract is a generation service under New Hampshire law. Algonquin's Motion provides no new evidence or argument on this subject, and, therefore, its arguments should be rejected as failing to show good reason for reconsideration or rehearing.

IV. The Commission Properly Ruled on the Import of Other Statutes in Dismissing Eversource's Petition

With regard to several statutes, the Movants set forth no argument that was not previously considered by the Commission, nor do Movants identify specific matters that were overlooked or mistakenly conceived by the Commission. For instance, the Movants repeat that the Commission erred in its statutory analysis, because: (i) the Restructuring Statute should be interpreted to permit EDCs to acquire gas capacity;[35] (ii) the least cost planning statutes, RSA 378:37 and 378:38, support Eversource's Petition;[36] (iii) the 10-Year New Hampshire State Energy Strategy referenced in RSA 378:38, VII, lends support to Eversource's Petition;[37] and (iv) the provisions of RSA 374:57 (purchase of capacity) support Eversource's Petition.[38]

Specifically, Movants reproduce their argument that the Restructuring Statute permits EDCs to acquire gas capacity, again arguing that in the Restructuring Statute "the Legislature did not prohibit utilities from providing electric supply, but gave the Commission the authority to

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[35] *Compare* Eversource Motion at 11 *with* Eversource Initial Brief at 10; *compare* Algonquin Motion at 4 *with* Algonquin Initial Brief at 6.

[36] *Compare* Eversource Motion at 6, note 10 *with* Eversource Reply Brief at 11 and Algonquin Reply Brief at 2.

[37] *Compare* Eversource Motion at 7 *with* Eversource Initial Brief at 9.

[38] *Compare* Algonquin Motion at 4 *with* Algonquin Reply Brief at 12-13.

determine how electricity supply services from a utility may be provided."[39] However, the Commission in Order No. 25,950 found on the basis of these arguments and applying the rules of statutory interpretation, that the Movants' arguments were unpersuasive, stating:[40]

> In weighing the restructuring policy principles of RSA 374-F, we agree with the Opponents and find that the overriding purpose of the Restructuring Statute is to introduce competition to the generation of electricity. The competitive generation market is expected to produce a more efficient industry structure and regulatory framework, by shifting the risks of generation investments away from customers of regulated EDCs toward private investors in the competitive market. The long-term results should be lower prices and a more productive economy. To achieve that purpose, RSA 374-F:3, III directs the restructuring of the industry, separating generation activities from transmission and distribution activities, and unbundling the rates associated with each of the separate services.

The Commission's decision on this issue is consistent with NEER's own interpretive analysis. In briefing this issue NEER stated:[41]

> The purpose of restructuring to a competitive supply market was to separate energy supply from transmission and distribution; the former to operate in a competitive market, the latter to remain a regulated natural monopoly. See, e.g., RSA 374-F:2, II (defining 'Electricity suppliers' to facilitate separation) and RSA 374-F:3, III (requiring unbundling of rates for generation and transmission and distribution components); see also RSA 369-B:2, IV & XII ('Electric utility' means a public utility . . . that provides retail electric service. . . . 'Retail electric service' means the delivery of electric power through the provision of transmission and/or distribution service by an electric utility to a retail customer . . . .').

Without presenting any new arguments, the Movants maintain that the Commission should

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[39] Eversource Motion at 12; Algonquin Motion at 3-4.

[40] Order No. 25,950 at 8-9.

[41] NEER Principal Brief at 6.

reconsider its well-reasoned decision that EDCs are not permitted under New Hampshire law to purchase gas capacity. The Movants clearly have failed to establish any good reason for reconsideration or rehearing.

Eversource also improperly repeats their arguments concerning the least cost planning statutes, specifically RSA 378:38, arguing that the Commission's decision runs counter to the policies of the State.[42] The Commission, however, did not ignore Eversource's earlier arguments on this issue.[43] To the contrary, the Commission addressed Eversource's position in Order No. 25,950, ruling that: [44]

> [W]e do not find that the [least cost planning] statutes permit the re-joining of distribution and generation functions in the manner provided by the Capacity Contract . . . The planning statutes must be read in concert with RSA 374-F and in light of the industries to which they apply.

Thus, Eversource's contentions were considered and rejected, and the company again fails to present new or overlooked argument that would suggest the Commission reconsider its ruling.

Eversource also argues that the 10-Year New Hampshire State Energy Strategy provides encouragement for companies, like Eversource, to increase gas pipeline capacity in New England. Specifically, Eversource contends that the Commission should reconsider Order No. 25,950 in light of the policies set forth in the State Energy Strategy.[45] The Commission,

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[42] Eversource Motion at 6, note 10.

[43] Eversource Initial Brief at 8 ("[T]hough the ANE Contract is not governed by the resource planning statutes, it supports other goals contemplated there. For example, the ANE Contract demonstrates that Eversource has engaged in a meaningful assessment of the energy supply options for the region as contemplated in RSA 378:38, III, and has found that there is a need to protect and enhance the supply.").

[44] Order No. 25,950 at 11.

[45] Eversource Motion at 6-7.

however, rejected earlier contentions stating the same position in Order No. 25,950.[46] In rejecting Eversource's argument, ruling that:[47]

> They [Supporters] claim that the Strategy thus requires EDCs to explore ways to increase gas pipeline capacity. We disagree. As discussed above, RSA 378:38 applies to both electric and gas utilities. Both are required to plan to have an adequate supply to meet their customers' demand. In our view, gas supply under the State Energy Strategy is the responsibility of the gas utilities. While Eversource, an EDC, cannot enter into the Capacity Contract and have it paid for through its distribution rates, natural gas utilities might be appropriate proponents of increased gas pipeline supply under RSA 378:38, VII.

Again, Eversource's Motion presents no new argument on this statute, and must be rejected as failing to present a good reason for reconsideration.

Similarly, Algonquin's Motion reiterates that the provisions of RSA 374:57 support Eversource's Petition. Algonquin claims that the legislature did not intend to limit the types of contracts permissible under RSA 374:57 to just electricity.[48] This same argument, however, was rejected by the Commission in its Order using the appropriate principles of statutory analysis:[49]

> While the Supporters' reading of the statute is plausible, we believe the Opponents have the better argument. The meaning of 'capacity' in that legislation is limited to electric generating capacity and electric transmission capacity. First, the types of agreements listed are commonly associated with electric supply. Second, if gas capacity was to be included, the statute would have included references to the Natural Gas Act in addition to the Federal Power Act. Thus we find that RSA 374:57 concerns long-term contracts for electric supply and does not authorize EDCs to purchase gas capacity under long-term contracts.

[46] Order No. 25,950 at 12.

[47] *Id.*

[48] Algonquin Motion at 12.

[49] Order No. 25,950 at 13.

This ruling was supported by the statutory analysis offered by other parties, including NEER. For example, NEER's brief stated that:[50]

> Suggesting that RSA 374:57 – which was inserted into the General Regulations as part of the larger agreement to end the PSNH bankruptcy through a reorganization agreement intended to establish tight controls on Eversource – should be read as somehow expanding Eversource's contracting ability to the point that it authorizes Eversource to circumvent the Restructuring Statute and allows the twenty-year, multi-billion dollar investment in natural gas pipeline capacity that it cannot use suggested by Eversource is simply unsupportable. The statute's purpose was to constrain, not expand, Eversource's contracting authority.

The Commission's interpretation of RSA 374:57 was well-reasoned, and Algonquin has provided no new argument to establish that the Commission erred in its interpretation of RSA 374:57. Therefore, Algonquin provides no good reason for the reconsideration or rehearing of the ruling.

V. Conclusion

In Order No. 25,950, the Commission correctly applied the rules of statutory construction and interpretation as articulated by the New Hampshire Supreme Court.[51] The Movants raise no new issues or arguments, and, therefore, fail to present a good reason for the Commission to reconsider or rehear its rulings in Order No. 25,950. Thus, for the reasons set forth in this Objection, the Commission should deny the Motions.

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[50] NEER Principal Brief at 30-31.

[51] Order No. 25,950 at 7.

Respectfully submitted,

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Dated November 15, 2016

CERTIFICATE OF SERVICE

I hereby certify that a copy of this pleading has been sent by email to the service list in Docket No. DE 16-241 on this 15th day of November, 2016.

____
Christopher T. Roach

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 16-241

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

Petition for Approval of Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery

Order Denying Motions for Reconsideration

ORDER NO. 25,970

December 7, 2016

The Commission hereby denies the motions for reconsideration of Order No. 25,950, which dismissed Eversource's petition in this docket.

I. PROCEDURAL BACKGROUND

On February 18, 2016, Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource), a New Hampshire electric distribution company (EDC) filed a petition for approval of a proposed 20-year contract with Algonquin Gas Transmission, LLC (Algonquin). The contract would have been for natural gas capacity on Algonquin's Access Northeast Pipeline Project (Access Northeast pipeline). Eversource also sought recovery of associated costs through a new distribution rate tariff, to be assessed on all of Eversource's customers. Following the submission of legal briefs by interested persons regarding the Eversource proposal, the Commission dismissed the petition. *See* Order No. 25,950 (October 6, 2016). In that order, the Commission concluded as a matter of law that Eversource's proposal conflicted with the principles and requirements of the Electric Restructuring Statute, RSA Chapter 374-F. For a more extensive description of the procedural history of this matter, together with the Commission's legal analysis regarding its decision to dismiss the petition, see Order No. 25,950.

On November 7, 2016, Eversource filed a timely motion for reconsideration of the Commission's decision to dismiss its petition. Algonquin also filed a motion for reconsideration on November 7, 2016. On November 14, 2016, the Coalition to Lower Energy Costs (CLEC) made a filing styled a "Response" to the Eversource and Algonquin motions for reconsideration, broadly supportive of the Eversource and Algonquin pleadings. On November 15, 2016, the Conservation Law Foundation (CLF) filed a timely objection to the Eversource and Algonquin requests for reconsideration. Also on November 15, 2016, the Office of the Consumer Advocate (OCA) filed a timely objection to the Eversource and Algonquin pleadings. On November 18, 2016, NextEra Energy Resources, LLC (NextEra) filed its own objection to the requests for reconsideration. The petition and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted to the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2016/16-241.html.

II. POSITIONS OF THE PARTIES

A. Eversource

In its motion for reconsideration, Eversource reiterated the core arguments it made in its previously filed legal briefs. Specifically, Eversource argued that the Commission erred in failing to adopt the position that the objective of "lower energy costs" presented by the Legislature within the terms of the Electric Restructuring Statute, RSA 374-F, enabled the Commission to approve the Eversource-Access Northeast pipeline proposal. Eversource disagreed with the Commission's reliance on competition and functional separation of distribution and generation as the core principles of the Restructuring Statute. Eversource Motion at 2-5. Eversource also argued that the New Hampshire State Energy Strategy supports the acquisition of additional pipeline capacity for use by New England generators. Eversource maintained that the prospect of "market failure" related to merchant generators' inability to acquire gas pipeline capacity militated in favor of the Commission's allowing the proposed activity. Eversource Motion at 5-7. Eversource also argued that RSA 374-A remains applicable to New Hampshire EDCs such as itself, even though Eversource did not rely on RSA 374-A in making its petition. Eversource Motion at 7-12.

B. Algonquin

In its motion for reconsideration, Algonquin alleged that the Commission ignored the various goal-oriented Restructuring Statute principles related to the perceived need for lower energy costs, among others, in favor of the functional separation principle presented in RSA 374-F:3, III, and the general principle of competition. Algonquin Motion at 3-9. Algonquin also reiterated its position that for Eversource to "simply provide a mechanism by which natural gas capacity would be made available" did not implicate RSA 374-F:3, III. Algonquin Brief at 9-11. Algonquin also argued that the Commission erred in not accepting legal arguments regarding the applicability of RSA 374:57 and RSA Chapter 374-A.

C. CLEC

In its pleading,[1] CLEC argued that the Commission was incorrect in concluding that the Eversource-Access Northeast proposal violated the terms of the Electric Restructuring Act. CLEC reiterated its position that there exists a state of "market failure" compelling the Commission to approve the proposal, that the proposal does not violate the functional separation principle of the Restructuring Act, and that the general corporate powers of Eversource enabled it to enter into the proposed activities. CLEC offered its broad support for the Eversource and Algonquin motions for reconsideration.

[1] CLEC's filing was not styled as request for rehearing or reconsideration. Instead, CLEC filed what it called a "response" to the motions of Eversource and Algonquin. The OCA argues that we should ignore CLEC's filing as untimely. In light of our decision, consideration of CLEC's arguments does not affect the result.

D. CLF

CLF opposed the requests for reconsideration, agreeing with the determinations of law made by the Commission in Order No. 25,950, and stated that there was no basis for the Commission to reconsider its decision.

E. OCA

The OCA supported the Commission's legal conclusion that the proposed Access Northeast contract would constitute a component of "generation services" in violation of the functional-separation principle of RSA 374-F:3, III, and the Electric Restructuring Act generally. *See* OCA Objection at 3-5. The OCA also presented arguments in opposition to Eversource's, Algonquin's, and CLEC's arguments regarding the import of the ancillary statutes considered by the Commission in its rulings.

F. NextEra

NextEra offered detailed analysis in support of the Commission's legal conclusions presented in Order No. 25,950.

III. COMMISSION ANALYSIS

The Commission may grant rehearing or reconsideration for "good reason" if the moving party shows that an order is unlawful or unreasonable. RSA 541:3, RSA 541:4, *Rural Telephone Companies*, Order No. 25,291 (November 21, 2011). A successful motion must establish "good reason" by showing that there are matters that the Commission "overlooked or mistakenly conceived in the original decision," *Dumais v. State*, 118 N.H. 309, 311 (1978) (quotation and citations omitted), or by presenting new evidence that was "unavailable prior to the issuance of the underlying decision," *Hollis Telephone Inc.*, Order No. 25,088 at 14 (April 2, 2010). A successful motion for rehearing must do more than merely restate prior arguments and ask for a different outcome. *Public Service Co. of N.H.,* Order No. 25,676 at 3 (June 12, 2014); *see also Freedom Energy Logistics*, Order No. 25,810 at 4 (September 8, 2015).

Eversource's and Algonquin's motions for reconsideration do not present any new information, nor do they establish that the Commission overlooked or misunderstood issues in connection with its dismissal of Eversource's petition by means of Order No. 25,950. We carefully reviewed all of the statutory authorities relied upon by both supporters and opponents of the Eversource proposal, including RSA Chapter 374-F, and did not develop our legal conclusions in a vacuum. Historical context was of critical importance in our analysis. For instance, we carefully examined the definition of "Electric utility" presented in RSA 374-A:I, IV, and noted that Eversource is no longer the kind of electric utility defined in that section as "any individual or entity or subdivision thereof, private, governmental or other, including a municipal utility, wherever resident or organized, primarily engaged in the generation and sale or the purchase and sale of electricity or the transmission thereof, for ultimate consumption by the public." We stand by our conclusions that "RSA 374-A no longer applies to an EDC like Eversource" and "[t]he change in the industry through the Restructuring Statute, first passed in 1996, effectively ended a restructured EDC's ability to participate in the generation side of the electric industry." *See* Order No. 25,950 at 13-14.

Eversource and Algonquin simply reiterated their arguments that the goals of RSA 374-F, including lower energy costs and concomitant economic benefits, override the requirement to divest, if some alternative means is presented that promises to lower energy costs. Restating prior arguments and requesting a different outcome is not grounds for rehearing. Therefore, Eversource and Algonquin's motions for reconsideration are denied.

Based upon the foregoing, it is hereby

ORDERED, that the petitions by Eversource and Algonquin for reconsideration are hereby DENIED.

By order of the Public Utilities Commission of New Hampshire this seventh day of December, 2016.

Martin P. Honigberg Chairman	Michael J. Iacopino Special Commissioner	Kathryn M. Bailey Commissioner

Attested by:

Debra A. Howland
Executive Director

SERVICE LIST - EMAIL ADDRESSES- DOCKET RELATED

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Docket #: 16-241-1 Printed: December 07, 2016

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
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b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

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HOUSE BILL - FINAL VERSION

1996 SESSION

3816L
96-2142
03/09

HOUSE BILL **1392**

AN ACT restructuring the electric utility industry in New Hampshire and establishing a legislative oversight committee.

SPONSORS: Rep. J. Bradley, Carr 8; Rep. Below, Graf 13; Rep. Guay, Coos 6; Rep. A. Merrill, Straf 8; Rep. Pfaff, Merr 11; Sen. Shaheen, Dist 21; Sen. Fraser, Dist 4; Sen. Cohen, Dist 24; Sen. Barnes, Dist 17; Sen. Rodeschin, Dist 8

COMMITTEE: Science, Technology and Energy

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ANALYSIS

This bill:

(1) Establishes a legislative oversight committee on electric utility restructuring.

(2) Requires all electric utilities to submit rate restructuring plans.

(3) Establishes restructuring principles to be used by the public utilities commission in assessing and approving each utility's restructuring plan.

(4) Requires the committee to submit an annual report on its progress. The first report shall be submitted on or before November 1, 1996, to the governor, the senate president and the speaker of the house.

EXPLANATION: Matter added to current law appears in **bold italics.**
Matter removed from current law appears in [brackets].
Matter which is either (a) all new or (b) repealed and reenacted appears in regular type.

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CHAPTER 129
HOUSE BILL - FINAL VERSION

3816L
96-2142
03/09

HB 1392

STATE OF NEW HAMPSHIRE
In the year of Our Lord
One Thousand Nine Hundred and Ninety-Six

AN ACT
restructuring the electric utility industry in New Hampshire
and establishing a legislative oversight committee.

Be it Enacted by the Senate and House of
Representatives in General Court convened:

129:1 Findings. The general court finds that:
I. New Hampshire has the highest average electric rates in the nation and such rates are unreasonably high. The general court also finds that electric rates for most citizens may further increase during the remaining years of the Public Service Company of New Hampshire rate agreement and that there is a wide rate disparity in electric rates both within New Hampshire and as compared to the region. The general court finds that this combination of facts has a particularly adverse impact on New Hampshire citizens.
II. New Hampshire's extraordinarily high electric rates disadvantage all classes of customers: industries, small businesses, and captive residential and institutional ratepayers and do not reflect an efficient industry structure. The general court further finds that these high rates are causing businesses to consider relocating or expanding out of state and are a significant impediment to economic growth and new job creation in this state.
III. Restructuring of electric utilities to provide greater competition and more efficient regulation is a nationwide phenomenon and New Hampshire must aggressively pursue restructuring and increased customer choice in order to provide electric service at lower and more competitive rates.
IV. Monopoly utility regulation has historically substituted as a proxy for competition in the supply of electricity but recent changes in economic, market and technological forces and national energy policy have increased competition in the electric generation industry and with the introduction of retail customer choice of electricity suppliers as provided by this chapter, market forces can now play the principal role in organizing electricity supply for all customers instead of monopoly regulation.
V. It is in the best interests of all the citizens of New Hampshire that the general court, the executive branch, and the public utilities commission work together to establish a competitive market for retail access to electric power as soon as is practicable and that interim stranded cost recovery charges be determined and put into effect for each utility operating in this state to expedite and facilitate the transition for such a market.
129:2 New Chapter; Restructuring of the New Hampshire Electric Utility Industry. Amend RSA by inserting after chapter 374-E the following new chapter:

CHAPTER 374-F
ELECTRIC UTILITY RESTRUCTURING

374-F:1 Purpose.
I. The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. Increased customer choice and the development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry that will require unbundling of prices and services and at least functional separation of centralized generation services from transmission and distribution services.
II. A transition to competitive markets for electricity is consistent with the directives of part II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it." Competitive markets should provide electricity suppliers with incentives to operate efficiently and cleanly, open markets for new and improved technologies, provide electricity buyers and sellers with appropriate price signals, and improve public confidence in the electric utility industry.
III. The following interdependent policy principles are intended to guide the New Hampshire public utilities commission in implementing a statewide electric utility industry restructuring plan, in establishing interim stranded cost recovery charges, in approving each utility's compliance filing, in streamlining administrative processes to make regulation more efficient, and in regulating a restructured electric utility industry. In addition, these interdependent principles are intended to guide the New Hampshire general court and the department of environmental services and other state agencies in promoting and regulating a restructured electric utility industry.
374-F:2 Definitions. In this chapter:
I. "Commission" means the public utilities commission.
II. "Electricity suppliers" means suppliers of electricity generation services and includes actual electricity generators and brokers, aggregators, and pools that arrange for the supply of electricity generation to meet retail customer demand, which may be municipal or county entities.
III. "FERC" means the Federal Energy Regulatory Commission.
IV. "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.
374-F:3 Restructuring Policy Principles.
I. System Reliability. Reliable electricity service must be maintained while ensuring public health, safety, and quality of life.
II. Customer Choice. Allowing customers to choose among electricity suppliers will help ensure fully competitive and innovative markets. Customers should be able to choose among options such as levels of service reliability, real time pricing, and generation sources, including interconnected self generation. Customers should expect to be responsible for the consequences of their choices. The commission should ensure that customer confusion will be minimized and customers will be well informed about changes resulting from restructuring and increased customer choice.
III. Regulation and Unbundling of Services and Rates. When customer choice is introduced, services and rates should be unbundled to provide customers clear price information on the cost components of generation, transmission, distribution, and any other ancillary charges. Generation services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services which should remain regulated for the forseeable future. However, distribution service companies should not be absolutely precluded from owning small scale distributed generation resources as part

of a strategy for minimizing transmission and distribution costs. Performance based or incentive regulation should be considered for transmission and distribution services. Upward revaluation of transmission and distribution assets is not a preferred mechanism as part of restructuring. Retail electricity suppliers who do not own transmission and distribution facilities, should, at a minimum, be registered with the commission.

IV. Open Access to Transmission and Distribution Facilities. Non-discriminatory open access to the electric system for wholesale and retail transactions should be promoted. Comparability should be assured for generators competing with affiliates of groups supplying transmission and distribution services. Companies providing transmission services should file at the FERC or with the commission, as appropriate, comparable service tariffs that provide open access for all competitors. The commission should monitor companies providing transmission or distribution services and take necessary measures to ensure that no supplier has an unfair advantage in offering and pricing such services.

V. Universal Service. Electric service is essential and should be available to all customers. A utility providing distribution services must have an obligation to connect all customers in its service territory to the distribution system. A restructured electric utility industry should provide adequate safeguards to assure universal service. Minimum residential customer service safeguards and protections should be maintained. Programs and mechanisms that enable residential customers with low incomes to manage and afford essential electricity requirements should be included as a part of industry restructuring.

VI. Benefits for All Consumers. Restructuring of the electric utility industry should be implemented in a manner that benefits all consumers equitably and does not benefit one customer class to the detriment of another. Costs should not be shifted unfairly among customers. A nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system may be used to fund public benefits related to the provision of electricity. Such benefits, as approved by regulators, may include, but not necessarily be limited to, programs for low-income customers, energy efficiency programs, funding for the electric utility industry's share of commission expenses pursuant to RSA 363-A, support for research and development, and investments in commercialization strategies for new and beneficial technologies.

VII. Full and Fair Competition. Choice for retail customers cannot exist without a range of viable suppliers. The rules that govern market activity should apply to all buyers and sellers in a fair and consistent manner in order to ensure a fully competitive market.

VIII. Environmental Improvement. Continued environmental protection and long term environmental sustainability should be encouraged. Increased competition in the electric industry should be implemented in a manner that supports and furthers the goals of environmental improvement. Over time, there should be more equitable treatment of old and new generation sources with regard to air pollution controls and costs. New Hampshire should encourage equitable and appropriate environmental regulation, based on comparable criteria, for all electricity generators, in and out of state, to reduce air pollution transported across state lines and to promote full, free, and fair competition. As generation becomes deregulated, innovative market-driven approaches are preferred to regulatory controls to reduce adverse environmental impacts. Such market approaches may include valuing the costs of pollution and using pollution offset credits.

IX. Renewable Energy Resources. Increased future commitments to renewable energy resources should be consistent with the New Hampshire energy policy as set forth in RSA 378:37 and should be balanced against the impact on generation prices. Over the long term, increased use of cost-effective renewable energy technologies can have significant environmental, economic, and security benefits. To encourage emerging technologies, restructuring should allow customers the possibility of choosing to pay a premium for electricity from renewable resources and reasonable opportunities to directly invest in and interconnect decentralized renewable electricity generating resources.

X. Energy Efficiency. Restructuring should be designed to reduce market barriers to investments in energy efficiency and provide incentives for appropriate demand-side management and not reduce cost-effective customer conservation. Utility sponsored energy efficiency programs should target cost-effective opportunities that may otherwise be lost due to market barriers.

XI. Near Term Rate Relief. The goal of restructuring is to create competitive markets that are expected to produce lower prices for all customers than would have been paid under the current regulatory system. Given New Hampshire's higher than average regional prices for electricity, utilities, in the near term, should work to reduce rates for all customers. To the greatest extent practicable, rates should approach competitive regional electric rates. The state should recognize when state policies impose costs that conflict with this principle and should take efforts to mitigate those costs. The unique New Hampshire issues contributing to the highest prices

in New England should be addressed during the transition, wherever possible.
XII. Recovery of Stranded Costs.
(a) It is the intent of the legislature to provide appropriate tools and reasonable guidance to the commission in order to assist it in addressing claims for stranded cost recovery and fulfilling its responsibility to determine rates which are equitable, appropriate, and balanced and in the public interest. In making its determinations, the commission shall balance the interests of ratepayers and utilities during and after the restructuring process. Nothing in this section is intended to provide any greater opportunity for stranded cost recovery than is available under applicable regulation or law on the effective date of this chapter.
(b) Utilities should be allowed to recover the net nonmitigatable stranded costs associated with required environmental mandates currently approved for cost recovery, and power acquisitions mandated by federal statutes or RSA 362-A.
(c) Utilities have had and continue to have an obligation to take all reasonable measures to mitigate stranded costs. Mitigation measures may include, but shall not be limited to:
(1) Reduction of expenses.
(2) Renegotiation of existing contracts.
(3) Refinancing of existing debt.
(4) A reasonable amount of retirement, sale, or write-off of uneconomic or surplus assets, including regulatory assets not directly related to the provision of electricity service.
(d) Stranded costs should be determined on a net basis, should be verifiable, should not include transmission and distribution assets, and should be reconciled to actual electricity market conditions from time to time. Any recovery of stranded costs should be through a nonbypassable, nondiscriminatory, appropriately structured charge that is fair to all customer classes, lawful, constitutional, limited in duration, consistent with the promotion of fully competitive markets and consistent with these principles. Entry and exit fees are not preferred recovery mechanisms. Charges to recover stranded costs should only apply to customers within a utility's retail service territory, except for such costs that have resulted from the provision of wholesale power to another utility. The charges should not apply to wheeling-through transactions.
XIII. Regionalism. New England Power Pool (NEPOOL) should be reformed and efforts to enhance competition and to complement industry restructuring on a regional basis should be encouraged. New Hampshire should work with other New England and northeastern states to accomplish the goals of restructuring. Working with other regional states, New Hampshire should assert maximum state authority over the entire electric industry restructuring process. While it is desirable to design and implement a restructured industry in concert with the other New England and northeastern states, New Hampshire should not unnecessarily delay its timetable. Any pool structure adopted for the restructured industry should not preclude bilateral contracts with pool and non-pool services and should not preclude ancillary pool services from being obtained from non-pool sources.
XIV. Administrative Processes. The commission should adapt its administrative processes to make regulation more efficient and to enable competitors to adapt to changes in the market in a timely manner. The market framework for competitive electric service should, to the extent possible, reduce reliance on administrative process. New Hampshire should move deliberately to replace traditional planning mechanisms with market driven choice as the means of supplying resource needs.
XV. Timetable. The commission should seek to implement full customer choice among electricity suppliers in the most expeditious manner possible. The pilot program established in 1995, 272 should be consistent with this pace and not delay implementation of statewide customer choice. The utilities should unbundle rates and services as soon as possible.
374-F:4 Implementation.
I. The commission is authorized to require the implementation of retail choice of electric suppliers for all customer classes of utilities providing retail electric service under its jurisdiction. The commission shall require such implementation no later than January 1, 1998, or at the earliest date determined to be in the public interest by the commission. However, in no event may the implementation be delayed beyond July 1, 1998, without prior legislative approval.
II. Upon the effective date of this chapter, the commission shall undertake a generic proceeding to develop a statewide industry restructuring plan in accordance with the above principles, and shall, after public hearings, issue a final order no later than February 28, 1997. In its order, the commission shall establish the interim stranded cost recovery charge for each electric utility as provided in paragraph VI.
III. The commission shall require all electric utilities subject to its jurisdiction to submit compliance filings,

which shall include open access tariffs and such other information as the commission may require, no later than June 30, 1997. The commission shall investigate and shall approve utility compliance filings, subject to modification by the commission if necessary, after public hearing and subject to a finding that the filings are in the public interest and substantially consistent with the principles established in this chapter.
IV. Notwithstanding the provisions of paragraph I, no utility shall be required to implement its compliance filing resulting from the provisions of this chapter, until compliance filings representing at least 70 percent of retail electric sales (measured in kilowatt hours per year) have been or are being implemented.
V. The commission is authorized to allow utilities to collect a stranded cost recovery charge, subject to its determination in the context of a rate case proceeding that such charge is equitable, appropriate, and balanced, is in the public interest, and is substantially consistent with these interdependent principles. The burden of proof for any stranded cost recovery claim shall be borne by the utility making such claim.
VI.(a) In order to facilitate the rapid transition to full competition, the commission is authorized, in its generic restructuring order as provided in paragraph II, to set, without a formal rate case proceeding, an interim stranded cost recovery charge for each electric utility. Such interim stranded cost recovery charges shall be effective for 2 years from the implementation of utility compliance filings and shall be based on the commission's preliminary determination of an equitable, appropriate, and balanced measure of stranded cost recovery that takes into account the near term rate relief principle, is in the public interest, and is substantially consistent with these interdependent principles. The commission shall also consider the potential for future rate impacts due to possible differences between interim stranded cost recovery charges and charges that may finally be approved for stranded cost recovery.
(b) Any utility may seek adjustment of the interim stranded cost recovery charge at any time based on severe financial hardship, as determined by the commission. The setting of an interim stranded cost recovery charge shall establish no legal, factual, or policy precedent with respect to the final determination of stranded cost recovery by the commission in any subsequent administrative or judicial proceeding.
VII. The interim stranded cost recovery charge established for a utility as provided in paragraph VI may also be adjusted based upon the outcome of rate case proceedings to adjudicate claims for stranded cost recovery pursuant to paragraph V of this section. Any amounts approved by the commission for stranded cost recovery shall be net of amounts previously collected through interim stranded cost recovery charges.
VIII. The commission is authorized to order such charges and other service provisions and to take such other actions that are necessary to implement restructuring and that are substantially consistent with the principles established in this chapter. The commission is authorized to require that distribution and electricity supply services be provided by separate affiliates.
IX. An electricity supplier shall be eligible to compete, subject to necessary limitations established by the commission, for open access customers only if affiliated utilities file comparable open access transmission and distribution rates with the FERC or the commission, or both as appropriate, for all of their transmission facilities in New Hampshire and to the extent practicable, all of their distribution facilities in New Hampshire.
X. Nothing in this chapter shall be construed to prohibit the commission from otherwise exercising its lawful authority under title 34, in proceedings which relate to the introduction of competition in the retail electric utility industry including the retention of experts and consultants to assist the commission in its investigations and the assessment of such costs against utilities and any other parties to the proceedings, consistent with RSA 365:37 and RSA 365:38.
XI. Any administrative or adjudicative proceeding or public hearing relating to this chapter shall be subject to the provisions of RSA 541-A.
374-F:5 Oversight Committee; Establishment; Report; Meetings.
I. There is established a legislative oversight committee on electric utility restructuring consisting of 14 members as follows:
(a) Seven members of the house, at least 5 of whom shall be members of the science, technology and energy committee, or its successor, and at least 2 of whom shall be members of a minority party, appointed by the speaker of the house.
(b) Seven members of the senate, at least 2 of whom shall be members of the executive departments and administration committee, or its successor, and at least one of whom shall be a member of the minority party, appointed by the president of the senate.
II.(a) Committee members shall be appointed to an initial term expiring on December 4, 1996. Subsequent terms shall be for up to 2 years expiring on the first Wednesday of even-numbered years. Members may succeed

themselves.
(b) A chairperson shall be selected by a majority of the committee members.
III. The committee shall provide an annual report on or before November 1 to the governor, the speaker of the house, the senate president, the state library, and the public utilities commission on the status of electric utility restructuring.
IV. The committee shall meet quarterly or as often as is necessary to conduct its business.
V. Members shall receive mileage when attending to the duties of the committee.
374-F:6 Duties. The committee shall be responsible for the following:
I. Following up the work of the retail wheeling and restructuring study committee established in 1995, 272.
II. Working with the commission to assess the results of the pilot program allowing for the competitive retail purchase of electricity established in 1995, 272.
III. Working with the commission to develop any new legislation necessary to promote electric utility restructuring and retail choice of electricity suppliers and to propose changes to or recodification of existing statutes to be more consistent with the restructuring principles established in this chapter.
IV. Working with the commission and other agencies, where necessary, to implement this chapter and its restructuring principles.
129:3 Adjudication. If any party challenges any provision of RSA 374-F as inserted by section 2 of this act or any application thereof in court, then the general court urges the court of jurisdiction to give priority to and expeditiously adjudicate any such challenge.
129:4 Severability. If any provision of this act or the application thereof to any person or circumstances is held invalid, the invalidity does not affect other provisions or applications of the act which can be given effect without the invalid provisions or applications, and to this end the provisions of this act are severable.
129:5 Effective Date. This act shall take effect upon its passage.

Approved: May 21, 1996
Effective: May 21, 1996

TITLE I
THE STATE AND ITS GOVERNMENT

CHAPTER 4-E
STATE ENERGY STRATEGY

Section 4-E:1

4-E:1 State Energy Strategy. –
I. The office of energy planning, in consultation with the state energy advisory council established in RSA 4-E:2, with assistance from an independent consultant and with input from the public and interested parties, shall prepare a 10-year energy strategy for the state. The office shall review the strategy and consider any necessary updates in consultation with the senate energy and natural resources committee and the house science, technology and energy committee, after opportunity for public comment, at least every 3 years starting in 2017. The state energy strategy shall include, but not be limited to, sections on the following:
(a) The projected demand for consumption of electricity, natural gas, and other fuels for heating and other related uses.
(b) Existing and proposed electricity and natural gas generation and transmission facilities, the effects of future retirements and new resources, and consideration of possible alternatives.
(c) Renewable energy and fuel diversity.
(d) Small-scale and distributed energy resources, energy storage technologies, and their potential in the state.
(e) The role of energy efficiency, demand response, and other demand-side resources in meeting the state's energy needs.
(f) The processes for siting energy facilities in the state and the criteria used by the site evaluation committee in giving adequate consideration to the protection of the state's ecosystems and visual, historic, and aesthetic resources in siting processes.
(g) The relationship between land use and transportation policies and programs on electricity and thermal energy needs in the state.
(h) New Hampshire's role in the regional electric markets, how the regional market affects the state's energy policy goals, and how the state can most effectively participate at the regional level.
II. The strategy shall include a review of all state policies related to energy, including the issues in paragraph I, and recommendations for policy changes and priorities necessary to ensure the reliability, safety, fuel diversity, and affordability of New Hampshire's energy sources, while protecting natural, historic, and aesthetic resources and encouraging local and renewable energy resources. The strategy shall also include consideration of the extent to which demand-side measures including efficiency, conservation, demand response, and load management can cost-effectively meet the state's energy needs, and proposals to increase the use of such demand resources to reduce energy costs and increase economic benefits to the state.
III. The strategy development process shall include review and consideration of relevant studies and plans, including but not limited to those developed by the independent system operator of New England (ISO-NE), the public utilities commission, the energy efficiency and sustainable energy board, legislative study committees and commissions, and other state and regional organizations as appropriate. The strategy shall also include consideration of new technologies and their potential impact on the state's energy future.

Source. 2013, 276:3, eff. July 24, 2013.

Section 4-E:2-5

4-E:2 to 4-E:5 Repealed. – [Repealed 2013, 276:5, eff. Dec. 31, 2014.]

TITLE I
THE STATE AND ITS GOVERNMENT

CHAPTER 21
STATUTORY CONSTRUCTION

Section 21:2

21:2 Common Usage. – Words and phrases shall be construed according to the common and approved usage of the language; but technical words and phrases, and such others as may have acquired a peculiar and appropriate meaning in law, shall be construed and understood according to such peculiar and appropriate meaning.

Source. GS 1:2. GL 1:2. PS 2:2. PL 2:2. RL 7:2.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 362
DEFINITION OF TERMS; UTILITIES EXEMPTED

Section 362:4

362:4 Water Companies, When Public Utilities. –

I. Every corporation, company, association, joint stock association, partnership, or person shall be deemed to be a public utility by reason of the ownership or operation of any water or sewage disposal system or part thereof. If the whole of such water or sewage disposal system shall supply a less number of consumers than 75, each family, tenement, store, or other establishment being considered a single consumer, the commission may exempt any such water or sewer company from any and all provisions of this title whenever the commission may find such exemption consistent with the public good.

II. A municipal corporation furnishing water or sewage disposal services outside its municipal boundaries shall not be considered a public utility under this title for the purpose of accounting, reporting, or auditing functions with respect to said service.

III. A municipal corporation furnishing sewage disposal services shall not be considered a public utility under this title:

(a) If it serves customers outside its municipal boundaries, charging such customers a rate no higher than that charged to its customers within the municipality, and serves those customers a level of sewage disposal service equal to that served to customers within the municipality. Nothing in this section shall exempt a municipal corporation from the franchise application requirements of RSA 374.

(b) If it supplies bulk sewage disposal services pursuant to a wholesale rate or contract to another municipality, village district, or water precinct.

III-a. (a) A municipal corporation furnishing water services shall not be considered a public utility under this title:

(1) If it serves new customers outside its municipal boundaries, charging such customers a rate no higher than 15 percent above that charged to its municipal customers, including current per-household debt service costs for water system improvements, within the municipality, and serves those customers a quantity and quality of water or a level of water service equal to that served to customers within the municipality. Nothing in this paragraph shall exempt a municipal corporation from the franchise application requirements of RSA 374.

(2) If it supplies bulk water pursuant to a wholesale rate or contract to another municipality, village district, or water precinct. This subparagraph shall not apply to bulk water contracts which were in effect before July 23, 1989, or to the renewal of said bulk water contracts.

(b) The commission may exempt a municipal corporation from any and all provisions of this title except the franchise application requirements of RSA 374, and may authorize a municipal corporation to charge new customers outside its municipal boundaries a rate higher than 15 percent above that charged to its municipal customers, if after notice and hearing, the commission finds such exemption and authorization to be consistent with the public good. The commission may not authorize a municipal corporation to charge existing customers outside its municipal boundaries a rate higher than 15 percent above that charged to its municipal customers until any rate agreements in effect for those customers on May 13, 2002 shall have expired.

(c) A municipal corporation's authority to charge higher rates for new customers outside of its municipal boundaries shall be applied prospectively to new customers taking water service provided by means of a main extension or an expansion of the municipal corporation's system after the effective date of this paragraph.

(d) A municipal corporation's authority to charge higher rates for existing customers outside of its municipal boundaries shall not become effective until any rate agreements in effect on May 13, 2002 have expired.

(e) A municipal corporation serving customers outside of its municipal boundaries and charging a rate no higher than 15 percent above that charged to its municipal customers prior to July 1, 2002, may also be exempted from regulation as a public utility, except for the franchise application requirements of RSA 374, if after notice and hearing, the commission finds such exemption and authorization to be consistent with the public good.

IV. (a) Any customer of a water utility shall have the right to terminate water service and secure water from an alternate source, if the customer can demonstrate the ability to comply with the requirements of RSA 485-A:29 and RSA 485-A:30-b, and the administrative rules adopted to implement these sections.

(b) Any covenant in a deed or contract that restricts the right to terminate water service from a water utility or in any way limits that right, shall be void as against public policy.

V. No property owner shall be required to connect to a municipal corporation furnishing water, provided such property owner can demonstrate the ability to comply with the requirements of RSA 485-A:29 and RSA 485-A:30-b.

VI. (a) For purposes of this chapter, a municipal corporation shall include a regional water district.

(b) During the initial 4 years of its operation, if a regional water district seeks to alter rates other than in a manner that uniformly impacts all customers within the district, any municipality that is a member of the regional water district may seek commission review of the proposed rate change. In order for the proposed rate change to take effect, the commission must determine that the proposed rates are cost-based and that they are not unduly discriminatory.

(c) A regional water district shall adopt and enforce quality of water service standards consistent with the commission's administrative rules.

(d) With respect to regional water districts, the 15 percent benchmark employed in this section shall be calculated in relation to an average of the regional water district's relevant rates as determined by the public utilities commission.

VII. (a) A homeowners association, including but not limited to a condominium unit owners association, shall not be considered a public utility under this title by virtue of providing water service if:

(1) The service is furnished only to members of the association or the occupants of their residential units; and

(2) The association is organized on a not-for-profit basis and is democratically controlled by the owners of the residential units and not the developer or subdivider thereof.

(b) Such a homeowners association is one consumer for purposes of paragraph I, and its individual members or their lessees shall not be treated as individual consumers.

Source. 1913, 145:1. 1917, 76:1. PL 236:5. RL 285:5. 1951, 203:9 par. 4. RSA 362:4. 1957, 33:1. 1971, 333:1. 1973, 546:1. 1988, 134:1. 1989, 240:1. 1992, 170:1. 1993, 248:1. 2001, 237:2. 2002, 141:4, 52; 174:3. 2003, 178:15; 281:12. 2007, 25:2, eff. May 11, 2007.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 362-A
LIMITED ELECTRICAL ENERGY PRODUCERS ACT

Section 362-A:1

362-A:1 Declaration of Purpose. – It is found to be in the public interest to provide for small scale and diversified sources of supplemental electrical power to lessen the state's dependence upon other sources which may, from time to time, be uncertain. It is also found to be in the public interest to encourage and support diversified electrical production that uses indigenous and renewable fuels and has beneficial impacts on the environment and public health. It is also found that these goals should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3. It is further found that net energy metering for eligible customer-generators may be one way to provide a reasonable opportunity for small customers to choose interconnected self generation, encourage private investment in renewable energy resources, stimulate in-state commercialization of innovative and beneficial new technology, enhance the future diversification of the state's energy resource mix, and reduce interconnection and administrative costs.

Source. 1978, 32:1. 1994, 362:2. 1998, 261:1, eff. Aug. 25, 1998. 2010, 143:1, eff. Aug. 13, 2010.

Section 362-A:1-a

362-A:1-a Definitions. – In this chapter:

I. "Bio-oil" means a liquid renewable fuel derived from vegetable oils, animal fats, wood, straw, forestry byproducts, or agricultural byproducts using noncombustion thermal, chemical, or biological processes, including, but not limited to, distillation, gasification, hydrolysis, or pyrolysis, but not including anaerobic digestion, composting, or incineration.

I-a. "Bio synthetic gas" means a gaseous renewable fuel derived from vegetable oils, animal fats, wood, straw, forestry byproducts, or agricultural byproducts using noncombustion thermal, chemical, or biological processes, including, but not limited to, distillation, gasification, hydrolysis, or pyrolysis, but not including anaerobic digestion, composting, or incineration.

I-b. "Biodiesel" means a renewable diesel fuel substitute that is composed of mono-alkyl esters of long chain fatty acids, is derived from vegetable oils or animal fats, and meets the requirements of the American Society for Testing and Materials (ASTM) specification D6751.

I-c. "Cogeneration facility" means a facility which produces electric energy and other forms of useful energy, such as steam or heat, which are used for industrial, commercial, heating, or cooling purposes.

I-d. "Combined heat and power system" means a new system installed after July 1, 2011, that produces heat and electricity from one fuel input using an eligible fuel, without restriction to generating technology, has an electric generating capacity rating of at least one kilowatt and not more than 30 kilowatts and a fuel system efficiency of not less than 80 percent in the production of heat and electricity, or has an electric generating capacity greater than 30 kilowatts and not more than one megawatt and a fuel system efficiency of not less than 65 percent in the production of heat and electricity. Fuel system efficiency shall be measured as usable thermal and electrical output in BTUs divided by fuel input in BTUs.

II. "Commission" means the New Hampshire public utilities commission.

II-a. "Electricity suppliers" has the same meaning as in RSA 374-F:2, II.

II-b. "Eligible customer-generator" or "customer-generator" means an electric utility customer who owns, operates, or purchases power from an electrical generating facility either powered by renewable energy or which employs a heat led combined heat and power system, with a total peak generating capacity of up to and including one megawatt, that is located behind a retail meter on the customer's premises, is interconnected and operates in parallel with the electric grid, and is used to offset the customer's own electricity requirements. Incremental generation added to an existing generation facility, that does not itself qualify for net metering, shall qualify if such incremental generation meets the qualifications of this paragraph and is metered separately from the nonqualifying facility.

II-c. "Eligible fuel" means natural gas, propane, wood pellets, hydrogen, or heating oil when combusted with a burner, including air emission standards for the device using the approved fuel.

II-d. "Heat led" means that the combined heat and power system is operated in a manner to satisfy the heat usage needs of the customer-generator.

III. "Limited producer" or "limited electrical energy producer" means a qualifying small power producer or a qualifying cogenerator, with a total capacity of not more than 5 megawatts.

III-a. "Net energy metering" means measuring the difference between the electricity supplied over the electric distribution system and the electricity generated by an eligible customer-generator which is fed back into the electric distribution system over a billing period.

IV. "Person" means any individual, partnership, association, corporation, governmental unit or agency or any combination thereof.

V. "Primary energy source" means the fuel or fuels used for the generation of electric energy, except that such term does not include the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, or control uses or the minimum amounts of fuel required to alleviate or prevent unanticipated equipment outages or emergencies directly affecting the public health, safety or welfare which would result from electric power outages.

VI. "Qualifying cogeneration facility" means a cogeneration facility which the commission determines meets such requirements, including requirements respecting minimum size, fuel use and fuel efficiency, as the commission may prescribe and which is owned by a person not primarily engaged in the generation or sale of electric power, other than electric power solely from cogeneration facilities or small power production facilities.

VII. "Qualifying cogenerator" means the owner or operator of a qualifying cogeneration facility.

VII-a. "Qualifying facility" means either or both of a qualifying small power production facility or qualifying cogeneration facility.

VIII. "Qualifying small power producer" means the owner or operator of a qualifying small power production facility.

IX. "Qualifying small power production facility" means a small power production facility which the commission determines meets such requirements, including requirements respecting fuel use, fuel efficiency and reliability, as the commission may prescribe and which is owned by a person not primarily engaged in the generation or sale of electric power, other than electric power solely from cogeneration facilities or small power production facilities.

X. "Small power production facility" means a facility which produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, bio-oil, bio synthetic gas, biodiesel, or any combination thereof and which has a power production capacity which, together with any other facility located at the same site, as determined by the commission, is not greater than 30 megawatts.

Source. 1983, 395:1. 1989, 211:1. 1998, 261:2-4. 2006, 294:1, 2. 2007, 174:1, eff. Aug. 17, 2007. 2010, 143:2, eff. Aug. 13, 2010. 2011, 168:1, 2, eff. July 1, 2011. 2013, 266:1, eff. July 24, 2013. 2014, 130:2, eff. Aug. 15, 2014.

Section 362-A:2

362-A:2 Exemptions. – Qualifying small power producers and qualifying cogenerators shall be exempt from all rules and statutes relative to electric utility rates or relative to the financial or organizational regulation of electric utilities.

Source. 1978, 32:1. 1983, 395:2, eff. Aug. 21, 1983.

Section 362-A:2-a

362-A:2-a Purchase of Output by Private Sector. –

I. A limited producer of electrical energy shall have the authority to sell its produced electrical energy to not more than 3 purchasers other than the franchise electric utility, unless additional authority to sell is otherwise allowed by statute or commission order. Such purchaser may be any individual, partnership, corporation, or association. The commission may authorize a limited producer, including eligible customer-generators, to sell electricity at retail, either directly or indirectly through an electricity supplier, within a limited geographic area where the purchasers of electricity from the limited producer shall not be charged a transmission tariff or rate for such sales if transmission facilities or capacity under federal jurisdiction are not used or needed for the transaction. The public utilities commission shall review and approve all contracts concerning a retail sale of electricity pursuant to this section. The public utilities commission shall not set the terms of such contracts but may disapprove any contract which in its judgment:

(a) Fails to protect both parties against excessive liability or undue risk, or

(b) Entails substantial cost or risk to the electric utility in whose franchise area the sale takes place, or

(c) Is inconsistent with the public good.

II. Upon request of a limited producer, any franchised electrical public utility in the transmission area shall transmit electrical energy from the producer's facility to the purchaser's facility in accordance with the provisions of this section. The producer shall compensate the transmitter for all costs incurred in wheeling and delivering the current to the purchaser. The public utilities commission must approve all such agreements for the wheeling of power and retains the right to order such wheeling and to set such terms for a wheeling agreement including price that it deems necessary. The public utilities commission or any party involved in a wheeling transaction may demand a full hearing before the commission for the review of any and all of the terms of a wheeling agreement.

III. Before ordering an electric utility to wheel power from a limited electric producer or before approving any agreement for the wheeling of power, the public utilities commission must find that such an order or agreement:

(a) Is not likely to result in a reasonably ascertainable uncompensated loss for any party affected by the wheeling transaction.

(b) Will not place an undue burden on any party affected by the wheeling transaction.

(c) Will not unreasonably impair the reliability of the electric utility wheeling the power.

(d) Will not impair the ability of the franchised electric utility wheeling the power to render adequate service to its customers.

Source. 1979, 411:1. 1998, 261:5, eff. Aug. 25, 1998.

Section 362-A:3

362-A:3 Purchase of Output of Limited Electrical Energy Producers by Public Utilities. –

I. The entire output of electric energy of such limited electrical energy producers, if offered for sale to the electric utility, shall be purchased by the electric public utility which serves the franchise area in which the installations of such producers are located.

II. No purchases and related transactions involving qualifying facilities shall take place under RSA 362-A:3 or RSA 362-A:4 in any location where retail electric competition is certified to exist pursuant to RSA 38:36, unless such purchase or related transaction is pursuant to:

(a) Commission orders or agreements providing for qualifying facility power sales existing prior to such certification;

(b) Negotiated qualifying facility power purchase contracts existing prior to such certification; or

(c) Commission orders or agreements resulting from the renegotiation of orders, agreements, or contracts referenced in subparagraphs (a) and (b).

Source. 1978, 32:1. 1979, 411:2. 1983, 395:3. 1998, 261:6, eff. Aug. 25, 1998.

Section 362-A:4

362-A:4 Payment by Public Utilities for Purchase of Output. – Public utilities purchasing electrical energy in accordance with the provisions of this chapter shall pay rates per kilowatt hour to be set from time to time by the commission. Such rates shall be based on the purchasing utility's avoided costs. The commission may set long term rates which shall, at the option of the qualifying small power producer or qualifying cogenerator, be based on the purchasing utility's avoided costs either calculated for the time of delivery or calculated for a specified term at the time the qualifying small power producer or qualifying cogenerator agrees to be obligated to deliver for the specified term. Nothing in this section shall limit the authority of any electric utility or any qualifying small power producer or qualifying cogenerator to agree to a rate for any purchase which differs from the rate or terms or conditions which would otherwise be required by the commission. No payments or rates shall be required by this section in locations where retail electric competition is certified to exist pursuant to RSA 38:36, unless such payments or rates are pursuant to an arrangement authorized by RSA 362-A:3.

Source. 1978, 32:1. 1983, 395:4. 1998, 261:7, eff. Aug. 25, 1998.

Section 362-A:4-a

362-A:4-a Additions to Capacity of Small Power Production Facilities. – Any qualifying small power production facility already subject to rates established by order of the commission may increase its capacity and energy or energy, provided it continues to be a small power production facility. Any capacity additions and the associated energy additions or the energy additions to such qualifying small power production facility shall be purchased in accordance with applicable law and may be purchased under a contract. Such capacity addition and associated energy additions or energy additions shall not be purchased under the rates established by existing orders of the commission. Such rates and orders shall otherwise remain applicable to the qualifying small power production facility.

Source. 1989, 211:2, eff. July 21, 1989.

Section 362-A:4-b

362-A:4-b Buyout of Existing Rate Orders. – [Repealed 1998, 261:15, eff. Aug. 25, 1998.]

Section 362-A:4-c

362-A:4-c Consideration by the Commission. –

I. The commission shall independently and expeditiously consider any mutually acceptable agreement for the buydown, buyout, or renegotiation of any existing commission order providing for qualifying facility power sales or power purchase agreement regardless of the status of any other such pending renegotiations.

II. The commission shall not approve any buyout of a listed facility prior to July 1, 2000. The commission shall not approve any buyout of a listed facility until competition is certified to exist in at least 70 percent of the state pursuant to RSA 38:36.

III. The commission shall not approve any renegotiation which places restrictions on selling the output of the qualifying facility in a competitive generation market pursuant to RSA 374-F.

IV. The commission shall not approve any renegotiation of a commission order providing for power sales from a listed facility if, for any calendar year prior to 2006, that renegotiation would reduce the total number of kilowatt hours being purchased annually at predetermined prices from all listed facilities to less than 80 percent of the base listed-facility kilowatt hours for that calendar year.

V. In this section:

(a) "Base listed-facility kilowatt hours for that calendar year" means the total number of kilowatt hours which would have been purchased during the calendar year from all listed facilities if the renegotiated rate orders for all such listed facilities pending before the commission as of January 1, 1998 had been approved.

(b) "Buyout" means any modification of any existing commission order providing for power sales from a listed facility that (i) changes the termination date of that order to an earlier date, unless the modified termination date is not earlier than the termination date in the renegotiated buydown for that listed facility which was pending before the commission as of January 1, 1998, or (ii) eliminates predetermined prices for any of the output of the facility covered by the rate order.

(c) "Listed facility" means any of the 5 wood-fired qualifying facilities having rate orders which, as of January 1, 1998, provide the right to sell at least 10 megawatts of capacity and associated energy to Public Service Company of New Hampshire.

Source. 1994, 362:13. 1998, 261:8, eff. Aug. 25, 1998.

Section 362-A:4-d

362-A:4-d Retention of Savings by Electric Utility. – An electric utility that is party to an approved renegotiation of a commission order under RSA 362-A:4-c shall be entitled to retain 20 percent of the savings resulting from such renegotiation.

Source. 2000, 249:1. 2001, 29:8, eff. May 22, 2001.

Section 362-A:5

362-A:5 Settlement of Disputes. – Any dispute arising under the provisions of this chapter may be referred by any party to the commission for adjudication.

Source. 1978, 32:1. 1983, 395:4, eff. Aug. 21, 1983.

Section 362-A:6

362-A:6 Tax Exemption for Qualifying Small Power Production Facilities and Qualifying Cogeneration Facilities. – [Repealed 1997, 294:3, eff. March 1, 1997.]

Section 362-A:6-a

362-A:6-a Payment in Lieu of Tax Agreements for Renewable Generation Facilities. – The owner, or a lessee responsible for payment of taxes, of a renewable generation facility and the municipality in which the facility is located may enter into a voluntary agreement to make a payment in lieu of taxes, pursuant to RSA 72:74.

Source. 2006, 294:7, eff. April 1, 2006.

Section 362-A:7

362-A:7 Hydroelectric Fund Authorized. – Any town or city may establish a hydroelectric fund to hold a portion of the revenue received from its hydroelectric plant. The hydroelectric fund may be established by a majority vote at an annual or special town meeting or majority vote of the city council. If established, the town or city treasurer shall have custody of the hydroelectric fund, and shall pay out the same upon orders of the selectmen or city council, after the specified sum to be withdrawn has been authorized by a majority vote at an annual or special town meeting or majority vote of the city council. Money from this fund may be used for any purpose for which the town or city may appropriate money.

Source. 1985, 145:1, eff. May 20, 1985.

Section 362-A:8

362-A:8 Payment Obligations; Public Utilities. –

I. The purpose of this section is to codify existing law on regulatory obligations of public utilities for the purchase, pursuant to applicable federal and state law and commission orders, of energy or energy and capacity from qualifying small power producers and qualifying cogenerators.

II. (a) Energy or energy and capacity provided by qualifying small power producers and qualifying cogenerators under commission orders or negotiated power purchase contracts are part of the energy mix relied on by the commission to serve the present and future energy needs of the state. The rates established in orders by the commission for the purchase of energy or energy and capacity from qualifying small power producers and qualifying cogenerators under this chapter or under applicable federal law exist under the legislative and regulatory authority of the state and shall be deemed a state approved legally enforceable obligation.

(b) The commission shall, in all decisions affecting qualifying small power producers and qualifying cogenerators, consider the following factors in its decisions:

(1) The economic impact upon the state, including, but not limited to, job loss or creation through the utilization of indigenous fuels for electric generation.

(2) The community impact including, but not limited to, property tax payments and job creation.

(3) Enhanced energy security by utilizing mixed energy sources, including indigenous and renewable electrical energy production.

(4) Potential environmental and health-related impacts.

(5) The impact on electric rates.

III. The invalidity of any part of this section shall not destroy the section as a whole if its general purpose can be accomplished, notwithstanding any such invalidity.

Source. 1988, 174:1. 1994, 362:3. 1998, 261:9, eff. Aug. 25, 1998.

Section 362-A:9

362-A:9 Net Energy Metering. –

I. Standard tariffs providing for net energy metering shall be made available to eligible customer-generators by each electric distribution utility in conformance with net metering rules adopted and orders issued by the commission. Each net energy metering tariff shall be identical, with respect to rates, rate structure, and charges, to the tariff under which a customer-generator would otherwise take default generation supply service from the distribution utility. Such tariffs shall be available on a first-come, first-served basis within each electric utility service area under the jurisdiction of the commission until such time as the total rated generating capacity owned or operated by eligible customer-generators totals a number equal to 100 megawatts, with 50 megawatts of the 100 megawatts allocated to the 4 electric distribution utilities that were subject to the commission's jurisdiction in 2010 multiplied by each such utility's percentage share of the total 2010 annual coincident peak energy demand distributed by those 4 utilities, and 50 megawatts of the 100 megawatts allocated to the state's 3 investor-owned electric distribution utilities, multiplied by each such utility's percentage share of the total 2010 annual coincident peak energy demand distributed by those 3 utilities, all to be determined by the commission and to be utilized by eligible customer-generators located within each such utilities' service territory. Eighty percent of each utility's share of the 50 megawatts shall be apportioned to facilities with a total generating capacity of not more than 100 kilowatts and 20 percent to facilities with a total generating capacity in excess of 100 kilowatts, but no greater than one megawatt. The 50 megawatts of capacity shall be made available to eligible customer-generators until such time as commission approved alternative net metering tariffs approved by the commission become available. No more than 4 megawatts of such total rated generating capacity shall be from a combined heat and power system as defined in RSA 362-A:1-a, I-d.

[Paragraph I-a repealed by 2016, 33:3 effective as provided by 2016, 33:4.]

I-a. No person, owner, developer, installer of an eligible customer-generator facility, business organization, or any subsidiary thereof, shall reserve capacity space in the net metering interconnection queue of more than 20 percent of the total net metering utility-specific allocation pursuant to this section, and the creation of multiple business organizations, including a person, as defined in RSA 366:1, I, by the same shall not defeat this requirement. On a weekly basis each utility shall make public on its website its total net metering allocation, its reserved net metering capacity, and its installed and operating net metering capacity. For project applications of greater than 100 kilowatts, each utility net metering interconnection queue application shall include a certification of compliance with the 20 percent requirement, all persons involved in such an application shall sign the certification of compliance, and no application shall be processed where one or more persons involved in the application did not sign the certification of compliance.

II. Competitive electricity suppliers registered under RSA 374-F:7 may determine the terms, conditions, and prices under which they agree to provide generation supply to and purchase net generation output from eligible customer-generators.

III. Metering shall be done in accordance with normal metering practices. A single net meter that shows the customer's net energy usage by measuring both the inflow and outflow of electricity internally shall be the extent of metering that is required at facilities with a total peak generating capacity of not more than 100 kilowatts. A bi-directional metering system that records the total amount of electricity that flows in each direction from the customer premises, either instantaneously or over intervals of an hour or less, shall be required at facilities with a total peak generating capacity of more than 100 kilowatts. Customer-generators shall not be required to pay for the installation of net meters, but shall pay for the installation of all bi-directional metering systems as outlined in utility interconnection tariffs or rules.

IV. (a) For facilities with a total peak generating capacity of not more than 100 kilowatts, when billing a customer-generator under a net energy metering tariff that is not time-based, the utility shall apply the customer's net energy usage when calculating all charges that are based on kilowatt hour usage. Customer net energy usage shall equal the kilowatt hours supplied to the customer over the electric distribution system minus the kilowatt hours generated by the customer-generator and fed into the electric distribution system over a billing period.

(b) For facilities with a total peak generating capacity of more than 100 kilowatts, the customer-generator shall pay all applicable charges on all kilowatt hours supplied to the customer over the electric distribution system, less a credit on default service charges equal to the metered energy generated by the customer-generator and fed into the electric distribution system over a billing period.

V. When a customer-generator's net energy usage is negative (more electricity is fed into the distribution system than is received) over a billing period, such surplus shall either:

(a) Be credited to the customer-generator's account on an equivalent basis for use in subsequent billing cycles as a credit against the customer's net energy usage or bill in a manner consistent with either subparagraph IV(a) or IV(b), as applicable; or

(b) Except as provided in paragraph VI, the customer-generator may elect to be paid or credited by the electric distribution utility for its excess generation at rates that are equal to the utility's avoided costs for energy and capacity to provide default service as determined by the commission consistent with the requirements of the Public Utilities Regulatory Policy Act of 1978 (PURPA). The commission shall determine reasonable conditions for such an election, including the frequency of payment and how often a customer-generator may choose this option versus the option in subparagraph (a).

VI. Instead of the option in subparagraph V(b), an electric distribution utility providing default service to customer-generators may voluntarily elect, annually, on a generic basis, by notification to the commission, to purchase or credit such excess generation from customer-generators at a rate that is equal to the generation supply component of the applicable default service rate, provided that payment is issued at least as often as whenever the value of such credit, in excess of amounts owed by the customer-generator, is greater than $50.

VII. A distribution utility may perform an annual calculation to determine the net effect this section had on its default service and distribution revenues and expenses in the prior calendar year. The method of performing the calculation and applying the results, as well as a reconciliation mechanism to collect or credit any such net effects with appropriate carrying charges and credits applied, shall be determined by the commission.

VIII. Notwithstanding other provisions of this section, the commission may establish, on a utility-specific or generic basis, a methodology by which customer-generators may be provided service under time-based, net energy metering tariffs. The methodology shall specify how a customer's energy usage and generation shall be metered, how net energy usage shall be calculated and any applicable charges applied, and how excess generation shall be credited, consistent with size limits and the terms and conditions and intent of this section and other requirements of state and federal law.

IX. Renewable energy credits shall remain the property of the customer-generator until such credits are sold or transferred. If an electric distribution utility acquires renewable energy credits from a customer-generator in conjunction with purchasing excess generation, it may apply such generation and credits to its renewable energy source default service option under RSA 374-F:3, V(f).

X. The commission shall adopt rules, pursuant to RSA 541-A, to:

(a) Establish reasonable interconnection requirements for safety, reliability, and power quality as it determines the public interest requires. Such rules shall not exceed applicable test standards of the American National Standards Institute (ANSI) or Underwriters Laboratory (UL); and

(b) Implement the provisions of this section.

XI. The commission may by order, after notice and hearing:

(a) Waive any of the limitations set forth in this chapter for targeted net energy metering arrangements that are part of a utility strategy to minimize distribution or other costs; and

(b) Implement any utility-specific provisions authorized under this section.

XII. Once the commission has established standards for equipment used by eligible customer-generators, electric distribution utilities shall not require any additional standards or testing for transmission equipment as a condition of net energy metering.

XIII. Customer-generators shall be responsible for all costs associated with interconnection with the distribution system.

XIV. (a) A customer-generator may elect to become a group host for the purpose of reducing or otherwise controlling the energy costs of a group of customers who are not customer-generators. The group of customers shall be default service customers of the same electric distribution utility as the host. The host shall provide a list of the group members to the commission and the electric distribution utility and shall certify that all members of the group have executed an agreement with the host regarding the utilization of kilowatt hours produced by the eligible facility and that the total historic annual load of the group members together with the host exceeds the projected annual output of the host's facility. The commission shall verify that these group requirements have been met, shall review the executed agreements for compliance with this section, and shall register the group host. The commission shall establish the process for registering hosts, including periodic re-registration, and the process by which changes in membership are allowed and administered. Net metering tariffs under this section shall not be made available to a customer-generator group host until such host is registered by the commission.

(b) Except as provided in subparagraph (c), the provisions of this section shall apply to a group host as a customer-generator.

(c) Notwithstanding paragraph V, a group host shall be paid for its surplus generation at the end of each billing cycle at rates consistent with the credit the group host receives relative to its own net metering under either subparagraph IV(a) or (b) or alternative tariffs that may be applicable pursuant to paragraph XVI. On an annual basis, the electric distribution utility shall calculate a payment adjustment if the host's surplus generation for which it was paid is greater than the group's total electricity usage during the same time period. The adjustment shall be such that the resulting compensation to the host for the amount that exceeded the group's total usage shall be at the utility's avoided cost or its default service rate in accordance with subparagraph V(b) or paragraph VI or alternative tariffs that may be applicable pursuant to paragraph XVI. The utility shall pay or bill the host accordingly.

(d) Group hosts shall be responsible for any costs necessary to upgrade a utility's information systems in order to implement this paragraph, as determined by the commission.

(e) The commission is authorized to assess fines against, revoke the registration of, and prohibit from doing business in the state, any group host which violates the requirements of this paragraph and rules adopted pursuant to this paragraph.

XV. Standard tariffs that are available to eligible customer-generators under this section shall terminate on December 31, 2040 and such customer-generators shall transition to tariffs that are in effect at that time.

XVI. No later than 3 weeks after the effective date of this paragraph, the commission shall initiate a proceeding to develop new alternative net metering tariffs, which may include other regulatory mechanisms and tariffs for customer-generators, and determine whether and to what extent such tariffs should be limited in their availability within each electric distribution utility's service territory. In developing such alternative tariffs and any limitations in their availability, the commission shall consider: the costs and benefits of customer-generator facilities; an avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time based tariffs pursuant to paragraph VIII; whether there should be a limitation on the amount of generating capacity eligible for such tariffs; the size of facilities eligible to receive net metering tariffs: timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms. The commission may waive or modify specific size limits and terms and conditions of service for net metering specified in paragraphs I, III, IV, V, and VI that it finds to be just and reasonable in the adoption of alternative tariffs for customer-generators. The commission may approve time and/or size limited pilots of alternative tariffs.

XVII. The commission shall issue an order initially approving or adopting such alternative tariffs, which may be subject to change or adjustment from time to time, within 10 months of the effective date of this paragraph.

XVIII. If any utility reaches any cap for net metering under paragraph I before alternative tariffs are approved or adopted pursuant to paragraph XVII, eligible customer-generators may continue to interconnect under temporary net metering tariffs under the same terms and conditions as net metering under the 100 megawatt cap, except that such customer-generators shall transition to alternative tariffs once they are approved or adopted for their utility pursuant to paragraph XVII.

Source. 1998, 261:10. 2000, 148:1, 2. 2007, 174:2-4, eff. Aug. 17, 2007. 2010, 143:3, eff. Aug. 13, 2010. 2011, 168:3, eff. July 1, 2011. 2012, 59:1, eff. July 13, 2012. 2013, 266:2, eff. July 24, 2013. 2016, 31:3-5; 33:1-3, eff. May 2, 2016.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 362-F
ELECTRIC RENEWABLE PORTFOLIO STANDARD

Section 362-F:1

362-F:1 Purpose. – Renewable energy generation technologies can provide fuel diversity to the state and New England generation supply through use of local renewable fuels and resources that serve to displace and thereby lower regional dependence on fossil fuels. This has the potential to lower and stabilize future energy costs by reducing exposure to rising and volatile fossil fuel prices. The use of renewable energy technologies and fuels can also help to keep energy and investment dollars in the state to benefit our own economy. In addition, employing low emission forms of such technologies can reduce the amount of greenhouse gases, nitrogen oxides, and particulate matter emissions transported into New Hampshire and also generated in the state, thereby improving air quality and public health, and mitigating against the risks of climate change. It is therefore in the public interest to stimulate investment in low emission renewable energy generation technologies in New England and, in particular, New Hampshire, whether at new or existing facilities.

Source. 2007, 26:2, eff. July 10, 2007.

Section 362-F:2

362-F:2 Definitions. – In this chapter:

I. "Begun operation" means the date that a facility, or a capital addition thereto, for the purpose of repowering to renewable energy is first placed in service for purposes of the implementing regulations of the Internal Revenue Code of 1986, as amended.

II. "Biomass fuels" means plant-derived fuel including clean and untreated wood such as brush, stumps, lumber ends and trimmings, wood pallets, bark, wood chips or pellets, shavings, sawdust and slash, agricultural crops, biogas, or liquid biofuels, but shall exclude any materials derived in whole or in part from construction and demolition debris.

III. "Certificate" means the record that identifies and represents each megawatt-hour generated by a renewable energy generating source under RSA 362-F:6.

IV. "Commission" means public utilities commission.

V. "Customer-sited source" means a source that is interconnected on the end-use customer's side of the retail electricity meter in such a manner that it displaces all or part of the metered consumption of the end-use customer.

VI. "Default service" means electricity supply that is available to retail customers who are otherwise without an electricity supplier as defined in RSA 374-F:2, I-a.

VII. "Department" means the department of environmental services.

VIII. "Eligible biomass technologies" means generating technologies that use biomass fuels as their primary fuel, provided that the generation unit:

(a) Has a quarterly average nitrogen oxide (NOx) emission rate of less than or equal to 0.075 pounds/million British thermal units (lbs/Mmbtu), and either has an average particulate emission rate of less than or equal to 0.02 lbs/Mmbtu as measured and verified under RSA 362-F:12 or is participating in a plan approved by the department under RSA 362-F:11, IV for reductions in particulate matter emissions from other emission sources comparable to the difference between the generation unit's particulate matter emissions rate and the 0.02 lbs/Mmbtu rate; and

(b) Uses any fuel other than the primary fuel only for start-up, maintenance, or other required internal needs.

IX. "End-use customer" means any person or entity that purchases electricity supply at retail in New

Hampshire from another person or entity but shall not include:

(a) A generating facility taking station service at wholesale from the regional market administered by the independent system operator (ISO-New England) or self-supplying from its other generating stations; and

(b) Prior to January 1, 2010, a customer who purchases retail electricity supply, other than default service under a supply contract executed prior to January 1, 2007.

X. "Historical generation baseline" means:

(a) The average annual electrical production from a facility other than hydroelectric, stated in megawatt-hours, for the 3 years 2004 through 2006, or for the first 36 months after the facility began operation if that date is after December 31, 2001; provided that the historical generation baseline shall be measured regardless of whether or not the emissions from the facility during the baseline period meets emissions requirements of the class.

(b) The average annual production of a hydroelectric facility from the later of January 1, 1986 or the date of first commercial operation through December 31, 2005. If the hydroelectric facility experienced an upgrade or expansion during the historical generation baseline period, actual generation for that entire period shall be adjusted to estimate the average annual production that would have occurred had the upgrade or expansion been in effect during the entire historical generation baseline period.

XI. "Methane gas" means biologically derived methane gas from anaerobic digestion of organic materials from such sources as yard waste, food waste, animal waste, sewage sludge, septage, and landfill waste.

XII. "New England control area" means the term as defined in ISO-New England's transmission, markets and services tariff, FERC electric tariff no. 3, section II.

XIII. "Primary fuel" means a fuel or fuels, either singly or in combination, that comprises at least 90 percent of the total energy input into a generating unit.

XIV. "Provider of electricity" means a distribution company providing default service or an electricity supplier as defined in RSA 374-F:2, II, but does not include municipal suppliers.

XV. "Renewable energy source," "renewable source," or "source" means a class I, II, III, or IV source of electricity or a class I source of useful thermal energy. An electrical generating facility, while selling its electrical output at long-term rates established before January 1, 2007 by orders of the commission under RSA 362-A:4, shall not be considered a renewable source.

XV-a. "Useful thermal energy" means renewable energy delivered from class I sources that can be metered and that is delivered in New Hampshire to an end user in the form of direct heat, steam, hot water, or other thermal form that is used for heating, cooling, humidity control, process use, or other valid thermal end use energy requirements and for which fuel or electricity would otherwise be consumed.

XVI. "Year" means a calendar year beginning January 1 and ending December 31.

Source. 2007, 26:2. 2008, 113:5, eff. Aug. 2, 2008; 368:3, eff. July 11, 2008. 2012, 272:1, 2, eff. June 19, 2012.

Section 362-F:3

362-F:3 Minimum Electric Renewable Portfolio Standards. – For each year specified in the table below, each provider of electricity shall obtain and retire certificates sufficient in number and class type to meet or exceed the following percentages of total megawatt-hours of electricity supplied by the provider to its end-use customers that year, except to the extent that the provider makes payments to the renewable energy fund under RSA 362-F:10, II:

	2008	2009	2010	2011	2012	2013	2014	2015	2025 and thereafter
Class I	0.0%	0.5%	1%	2%	3%	3.8%	5%	6%	15% (*)
Class II	0.0%	0.0%	0.04%	0.08%	0.15%	0.2%	0.3%	0.3%	0.3%
Class III	3.5%	4.5%	5.5%	6.5%	1.4%	1.5%	3.0%	8.0%	8.0%
Class IV	0.5%	1%	1%	1%	1%	1.3%	1.4%	1.5%	1.5%

*Class I increases an additional 0.9 percent per year from 2015 through 2025. A set percentage of the class I totals shall be satisfied annually by the acquisition of renewable energy certificates from qualifying renewable energy technologies producing useful thermal energy as defined in RSA 362-F:2, XV-a. The set percentage shall be 0.4 percent in 2014, 0.6 percent in 2015, 1.3 percent in 2016, and increased annually by 0.1 percent per year from 2017 through 2023, after which it shall remain unchanged. Classes II-IV remain at the same percentages from 2015 through 2025 except as provided in RSA 362-F:4, V-VI.

Source. 2007, 26:2, eff. July 10, 2007. 2012, 272:3, eff. June 19, 2012. 2013, 272:1, eff. July 24, 2013; 279:7, eff. July 27, 2013.

Section 362-F:4

362-F:4 Electric Renewable Energy Classes. –

I. Class I (New) shall include the production of electricity or useful thermal energy from any of the following, provided the source began operation after January 1, 2006, except as noted below:

(a) Wind energy.

(b) Geothermal energy, if the geothermal energy output is in the form of useful thermal energy only if the unit began operation after January 1, 2013.

(c) Hydrogen derived from biomass fuels or methane gas.

(d) Ocean thermal, wave, current, or tidal energy.

(e) Methane gas.

(f) Eligible biomass technologies.

(g) Solar thermal energy; if the solar thermal energy output is in the form of useful thermal energy only if the unit began operation after January 1, 2013.

(h) Class II sources to the extent that they are not otherwise used to satisfy the minimum portfolio standards of other classes.

(i) The incremental new production of electricity in any year from an eligible biomass or methane source or any hydroelectric generating facility licensed or exempted by Federal Energy Regulatory Commission (FERC), regardless of gross nameplate capacity, over its historical generation baseline, provided the commission certifies demonstrable completion of capital investments attributable to the efficiency improvements, additions of capacity, or increased renewable energy output that are sufficient to, were intended to, and can be demonstrated to increase annual renewable electricity output. The determination of incremental production shall not be based on any operational changes at such facility but rather on capital investments in efficiency improvements or additions of capacity.

(j) The production of electricity from a class III or IV source that has begun operation as a new facility by demonstrating that 80 percent of its resulting tax basis of the source's plant and equipment, but not its property and intangible assets, is derived from capital investment directly related to restoring generation or increasing capacity including department permitting requirements for new plants. Such production shall not qualify for class III or IV certificates. Commencing July 1, 2013, a class III source eligible as a class I source under this subparagraph or subparagraph (i) may submit a notice to the commission electing to be a class III source instead of a class I source. Once such notice is given, the production from such a source shall qualify for class III certificates, provided the source meets the other requirements of a class III eligible biomass technology.

(k) The production of electricity from any fossil-fueled generating facility that originally commenced operation prior to January 1, 2006, if after January 1, 2012 such facility co-fires with class I eligible biomass fuels to displace the combustion of an amount of fossil fuels. The portion of the total electrical energy output that qualifies as class I from a facility in a given time period shall be the fraction of electrical production derived from the combustion of biomass fuels based on the heat input at the facility in that time period as determined by the commission in consultation with the department. To qualify under this paragraph, the electricity generation facility that co-fires with biomass fuels shall:

(1) Either have a quarterly average nitrogen oxide (NOx) emission rate, as measured and verified under RSA 362-F:12, of less than or equal to 0.075 pounds/million British thermal units (lbs/Mmbtu) or be a participant in a plan approved by the department for reductions in NOx from other emission sources. The quantity of reductions required shall be the fraction of electrical production derived from the combustion of

biomass fuels, as determined under this paragraph, multiplied by the difference between the generation unit's NOx emissions rate and the 0.075 lbs/Mmbtu rate. The plan shall contain reductions, in the aggregate or individually, in NOx emissions from other emission sources under the jurisdiction of the department and demonstrate that the reductions will be quantifiable. The department shall expeditiously review the plan and, if approved, provide such information as it deems relevant to the commission. The application submitted to the commission under RSA 362-F:11 shall inform the commission of the plan and the commission shall certify the source in accordance with the plan approved by the department; and

(2) Either have an average particulate emission rate, as measured and verified under RSA 362-F:12, of less than or equal to 0.02 lbs/Mmbtu or be a participant in a plan approved by the department for reductions in particulate matter emissions from emission sources owned by or affiliated with the co-firing entity. The quantity of reductions required shall be the fraction of electrical production derived from the combustion of biomass fuels, as determined under this paragraph, multiplied by the difference between the generation unit's particulate matter emissions rate and the 0.02 lbs/Mmbtu rate. The plan shall contain reductions, in the aggregate or individually, in particulate matter emissions from other emission sources under the jurisdiction of the department and demonstrate that the reductions will be quantifiable. The department shall expeditiously review the plan and, if approved, provide such information as it deems relevant to the commission. The application submitted to the commission under RSA 362-F:11 shall inform the commission of the plan and the commission shall certify the source in accordance with the plan approved by the department.

(l) Biomass renewable energy technologies producing useful thermal energy that began operation after January 1, 2013 provided that:

(1) If the unit is a biomass unit rated between 3 and 30 Mmbtu/hr design gross heat input, it shall have an average particulate emission rate of less than or equal to 0.10 lbs/Mmbtu as measured and verified by conducting and reporting the results of a one-time initial stack test in accordance with methods approved by the department;

(2) If the unit is a biomass unit rated equal to or greater than 30 Mmbtu/hr design gross heat input, it shall have an average particulate emission rate of less than or equal to 0.02 lbs/Mmbtu as measured and verified under RSA 362-F:12;

(3) If the unit is a biomass unit rated less than 100 Mmbtu/hr design gross heat input, best management practices as determined by the department shall be implemented; and

(4) If the unit is a biomass unit rated equal to or greater than 100 Mmbtu/hr design gross heat input, it shall have a quarterly average NOx emission rate of less than or equal to 0.075 Mmbtu/hr as measured and verified under RSA 362-F:12; and

(5) If the unit is an upgrade or replacement to an existing source of thermal energy that used biomass as its primary fuel source in its normal operation prior to January 1, 2013, then the unit shall be a combined heat and power unit that provides district heating, and at least 80 percent of the resulting tax basis of the unit's plant and equipment, but not its property and intangible assets, shall be derived from capital investments directly related to the upgrade or replacement and made on or after January 1, 2013.

(m) The production of biodiesel, as defined in RSA 362-A:1-a, I-b, by any facility in New Hampshire, may be used to meet no more than 1/8 of a provider's nonthermal class I requirements in any given year under RSA 362-F:3, provided all applicable air emission and water discharge standards are met by the facility producing the biodiesel, the facility producing the biodiesel can document the sale of the biodiesel into the thermal energy market, and there is documentation of end-user efficiency rating, or where such documentation is not practicable, assuming the average end-user efficiency rating by customer class.

II. Class II (New Solar) shall include the production of electricity from solar technologies, provided the source began operation after January 1, 2006.

III. Class III (Existing Biomass/Methane) shall include the production of electricity from any of the following, provided the source began operation prior to January 1, 2006:

(a) Eligible biomass technologies having a gross nameplate capacity of 25 MWs or less.

(b) Methane gas.

IV. (a) Class IV (Existing Small Hydroelectric) shall include the production of electricity from hydroelectric energy, provided the facility:

(1) Began operation prior to January 1, 2006;

(2) When required, has documented applicable state water quality certification pursuant to section 401 of the Clean Water Act for hydroelectric projects; and

(3) Either:

(A) Has a total nameplate capacity of 5 MWs or less as measured by the sum of the nameplate capacities of all the generators at the facility and has actually installed both upstream and downstream diadromous fish passages and such installations have been approved by the Federal Energy Regulatory Commission, or;

(B) Has a total nameplate capacity of one MW or less as measured by the sum of the nameplate capacities of all generators at the facility, is in compliance with applicable Federal Energy Regulatory Commission fish passage restoration requirements, and is interconnected with an electric distribution system located in New Hampshire.

(b)(1) Notwithstanding subparagraph (a), the commission shall re-certify as class IV renewable energy sources the facilities named in commission order numbers 24,940 and 24,952. These facilities are:

(A) The Canaan, Gorham, Hooksett, and Jackman hydroelectric facilities owned by Public Service Company of New Hampshire, which had been previously certified by the commission on September 23, 2008; and

(B) The North Gorham and Bar Mills projects owned by FPL Energy Maine Hydro, LLC which had been previously certified by the commission on October 30, 2008.

(2) These facilities shall not qualify or be certified as class IV renewable energy sources after March 23, 2009, unless they meet the requirements of subparagraph (a). Such facilities shall be eligible for class IV renewable energy certificates for all electricity generated between the effective date of each facility's original certification by the commission through March 23, 2009. Such certificates shall have the same validity as any other class IV certificate issued under RSA 362-F, and may be sold, exchanged, banked, and utilized accordingly.

V. For good cause, and after notice and hearing, the commission may accelerate or delay by up to one year, any given year's incremental increase in class I or II renewable portfolio standards requirement under RSA 362-F:3.

VI. After notice and hearing, the commission may modify the class III and IV renewable portfolio standards requirements under RSA 362-F:3 for calendar years beginning January 1, 2012 such that the requirements are equal to an amount between 85 percent and 95 percent of the reasonably expected potential annual output of available eligible sources after taking into account demand from similar programs in other states.

Source. 2007, 26:2, eff. July 10, 2007. 2009, 86:1, eff. June 10, 2009. 2012, 272:4-7, 9, eff. June 19, 2012. 2013, 272:2, eff. July 24, 2013; 279:8, eff. July 27, 2013. 2016, 122:1, eff. July 19, 2016.

Section 362-F:5

362-F:5 Commission Review and Report. – Commencing in January 2011, 2018, and 2025 the commission shall conduct a review of the class requirements in RSA 362-F:3 and other aspects of the electric renewable portfolio standard program established by this chapter. Thereafter, the commission shall make a report of its findings to the general court by November 1, 2011, 2018, and 2025, respectively, including any recommendations for changes to the class requirements or other aspects of the electric renewable portfolio standard program. The commission shall review, in light of the purposes of this chapter and with due consideration of the importance of stable long-term policies:

I. The adequacy or potential adequacy of sources to meet the class requirements of RSA 362-F:3;

II. The class requirements of all sources in light of existing and expected market conditions;

III. The potential for addition of a thermal energy component to the electric renewable portfolio standard;

IV. Increasing the class requirements relative to classes I and II beyond 2025;

V. The possible introduction of any new classes such as an energy efficiency class or the consolidation of existing ones;

VI. The timeframe and manner in which new renewable class I and II sources might transition to and be treated as existing renewable sources and if appropriate, how corresponding portfolio standards of new and existing sources might be adjusted;

VII. The experience with and an evaluation of the benefits and risks of using multi-year purchase agreements for certificates, along with purchased power, relative to meeting the purposes and goals of this chapter at the least cost to consumers and in consideration of the restructuring policy principles of RSA 374-F:3; and

VIII. Alternative methods for renewable portfolio standard compliance, such as competitive procurement

through a centralized entity on behalf of all consumers in all areas of the state.
IX. The distribution of the renewable energy fund established in RSA 362-F:10.

Source. 2007, 26:2. 2008, 368:2, eff. July 11, 2008.

Section 362-F:6

362-F:6 Renewable Energy Certificates. –
I. The electric renewable portfolio standard program established in this chapter shall utilize the regional generation information system (GIS) of energy certificates administered by ISO-New England and the New England Power Pool (NEPOOL) or their successors. If the regional GIS certificate tracking program administered by the ISO-New England is no longer operational or accessible, the commission shall develop an alternative certificate program, after public notice and hearing, designed to provide at least the same information on the type and generation of renewable energy resources as the GIS certificate tracking program.
II. The commission shall establish procedures by which electricity and useful thermal energy production not tracked by ISO-New England from customer-sited sources, including behind the meter production, may be included within the certificate program, provided such sources are located in New Hampshire. The procedures may include the aggregation of sources and shall be compatible with procedures of the certificate program administrator, where possible. The production shall be monitored and verified by an independent entity designated by the commission, which may include electric distribution companies, or by such other means as the commission finds adequate in verifying that such production is occurring. For customer-sited sources under 15 kilowatts in capacity, the commission shall not require the independent monitors to perform an annual site visit, and shall allow the owner of the customer-sited source to electronically report production monthly to an independent monitor.
II-a. The commission shall establish a methodology to estimate the total yearly production for customer-sited sources that are net metered under RSA 362-A:9 and for which class I or II certificates are not issued. For purposes of estimation, the commission shall use a capacity factor rating of 20 percent for each installation and shall keep class II production separate from class I production. Providers of electricity required to obtain and retire certificates under RSA 362-F:3 shall receive an annual credit for such production. By February 28 of each year, the commission shall compute and make public credit percentages that are equal to the estimated production for the prior calendar year in each class divided by the total amount of electricity supplied by providers of electricity to end-use customers in the prior calendar year, with the result converted to a percentage. Each provider may then, at the time of its annual report filing under RSA 362-F:8, claim a class I and a class II certificate credit equal to the credit percentage times the total megawatt-hours of electricity supplied by the provider to its end-use customers the prior calendar year.
III. The commission shall designate in a timely manner New Hampshire eligible renewable sources together with any conditions pursuant to this chapter to the certificate program administrator under paragraph I, with such sources being the recipient of all certificates issued for purpose of this chapter.
IV. (a) Certificates issued for purposes of complying with this chapter shall come from sources within the New England control area unless the source is located in a synchronous control area adjacent to the New England control area and the energy produced by the source is actually delivered into the New England control area for consumption by New England customers. The delivery of such energy from the source into the New England control area shall be verified by:
(1) A unit-specific bilateral contract for sale and delivery of a source's electrical energy to the New England control area that is in place for the time period during which renewable certificates are generated;
(2) Confirmation from ISO-New England that the sale of the renewable energy was actually settled in the ISO market system; and
(3) Confirmation through the North American Electric Reliability Corporation tagging system that the import of energy into the New England control area actually occurred.
(b) The commission may impose such other requirements as it deems appropriate, including methods of confirming actual delivery of the electrical energy into the New England control area.
V. A qualified producer of useful thermal energy shall provide for the metering of useful thermal energy produced in order to calculate the quantity of megawatt-hours for which renewable energy certificates are qualified, and to report to the public utilities commission under rules adopted pursuant to RSA 362-F:13.

Monitoring, reporting, and calculating the useful thermal energy produced in each quarter shall be expressed in megawatt-hours, where each 3,412,000 BTUs of useful thermal energy is equivalent to one megawatt-hour.

Source. 2007, 26:2, eff. July 10, 2007. 2009, 86:2, eff. June 10, 2009. 2012, 272:10, 11, eff. June 19, 2012. 2014, 130:1, eff. Aug. 15, 2014.

Section 362-F:7

362-F:7 Sale, Exchange, and Use of Certificates. –
I. A certificate may be sold or otherwise exchanged by the source to which it was initially issued or by any other person or entity that acquires the certificate. A certificate may only be used once for compliance with the requirements of this chapter. It may not be used for compliance with this chapter if it has been or will be used for compliance with any similar requirements of another non-federal jurisdiction, or otherwise sold, retired, claimed, or represented as part of any other electrical energy output or sale. Certificates shall only be used by providers of electricity for compliance with the requirements of RSA 362-F:3 in the year in which the generation represented by the certificate was produced, except that unused certificates of the proper class issued for production during the prior 2 years may be used to meet up to 30 percent of a provider's requirements for a given class obligation in the current year of compliance.
II. Certificates from behind-the-meter distributed generation shall be initially issued to the owner of the customer-sited source or its designee, regardless of whether the source has received assistance from the renewable energy fund established in RSA 362-F:10.

Source. 2007, 26:2, eff. July 10, 2007. 2012, 272:12, eff. June 19, 2012.

Section 362-F:8

362-F:8 Information Collection. – By July 1 of each year, each provider of electricity shall submit a report to the commission, in a form approved by the commission, documenting its compliance with the requirements of this chapter for the prior year. The commission may investigate compliance and collect any information necessary to verify and audit the information provided to the commission by providers of electricity.

Source. 2007, 26:2, eff. July 10, 2007.

Section 362-F:9

362-F:9 Purchased Power Agreements. –
I. Upon the request of one or more electric distribution companies and after notice and hearing, the commission may authorize such company or companies to enter into multi-year purchase agreements with renewable energy sources for certificates, in conjunction with or independent of purchased power agreements from such sources, to meet reasonably projected renewable portfolio requirements and default service needs to the extent of such requirements, if it finds such agreements or such an approach, as may be conditioned by the commission, to be in the public interest.
II. In determining the public interest, the commission shall find that the proposal is, on balance, substantially consistent with the following factors:
(a) The efficient and cost-effective realization of the purposes and goals of this chapter;
(b) The restructuring policy principles of RSA 374-F:3;
(c) The extent to which such multi-year procurements are likely to create a reasonable mix of resources, in combination with the company's overall energy and capacity portfolio, in light of the energy policy set forth in RSA 378:37 and either the distribution company's integrated least cost resource plan pursuant to RSA 378:37-41, if applicable, or a portfolio management strategy for default service procurement that balances potential benefits and risks to default service customers;
(d) The extent to which such procurement is conducted in a manner that is administratively efficient and promotes market-driven competitive innovations and solutions; and

(e) Economic development and environmental benefits for New Hampshire.

III. The commission may authorize one or more distribution companies to coordinate or delegate procurement processes under this section.

IV. Rural electric cooperatives for which a certificate of deregulation is on file with the commission shall not be required to seek commission authorization for multi-year purchased power agreements or certificate purchase agreements under this section.

Source. 2007, 26:2, eff. July 10, 2007.

Section 362-F:10

362-F:10 Renewable Energy Fund. –

I. There is hereby established a renewable energy fund. This nonlapsing, special fund shall be continually appropriated to the commission to be expended in accordance with this section. The state treasurer shall invest the moneys deposited therein as provided by law. Income received on investments made by the state treasurer shall also be credited to the fund. All payments to be made under this section shall be deposited in the fund. Of the moneys paid into the fund, the amount of $520,000 for fiscal year 2016 shall be transferred to the division of homeland security and emergency management for the purpose of disaster and emergency response preparedness and coordination to help minimize utility and other disruptions resulting from natural or manmade disasters. Any remaining moneys paid into the fund under paragraph II of this section, excluding class II moneys, shall be used by the commission to support thermal and electrical renewable energy initiatives. Class II moneys shall primarily be used to support solar energy technologies in New Hampshire. All initiatives supported out of these funds shall be subject to audit by the commission as deemed necessary. All fund moneys including those from class II may be used to administer this chapter, but all new employee positions shall be approved by the fiscal committee of the general court. No new employees shall be hired by the commission due to the inclusion of useful thermal energy in class I production.

II. In lieu of meeting the portfolio requirements of RSA 362-F:3 for a given year if, and to the extent sufficient certificates are not otherwise available at a price below the amounts specified in this paragraph, an electricity provider may, at the time of report submission for that year under RSA 362-F:8, make payment to the commission at the following rates for each megawatt-hour not met for a given class obligation through the acquisition of certificates:

(a) Class I--$55, except for that portion of the class electric renewable portfolio standards to be met by qualifying renewable energy technologies producing useful thermal energy under RSA 362-F:3 which shall be $25 beginning January 1, 2013.

(b) Class II--$55.

(c) Class III--$31.50.

(d) Class IV--$26.50.

III. (a) Beginning in 2013, the commission shall adjust these rates by January 31 of each year using the Consumer Price Index as published by the Bureau of Labor Statistics of the United States Department of Labor for classes III and IV and 1/2 of such Index for classes I and II.

(b) In lieu of the adjustments under subparagraph (a) for class III in 2015, 2016 and 2017, the class rate in each of those years shall be $45.

(c) By January 31, 2018 the commission shall compute the 2018 class III rate to equal the rate that would have resulted in 2018 by the application of subparagraph (a) to the 2013 rate and each subsequent year's rate to 2018.

(d) In 2019 and thereafter, the class III rate shall be determined by application of subparagraph (a) to the prior year's rate.

IV. The commission shall make an annual report by October 1 of each year, beginning in 2009, to the legislative oversight committee on electric utility restructuring established under RSA 374-F:5, the house science, technology and energy committee, and the senate energy and natural resources committee detailing how the renewable energy fund is being used and any recommended changes to such use. The report shall also include information on the total peak generating capacity that is net energy metered under RSA 362-A:9 within the franchise area of each electric distribution utility, and the percentage this represents of the amount that is allowed to be net metered within each franchise area. Information shall be provided on net metered group host registrations and the associated customer groups, including number and location of group host facilities, generation by renewable source and size of facility, and group load served by such facilities.

V. The public utilities commission shall make and administer a one-time incentive payment of $3 per watt of nominal generation capacity up to a maximum payment of $6,000, or 50 percent of system costs, whichever is less, per facility to any residential owner of a small renewable generation facility, that would qualify as a Class I or Class II source of electricity, has a total peak generation capacity of 10 kilowatts or fewer, begins operation on or after July 1, 2008, and is located on or at the owner's residence.

VI. Such payments shall be allocated from the renewable energy fund established in paragraph I, as determined by the commission to the extent funding is available up to a maximum aggregate payment of 40 percent of the fund over each 2-year period commencing July 1, 2010.

VII. The commission shall, after notice and hearing, by order or rule establish an application process for the incentive payment program established under paragraph V. The application process shall include verification of costs for parts and labor, certification that the equipment used meets the applicable safety standards of the American National Standards Institute (ANSI) or Underwriters Laboratory (UL) or similar safety rating agency, and that the facility meets local zoning regulations, and receives any required inspections.

VIII. The commission may, after notice and hearing, by order or rule, establish additional incentive or rebate programs and competitive grant opportunities for renewable thermal and electric energy projects sited in New Hampshire.

IX. For good cause the commission may, after notice and hearing, by order or rule, modify the program, including reducing the incentive level, created under RSA 362-F:10, V.

X. Consistent with RSA 362-F:10, VI, the commission shall, over each 2-year period commencing July 1, 2010, reasonably balance overall amounts expended, allocated, or obligated from the fund, net of administrative expenditures, between residential and nonresidential sectors. Funds from the renewable energy fund awarded to renewable projects in the residential sector shall be in approximate proportion to the amount of electricity sold at retail to that sector in New Hampshire, and the remaining funds from the renewable energy fund shall be awarded to projects in the nonresidential sector which include commercial and industrial sited renewable energy projects, existing generators, and developers of new commercial-scale renewable generation in New Hampshire.

XI. The commission shall issue requests for proposals that provide renewable projects in the nonresidential sector, which include commercial and industrial sited renewable energy projects, existing generators, and developers of new commercial-scale renewable generation in New Hampshire, with opportunities to receive funds from the renewable energy fund established under RSA 362-F:10. The requests for proposals shall provide such opportunities to those renewable energy projects that are not eligible to participate in incentive and rebate programs developed by the commission under RSA 362-F:10, V and RSA 362-F:10, VIII. The commission shall issue a request for proposals no later than March 1, 2011 and annually thereafter, and select winning projects in a timely manner.

Source. 2007, 26:2. 2008, 368:1, eff. July 11, 2008. 2009, 86:3, eff. June 10, 2009. 2010, 143:4, eff. Aug. 13, 2010; 254:1-4, eff. July 6, 2010. 2012, 272:13, 14, eff. June 19, 2012. 2013, 266:3, eff. July 24, 2013; 272:3, eff. July 24, 2013; 279:1, 2, 9, eff. July 27, 2013. 2015, 276:224, eff. July 1, 2015. 2016, 319:16, eff. June 24, 2016.

Section 362-F:11

362-F:11 Application. –

I. The commission, in a non-adjudicative process, shall certify the classification of an existing or proposed generation facility by issuing a determination within 45 days of receiving from an applicant sufficient information to determine its classification. The application shall contain the following:

(a) Name and address of applicant.

(b) Facility location, ISO-New England asset identification number, and NEPOOL GIS facility code, if available.

(c) Description of the facility, including fuel type, gross generation capacity, initial commercial operation date, and, in the case of a biomass source, NOx and particulate matter emission rates and a description of pollution control equipment or practices proposed for compliance with applicable NOx and particulate matter emission rates.

(d) Such other information as the applicant may provide to assist in determining the classification of the generating facility.

II. The commission shall certify applications of customer-sited sources in a manner that is compatible with the procedures established for recognizing such production under RSA 362-F:6, II.

III. Biomass facilities otherwise meeting the requirements of a source shall be conditionally certified by the commission subject to compliance with the applicable NOx and particulate matter emission standards. Within 10 days of verification of compliance with emissions standards from the department, as provided in RSA 362-F:12, III, the commission, in a non-adjudicative process, shall designate the facility as eligible pursuant to RSA 362-F:6, III.

IV. A biomass facility otherwise meeting the eligibility requirements of class III, but which as of January 1, 2012 was not an eligible biomass technology due to the inability to achieve the particulate matter emissions rate specified in RSA 362-F:2, VIII(a), may consult with the department and submit a plan to meet the alternative requirement under that paragraph. The plan shall contain reductions, in the aggregate or individually, in emissions from other emission sources and demonstrate that the reductions will be quantifiable. The department shall expeditiously review the plan and, if approved, provide such information it deems relevant to the commission. The application submitted under this section shall inform the commission of the plan and the commission shall certify the source in accordance with the plan approved by the department.

Source. 2007, 26:2, eff. July 10, 2007. 2012, 272:15, eff. June 19, 2012.

Section 362-F:12

362-F:12 Verification of Emissions From Biomass Sources. – Any source seeking to qualify using an eligible biomass technology shall verify emissions in accordance with the following methods:

I. For nitrogen oxide emissions, the source shall install and operate a continuous emissions monitor that meets departmental standards as codified in rules.

II. For particulate matter emissions, the source shall conduct an annual stack test in accordance with methods approved by the department. Upon completion of 3 annual tests which demonstrate compliance, the source may request of the department for a decrease in the frequency of testing, but to not less than once every 3 years.

III. Each such source shall file with the department and the commission within 45 days of the end of each calendar quarter an affidavit and documentation attesting to the source's average NOx emission rate for such quarter and the most recent particulate matter stack test results. For purposes of initial certification under RSA 362-F:6, the results of a stack test may be filed with the department at any time to demonstrate compliance with both the particulate matter and nitrogen oxide emissions standards. Within 30 days of a filing, the department shall provide verification of the emissions reported in the filing to the commission.

Source. 2007, 26:2, eff. July 10, 2007.

Section 362-F:13

362-F:13 Rulemaking. – The commission shall adopt rules, under RSA 541-A, to:

I. Administer the electric renewable portfolio standard program including the development of an alternative to the regional generation information system to the extent necessary.

II. Ascertain, monitor, and enforce compliance with the program to the extent not addressed in the department's rules.

III. Include within the program electric production not tracked by ISO-New England from eligible customer-sited sources.

IV. Administer the renewable energy fund and make expenditures from the fund.

V. Establish procedures for the classification of existing or proposed generation facilities, including a provision for a preliminary designation option, and to verify the completion of capital investments required of certain class I resources.

VI. Define when a repowered generation unit qualifies as a new class I source under RSA 362-F:4.

VI-a. Adopt procedures for the metering, verification, and reporting of useful thermal energy output.

VI-b. Establish procedures for the metering, verification, and reporting of useful thermal energy output for producers of biodiesel no later than December 31, 2017.

VII. Otherwise discharge the responsibilities delegated to the commission under this chapter.

VIII. The department may adopt rules, under RSA 541-A, to determine best management practices for qualifying renewable energy technologies producing useful thermal energy.

Source. 2007, 26:2, eff. July 10, 2007. 2012, 272:16, 17, eff. June 19, 2012. 2016, 122:2, eff. July 19, 2016.

Section 362-F:14

362-F:14 Phase-In for Existing Supply Contract Load. – The increases in the annual purchase percentages in RSA 362-F:3 as compared to those in effect as of January 1, 2012 shall apply to the electrical load under any electrical power supply contracts for a term of years entered into by providers of electricity prior to or on July 1, 2012, upon the expiration of the term of any such contract. Providers of electricity shall inform the commission by July 1 of each year of all such contracts and their terms, including but not limited to the execution date and expiration date of the contract and the annual volume of electrical energy supplied.

Source. 2012, 272:18, eff. June 19, 2012.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 365
COMPLAINTS TO, AND PROCEEDINGS BEFORE, THE COMMISSION

Proceedings Before the Commission

Section 365:21

365:21 Rehearings and Appeals. – The procedure for rehearings and appeals shall be that prescribed by RSA 541, except as herein otherwise provided. Notwithstanding RSA 541:5, upon the filing of a motion for rehearing, the commission shall within 30 days either grant or deny the motion, or suspend the order or decision complained of pending further consideration, and any order of suspension may be upon such terms and conditions as the commission may prescribe.

Source. 1951, 203:11 par. 21, eff. Sept. 1, 1951. 2014, 24:1, eff. July 22, 2014.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 374
GENERAL REGULATIONS

General Public Utility Duty

Section 374:1

374:1 Service. – Every public utility shall furnish such service and facilities as shall be reasonably safe and adequate and in all other respects just and reasonable.

Source. 1911, 164:4. PL 240:1. RL 289:1. 1951, 203:21, eff. Sept. 1, 1951.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 374
GENERAL REGULATIONS

General Public Utility Duty

Section 374:2

374:2 Charges. – All charges made or demanded by any public utility for any service rendered by it or to be rendered in connection therewith, shall be just and reasonable and not more than is allowed by law or by order of the public utilities commission. Every charge that is unjust or unreasonable, or in excess of that allowed by law or by order of the commission, is prohibited.

Source. 1911, 164:4. PL 240:2. RL 289:2. 1951, 203:22, eff. Sept. 1, 1951.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 374
GENERAL REGULATIONS

Purchase of Capacity

Section 374:57

374:57 Purchase of Capacity. – Each electric utility which enters into an agreement with a term of more than one year for the purchase of generating capacity, transmission capacity or energy shall furnish a copy of the agreement to the commission no later than the time at which the agreement is filed with the Federal Energy Regulatory Commission pursuant to the Federal Power Act or, if no such filing is required, at the time such agreement is executed. The commission may disallow, in whole or part, any amounts paid by such utility under any such agreement if it finds that the utility's decision to enter into the transaction was unreasonable and not in the public interest.

Source. 1989S, 1:2, eff. Dec. 18, 1989.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 374-A
AUTHORIZING ELECTRIC UTILITIES TO PARTICIPATE IN ELECTRIC POWER FACILITIES

Section 374-A:1

374-A:1 Definitions. – In this chapter:

I. "Commission" means the public utilities commission.

II. "Domestic electric utility" means an electric utility resident in, or organized under the laws of this state.

III. "Electric power facilities" means generating units rated 25 megawatts or above and transmission facilities rated 69 kilovolts or above planned to be placed in service in New England after June 24, 1975.

IV. "Electric utility" means any individual or entity or subdivision thereof, private, governmental or other, including a municipal utility, wherever resident or organized, primarily engaged in the generation and sale or the purchase and sale of electricity or the transmission thereof, for ultimate consumption by the public.

V. "Foreign electric utility" means any electric utility other than a domestic electric utility.

VI. "Municipal utility" means a city, county, town or village district within the state, engaged in the generation and sale or the purchase and sale of electricity or the transmission thereof, for ultimate consumption by the public under RSA 38, RSA 52 or any special laws. Except where otherwise specifically provided, a municipal utility may exercise any of its powers or authority contained in this chapter through its municipal officers or members of the board of commissioners in whom the management of such municipal utility is vested.

Source. 1975, 501:1. 1986, 70:1, eff. July 11, 1986.

Authority, Taxation, Regulation

Section 374-A:2

374-A:2 Powers of Domestic Electric Utilities. – Notwithstanding any contrary provision of any general or special law relating to the powers and authorities of domestic electric utilities or any limitation imposed by a corporate or municipal charter, but subject to the conditions set forth in this chapter, a domestic electric utility shall have the following additional powers:

I. To jointly or separately plan, finance, construct, purchase, operate, maintain, use, share costs of, own, mortgage, lease, sell, dispose of or otherwise participate in electric power facilities or portions thereof within or without the state or the product or service therefrom or securities issued in connection with the financing of electric power facilities or portions thereof; and

II. To enter into and perform contracts and agreements for such joint or separate planning, financing, construction, purchase, operation, maintenance, use, sharing costs of, ownership, mortgaging, leasing, sale, disposal of or other participation in electric power facilities, or portions thereof, or the product or service therefrom, or securities issued in connection with the financing of electric power facilities or portions thereof, including, without limitation, contracts and agreements for the payment of obligations imposed without regard to the operational status of a facility or facilities and contracts and agreements with domestic or foreign electric utilities for the sale or purchase of electricity from an electric power facility or facilities for long or short periods of time or for the life of a specific electric generating unit or units. Such contracts and agreements may contain provisions for arbitration, delegation, non-unanimous amendment and any other matters deemed necessary or desirable to carry out their purposes.

Nothing in this section shall be construed to authorize a domestic electric utility to sell electricity at wholesale or retail within or without this state except:

(a) As otherwise authorized by or under its charter or the general or special laws of this state other than by this chapter;

(b) In connection with sales of economy, backup and other energy; and

(c) For any sale or sales of capacity and related energy from a specifically identified generating unit which is an electric power facility.

Source. 1975, 501:1, eff. June 24, 1975.

Section 374-A:2-a

374-A:2-a Municipal Purchase and Distribution of Electricity. – Notwithstanding any provision of law to the contrary, a municipality may enter into an agreement with another municipality in order to jointly purchase electrical service from a facility or provider. Any municipality which enters into such an agreement may distribute electricity to any municipality which is a party to the agreement.

Source. 1996, 192:1, eff. Aug. 2, 1996.

Section 374-A:3

374-A:3 Powers of Foreign Electric Utilities. – Notwithstanding any contrary provision of any general or special law relating to the powers and authorities of foreign electric utilities, but subject to the conditions set forth in this chapter, a foreign electric utility shall have the following additional powers: Jointly, with one or more other electric utilities, including at least one domestic electric utility, to construct, purchase, operate, maintain, use, own, mortgage, lease, sell, dispose of or otherwise participate in electric power facilities or portions thereof within this state or the product or service therefrom and in connection therewith to enter into and perform within the state contracts and agreements as provided in RSA 374-A:2, II; provided, however, that nothing in this section shall be construed to exempt from state regulation any facility, product or service to which this section applies or to authorize a foreign electric utility to sell electricity at wholesale or retail within this state except:

I. As otherwise authorized by or under the laws of this state other than this chapter;

II. In connection with sales of economy, backup and other energy; and

III. For any sale or sales of capacity and related energy from a specifically identified generating unit which is an electric power facility.

Source. 1975, 501:1, eff. June 24, 1975.

Section 374-A:4

374-A:4 Joint Ownership and Waiver of the Right of Partition. – If any domestic or foreign electric utility acquires or owns an interest as a tenant in common with one or more other domestic or foreign electric utilities in any electric power facilities in this state, the surrender or waiver by any such owner of such property of its right to partition such property shall not be invalid or unenforceable as unduely restricting the alienation of such property.

Source. 1975, 501:1, eff. June 24, 1975.

Section 374-A:5

374-A:5 Taxation. –

I. All electric power facilities, real and personal, situated within the state of any domestic electric utility other than a municipal utility, all such facilities of a municipal utility situated within the state but without its corporate limits, and all such facilities situated within the state of any foreign electric utility shall be subject to assessment and taxation as tangible property in the same manner and to the same extent as is provided by law with respect to such property of a corporation defined as a "public utility" in RSA 362:2.

II. Legislative consent is hereby given to the application to any domestic electric utility which has acquired or has an interest in an electric power facility, real or personal, situated without the state, or which is acting without the state pursuant to authority granted in this chapter, of the laws of other states with respect to taxation, payments in lieu of taxes, and the assessment thereof.

Source. 1975, 501:1, eff. June 24, 1975.

Section 374-A:6

374-A:6 Regulation of Domestic Electric Utilities. –

I. (a) Notwithstanding the exception for municipal corporations operating within their corporate limits provided in RSA 362:2, any municipal utility which acquires or is acquiring or has any interest in an electric power facility located within its corporate limits or elsewhere shall, with respect to such facility so long as it retains such interest therein, be considered a "public utility" for all purposes of RSA Title XXXIV and a corporation to which the provisions of RSA 231:159-182 shall be applicable, provided that RSA 231:159-182 to the extent not now applicable to a municipal utility shall be applicable to such a utility only with respect to those facilities constituting electric power facilities; provided, however, that nothing in this section shall be deemed to affect either such municipal utility's exemption from public utility status while operating within its corporate limits or such municipal utility's status as a public utility while operating outside its corporate limits, except in either case with respect to its interest in such facility; and provided, further, that the following requirements of RSA Title XXXIV shall be applicable only to the extent, if any, hereinafter specified:

(1) The provisions of RSA 367, 368, 372, 373, 375-A, 376, 377, 379, 380, 381, and 382 and all sections in RSA Title XXXIV relating solely to public utilities other than electric utilities shall not apply to any such municipal utility;

(2) The provisions of RSA 363-A and 364 and the provisions of RSA 366:8, 369:8, 369:14-16, 374:12, and 374:32 shall not apply to any such municipal utility;

(3) The provisions of RSA 371 shall be applicable to a municipal utility only with respect to those facilities constituting electric power facilities; and

(4) The provisions of RSA 378 shall apply only to rates, prices and charges made by any such municipal utility for sales of electricity other than to the ultimate consumer thereof.

(b) In construing all sections of RSA Title XXXIV where reference is made to officers or directors of a public utility, such provisions shall, where applicable to any municipal utility by virtue of the provisions of subparagraph (a), be deemed to include the municipal officers or members of the board of commissioners in whom the management of such municipal utility is vested.

(c) Notwithstanding any other provision of law, any municipal charter, or any ordinance or bylaw adopted thereunder, competitive bidding shall not be required in connection with the purchase of equipment, supplies or materials required for the construction or operation of electric power facilities. Any provision of any law, municipal charter, ordinance or bylaw relating to contracts awarded by municipalities or municipal utilities for construction, reconstruction, alteration, remodeling, repair, demolition, equipment, supplies or materials shall not be applicable to contracts related to electric power facilities wherever the utility or utilities having primary responsibility for the construction or operation of the facility are not municipal utilities.

II. Legislative consent is hereby given to the application to any domestic electric utility which is acting without the state, pursuant to authority granted in this chapter, of regulatory and other laws of other states and of the United States.

III. In addition to ownership, sole or joint in electric power facilities, the commission shall include in the rate base of a domestic electric utility any investments, including securities, prepayments or other investments, acquired by it in connection with its participation in an electric power facility within or without the state.

Source. 1975, 501:1, eff. June 24, 1975. 2013, 100:9, eff. Aug. 23, 2013.

Section 374-A:7

374-A:7 Regulation of Foreign Electric Utilities. –

I. Each foreign electric utility which is acting pursuant to authority granted in this chapter shall, before owning or operating any electric power facilities in this state, notify the commission of the action to be taken by it and obtain the commission's permission under RSA 374:22 and 26 to the extent such permission is required by RSA 374:22; shall thereafter furnish to the commission annually a copy of the annual report filed by it with the utility regulatory agency of the state of its domicile or principal locus; and shall furnish to the commission from time to time such other information with respect to its activities in the state as the commission may reasonably request;

II. Any foreign electric utility which owns or operates any electric power facilities in this state shall:

(a) File with the secretary of state as a foreign corporation doing business in New Hampshire and consent to service of process pursuant to the provisions of RSA 293-A;

(b) Be subject to and comply with all laws and regulations applicable to the construction, operation and use of such electric power facilities; provided, however, that such foreign electric utility shall not be deemed to be a public utility for the purposes of RSA Title XXXIV except in relation to its activities as a participant in electric power facilities within the state and except to the extent that the activities in this state of such foreign electric utility exclusive of such participation in electric power facilities shall cause it to be deemed a public utility; and

(c) Be subject to the requirements of RSA 369 and other regulatory laws within the state with respect to any financing of its interest in such electric power facilities, including any borrowing or the issuance of any notes, bonds or other evidence of indebtedness or securities of any nature; provided, however, that it shall be exempt from the requirements of this subparagraph upon certification filed with the commission by a regulatory agency of the state of domicile or principal locus of such foreign electric utility, or of the United States, either that said regulatory agency has general regulatory jurisdiction over the financing of such foreign electric utility or that said regulatory agency has exercised jurisdiction over, or has reviewed and not objected to, a particular proposed financing or that said regulatory agency has general supervision of such foreign electric utility in the conduct of its electric business.

Source. 1975, 501:1, eff. June 24, 1975.

Application of Related Laws

Section 374-A:8

374-A:8 Proceedings to Acquire Property or to Obtain Rights in Public Waters and Lands. – Electric generating stations, electric substations, and lines for transmission of electricity which are electric power facilities, irrespective of the destination and ultimate use of the electricity to be so generated and transmitted, shall be electric generating stations, electric substations, and lines for transmission of electricity for which an electric utility, domestic or foreign, may petition under RSA 371 for permission to take lands, rights or easements by eminent domain or for a license to construct and maintain facilities over, under or across public waters or state lands, provided that the commission shall find that such facilities will provide a substantial benefit to the public in this state.

Source. 1975, 501:1, eff. June 24, 1975.

Section 374-A:9

374-A:9 Provision for Exemption From Zoning Regulations. – For purposes of RSA 674:30, an electric power facility located within the state and used or to be used by one or more domestic or foreign electric utilities pursuant to authority set forth in this chapter shall be considered a structure used or to be used by a public utility, and each such utility, shall be considered a public utility.

Source. 1975, 501:1, eff. June 24, 1975.

Section 374-A:10

374-A:10 Severability. – This chapter shall be construed in all respects so as to meet all constitutional requirements. Except as expressly provided, this chapter shall not affect the interpretation of other laws. If any provision or clause of this chapter, or the application thereof to any person or circumstance, is held invalid, such invalidity shall not affect other provisions or applications of this chapter, and to that end, the provisions of this chapter are declared to be severable. Each section of this chapter shall be separable from all other sections hereof and the nullification of any section from this chapter shall have no effect on the remaining sections of this chapter.

Source. 1975, 501:1, eff. June 24, 1975.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 374-F
ELECTRIC UTILITY RESTRUCTURING

Section 374-F:1

374-F:1 Purpose. –
I. The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. Increased customer choice and the development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry that will require unbundling of prices and services and at least functional separation of centralized generation services from transmission and distribution services.
II. A transition to competitive markets for electricity is consistent with the directives of part II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it." Competitive markets should provide electricity suppliers with incentives to operate efficiently and cleanly, open markets for new and improved technologies, provide electricity buyers and sellers with appropriate price signals, and improve public confidence in the electric utility industry.
III. The following interdependent policy principles are intended to guide the New Hampshire public utilities commission in implementing a statewide electric utility industry restructuring plan, in establishing interim stranded cost recovery charges, in approving each utility's compliance filing, in streamlining administrative processes to make regulation more efficient, and in regulating a restructured electric utility industry. In addition, these interdependent principles are intended to guide the New Hampshire general court and the department of environmental services and other state agencies in promoting and regulating a restructured electric utility industry.

Source. 1996, 129:2, eff. May 21, 1996.

Section 374-F:2

374-F:2 Definitions. – In this chapter:
I. "Commission" means the public utilities commission.
I-a. "Default service" means electricity supply that is available to retail customers who are otherwise without an electricity supplier and are ineligible for transition service.
II. "Electricity suppliers" means suppliers of electricity generation services and includes actual electricity generators and brokers, aggregators, and pools that arrange for the supply of electricity generation to meet retail customer demand, which may be municipal or county entities.
III. "FERC" means the Federal Energy Regulatory Commission.
IV. "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;

(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.;

(d) Costs approved for recovery by the commission in connection with the divestiture or retirement of Public Service Company of New Hampshire generation assets pursuant to RSA 369-B:3-a; and

(e) All costs incurred as a result of fulfilling employee protection obligations pursuant to RSA 369-B:3-b.

V. "Transition service" means electricity supply that is available to existing retail customers prior to each customer's first choice of a competitive electricity supplier and to others, as deemed appropriate by the commission.

Source. 1996, 129:2. 1998, 191:3, 4. 2003, 56:2, eff. July 20, 2003. 2014, 310:4, eff. Sept. 30, 2014.

Section 374-F:3

374-F:3 Restructuring Policy Principles. –

I. System Reliability. Reliable electricity service must be maintained while ensuring public health, safety, and quality of life.

II. Customer Choice. Allowing customers to choose among electricity suppliers will help ensure fully competitive and innovative markets. Customers should be able to choose among options such as levels of service reliability, real time pricing, and generation sources, including interconnected self generation. Customers should expect to be responsible for the consequences of their choices. The commission should ensure that customer confusion will be minimized and customers will be well informed about changes resulting from restructuring and increased customer choice.

III. Regulation and Unbundling of Services and Rates. When customer choice is introduced, services and rates should be unbundled to provide customers clear price information on the cost components of generation, transmission, distribution, and any other ancillary charges. Generation services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services which should remain regulated for the foreseeable future. However, distribution service companies should not be absolutely precluded from owning small scale distributed generation resources as part of a strategy for minimizing transmission and distribution costs. Performance based or incentive regulation should be considered for transmission and distribution services. Upward revaluation of transmission and distribution assets is not a preferred mechanism as part of restructuring. Retail electricity suppliers who do not own transmission and distribution facilities, should, at a minimum, be registered with the commission.

IV. Open Access to Transmission and Distribution Facilities. Non-discriminatory open access to the electric system for wholesale and retail transactions should be promoted. Comparability should be assured for generators competing with affiliates of groups supplying transmission and distribution services. Companies providing transmission services should file at the FERC or with the commission, as appropriate, comparable service tariffs that provide open access for all competitors. The commission should monitor companies providing transmission or distribution services and take necessary measures to ensure that no supplier has an unfair advantage in offering and pricing such services.

V. Universal Service. (a) Electric service is essential and should be available to all customers. A utility providing distribution services must have an obligation to connect all customers in its service territory to the distribution system. A restructured electric utility industry should provide adequate safeguards to assure universal service. Minimum residential customer service safeguards and protections should be maintained. Programs and mechanisms that enable residential customers with low incomes to manage and afford essential electricity requirements should be included as a part of industry restructuring.

(b) As competitive markets emerge, customers should have the option of stable and predictable ceiling electricity prices through a reasonable transition period, consistent with the near term rate relief principle of RSA 374-F:3, XI. Upon the implementation of retail choice, transition service should be available for at least one but not more than 5 years after competition has been certified to exist in at least 70 percent of the state pursuant to RSA 38:36, for customers who have not yet chosen a competitive electricity supplier. Transition service should be procured through competitive means and may be administered by independent third parties. The price of transition service should increase over time to encourage customers to choose a competitive electricity supplier during the transition period. Such transition service should be separate and distinct from default service.

(c) Default service should be designed to provide a safety net and to assure universal access and system integrity. Default service should be procured through the competitive market and may be administered by independent third parties. Any prudently incurred costs arising from compliance with the renewable portfolio standards of RSA 362-F for default service or purchased power agreements shall be recovered through the default service charge. The allocation of the costs of administering default service should be borne by the customers of default service in a manner approved by the commission. If the commission determines it to be in the public interest, the commission may implement measures to discourage misuse, or long-term use, of default service. Revenues, if any, generated from such measures should be used to defray stranded costs.

(d) The commission should establish transition and default service appropriate to the particular circumstances of each jurisdictional utility.

(e) Notwithstanding any provision of subparagraphs (b) and (c), as competitive markets develop, the commission may approve alternative means of providing transition or default services which are designed to minimize customer risk, not unduly harm the development of competitive markets, and mitigate against price volatility without creating new deferred costs, if the commission determines such means to be in the public interest.

(f)(1) For purposes of subparagraph (f), "renewable energy source" (RES) means a source of electricity, as defined in RSA 362-F:2, XV, that would qualify to receive renewable energy certificates under RSA 362-F, whether or not it has been designated as eligible under RSA 362-F:6, III.

(2) A utility shall provide to its customers one or more RES options, as approved by the commission, which may include RES default service provided by the utility or the provision of retail access to competitive sellers of RES attributes. Costs associated with selecting an RES option should be paid for by those customers choosing to take such option. A utility may recover all prudently incurred administrative costs of RES options from all customers, as approved by the commission.

(3) RES default service should have either all or a portion of its service attributable to a renewable energy source component procured by the utility, with any remainder filled by standard default service. The price of any RES default service shall be approved by the commission.

(4) Under any option offered, the customer shall be purchasing electricity generated by renewable energy sources or the attributes of such generation, either in connection with or separately from the electricity produced. The regional generation information system of energy certificates administered by the ISO-New England and the New England Power Pool (NEPOOL) should be considered at least one form of certification that is acceptable under this program.

(5) A utility that is required by statute to provide default service from its generation assets should use any of its owned generation assets that are powered by renewable energy for the provision of standard default service, rather than for the provision of a renewable energy source component.

(6) Utilities should include educational materials in their normal communications to their customers that explain the RES options being offered and the health and environmental benefits associated with them. Such educational materials should be compatible with any environmental disclosure requirements established by the commission.

(7) For purposes of consumer protection and the maintenance of program integrity, reasonable efforts should be made to assure that the renewable energy source component of an RES option is not separately advertised, claimed, or sold as part of any other electricity service or transaction, including compliance with the renewable portfolio standards under RSA 362-F.

(8) If RES default service is not available for purchase at a reasonable cost on behalf of consumers choosing an RES default service option, a utility may, as approved by the commission, make payments to the renewable energy fund created pursuant to RSA 362-F:10 on behalf of customers to comply with subparagraph (f).

(9) The commission shall implement subparagraph (f) through utility-specific filings. Approved RES options shall be included in individual tariff filings by utilities.

(10) A utility, with commission approval, may require that a minimum number of customers, or a minimum amount of load, choose to participate in the program in order to offer an RES option.

VI. Benefits for All Consumers. Restructuring of the electric utility industry should be implemented in a manner that benefits all consumers equitably and does not benefit one customer class to the detriment of another. Costs should not be shifted unfairly among customers. A nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system may be used to fund public benefits related to the provision of electricity. Such benefits, as approved by regulators, may include, but not necessarily be limited to, programs for low-income customers, energy efficiency programs, funding for the electric utility industry's share of commission expenses pursuant to RSA 363-A, support for research and development, and investments in commercialization strategies for new and beneficial technologies.

VII. Full and Fair Competition. Choice for retail customers cannot exist without a range of viable suppliers. The rules that govern market activity should apply to all buyers and sellers in a fair and consistent manner in order to ensure a fully competitive market.

VIII. Environmental Improvement. Continued environmental protection and long term environmental sustainability should be encouraged. Increased competition in the electric industry should be implemented in a manner that supports and furthers the goals of environmental improvement. Over time, there should be more equitable treatment of old and new generation sources with regard to air pollution controls and costs. New Hampshire should encourage equitable and appropriate environmental regulation, based on comparable criteria, for all electricity generators, in and out of state, to reduce air pollution transported across state lines and to promote full, free, and fair competition. As generation becomes deregulated, innovative market-driven approaches are preferred to regulatory controls to reduce adverse environmental impacts. Such market approaches may include valuing the costs of pollution and using pollution offset credits.

IX. Renewable Energy Resources. Increased future commitments to renewable energy resources should be consistent with the New Hampshire energy policy as set forth in RSA 378:37 and should be balanced against the impact on generation prices. Over the long term, increased use of cost-effective renewable energy technologies can have significant environmental, economic, and security benefits. To encourage emerging technologies, restructuring should allow customers the possibility of choosing to pay a premium for electricity from renewable resources and reasonable opportunities to directly invest in and interconnect decentralized renewable electricity generating resources.

X. Energy Efficiency. Restructuring should be designed to reduce market barriers to investments in energy efficiency and provide incentives for appropriate demand-side management and not reduce cost-effective customer conservation. Utility sponsored energy efficiency programs should target cost-effective opportunities that may otherwise be lost due to market barriers.

XI. Near Term Rate Relief. The goal of restructuring is to create competitive markets that are expected to produce lower prices for all customers than would have been paid under the current regulatory system. Given New Hampshire's higher than average regional prices for electricity, utilities, in the near term, should work to reduce rates for all customers. To the greatest extent practicable, rates should approach competitive regional electric rates. The state should recognize when state policies impose costs that conflict with this principle and should take efforts to mitigate those costs. The unique New Hampshire issues contributing to the highest prices in New England should be addressed during the transition, wherever possible.

XII. Recovery of Stranded Costs.

(a) It is the intent of the legislature to provide appropriate tools and reasonable guidance to the commission in order to assist it in addressing claims for stranded cost recovery and fulfilling its responsibility to determine rates which are equitable, appropriate, and balanced and in the public interest. In making its determinations, the commission shall balance the interests of ratepayers and utilities during and after the restructuring process. Nothing in this section is intended to provide any greater opportunity for stranded cost recovery than is available under applicable regulation or law on the effective date of this chapter.

(b) Utilities should be allowed to recover the net nonmitigatable stranded costs associated with required environmental mandates currently approved for cost recovery, and power acquisitions mandated by federal statutes or RSA 362-A.

(c) Utilities have had and continue to have an obligation to take all reasonable measures to mitigate stranded costs. Mitigation measures may include, but shall not be limited to:

(1) Reduction of expenses.

(2) Renegotiation of existing contracts.

(3) Refinancing of existing debt.

(4) A reasonable amount of retirement, sale, or write-off of uneconomic or surplus assets, including regulatory assets not directly related to the provision of electricity service.

(d) Stranded costs should be determined on a net basis, should be verifiable, should not include transmission and distribution assets, and should be reconciled to actual electricity market conditions from time to time. Any recovery of stranded costs should be through a nonbypassable, nondiscriminatory, appropriately structured charge that is fair to all customer classes, lawful, constitutional, limited in duration, consistent with the promotion of fully competitive markets and consistent with these principles. Entry and exit fees are not preferred recovery mechanisms. Charges to recover stranded costs should only apply to customers within a utility's retail service territory, except for such costs that have resulted from the provision of wholesale power to another utility. The charges should not apply to wheeling-through transactions.

XIII. Regionalism. New England Power Pool (NEPOOL) should be reformed and efforts to enhance competition and to complement industry restructuring on a regional basis should be encouraged. New Hampshire should work with other New England and northeastern states to accomplish the goals of restructuring. Working with other regional states, New Hampshire should assert maximum state authority over the entire electric industry restructuring process. While it is desirable to design and implement a restructured industry in concert with the other New England and northeastern states, New Hampshire should not unnecessarily delay its timetable. Any pool structure adopted for the restructured industry should not preclude bilateral contracts with pool and non-pool services and should not preclude ancillary pool services from being obtained from non-pool sources.

XIV. Administrative Processes. The commission should adapt its administrative processes to make regulation more efficient and to enable competitors to adapt to changes in the market in a timely manner. The market framework for competitive electric service should, to the extent possible, reduce reliance on administrative process. New Hampshire should move deliberately to replace traditional planning mechanisms with market driven choice as the means of supplying resource needs.

XV. Timetable. The commission should seek to implement full customer choice among electricity suppliers in the most expeditious manner possible, but may delay such implementation in the service territory of any electric utility when implementation would be inconsistent with the goal of near-term rate relief, or would otherwise not be in the public interest.

Source. 1996, 129:2. 1998, 191:5. 2000, 249:3. 2001, 29:5, 6. 2002, 212:6; 268:4. 2006, 294:3. 2007, 26:4, eff. July 10, 2007. 2009, 236:1, eff. Nov. 13, 2009.

Section 374-F:4

374-F:4 Implementation. –

I. The commission is authorized to require the implementation of retail choice of electric suppliers for all customer classes of utilities providing retail electric service under its jurisdiction. The commission shall require such implementation at the earliest date determined to be in the public interest by the commission. However, in no event may the implementation be delayed beyond July 1, 1998 without legislative approval or a finding of public interest by the commission that delay is required due to events beyond the control of the commission or that implementation of retail choice within the service territory of any electric utility would be inconsistent with the goal of near-term rate relief or would otherwise not be in the public interest. In the event that implementation of retail choice is delayed in the service territory of an electric utility, the electric utility shall continue to provide reliable retail service at the lowest reasonable cost in accordance with state law. In addition, at the earliest practical date, the commission should make effective the unbundling of components of rates into at least distribution, transmission, and generation for each jurisdictional utility.

II. Upon the effective date of this chapter, the commission shall undertake a generic proceeding to develop a statewide industry restructuring plan in accordance with the above principles, and shall, after public hearings, issue a final order no later than February 28, 1997. In its order, the commission shall establish the interim stranded cost recovery charge for each electric utility as provided in paragraph VI.

III. The commission shall require all electric utilities subject to its jurisdiction to submit compliance filings, which shall include open access tariffs and such other information as the commission may require, no later than June 30, 1997. The commission shall investigate and shall approve utility compliance filings, subject to modification by the commission if necessary, after public hearing and subject to a finding that the filings are in the public interest and substantially consistent with the principles established in this chapter.

IV. A utility having less than a 50 percent share of statewide retail electric distribution sales (measured in kilowatt hours per year) may seek a ruling by the commission that it is in the public interest that implementation of such utility's compliance filing be deferred until compliance filings representing 70 percent of retail electric sales have been or are being implemented.

V. The commission is authorized to allow utilities to collect a stranded cost recovery charge, subject to its determination in the context of a rate case or adjudicated settlement proceeding that such charge is equitable, appropriate, and balanced, is in the public interest, and is substantially consistent with these interdependent principles. The burden of proof for any stranded cost recovery claim shall be borne by the utility making such claim.

VI. (a) In order to facilitate the rapid transition to full competition, the commission is authorized, in its generic restructuring order as provided in paragraph II, to set, without a formal rate case proceeding, an interim stranded cost recovery charge for each electric utility. Such interim stranded cost recovery charges shall be effective for not more than 2 years from the implementation of utility compliance filings and shall be based on the commission's preliminary determination of an equitable, appropriate, and balanced measure of stranded cost recovery that takes into account the near term rate relief principle, is in the public interest, and is substantially consistent with these interdependent principles. The commission shall also consider the potential for future rate impacts due to possible differences between interim stranded cost recovery charges and charges that may finally be approved for stranded cost recovery.

(b) Any utility may seek adjustment of the interim stranded cost recovery charge at any time based on severe financial hardship, as determined by the commission. The setting of an interim stranded cost recovery charge shall establish no legal, factual, or policy precedent with respect to the final determination of stranded cost recovery by the commission in any subsequent administrative or judicial proceeding.

VII. The interim stranded cost recovery charge established for a utility as provided in paragraph VI may also be adjusted based upon the outcome of rate case proceedings to adjudicate claims for stranded cost recovery pursuant to paragraph V of this section. Any amounts approved by the commission for stranded cost recovery shall be net of amounts previously collected through interim stranded cost recovery charges.

VIII. (a) The commission is authorized to order such charges and other service provisions and to take such other actions that are necessary to implement restructuring and that are substantially consistent with the principles established in this chapter. The commission is authorized to require that distribution and electricity supply services be provided by separate affiliates.

(b) [Repealed.]

(c) The portion of the system benefits charge due to programs for low-income customers shall not exceed 1.5 mills per kilowatt hour. If the commission determines that the low-income program fund has accumulated an excess of $1,000,000 and that the excess is not likely to be substantially reduced over the next 12 months, it shall suspend collection of some or all of this portion of the system benefits charge for a period of time it deems reasonable.

(d) [Repealed.]

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

(f) Beginning in 2000, the commission shall submit a report to the legislative oversight committee on electric utility restructuring by October 1 of each year. The report shall concern the results and effectiveness of the system benefits charge.

(g) [Repealed.]

VIII-a. Any electric utility that collects funds for energy efficiency programs that are subject to the commission's approval, shall include in its plans to be submitted to the commission program design, and/or enhancements, and estimated participation that maximize energy efficiency benefits to public schools, including measures that help enhance the energy efficiency of public school construction or renovation projects that are designed to improve indoor air quality. The report required under RSA 374-F:4, VIII(f) shall include the results and effectiveness of the energy efficiency programs for schools and, in addition to other requirements, be submitted to the commissioner of the department of education.

IX. An electricity supplier shall be eligible to compete, subject to necessary limitations established by the commission, for open access customers only if affiliated utilities file comparable open access transmission and distribution rates with the FERC or the commission, or both as appropriate, for all of their transmission facilities in New Hampshire and to the extent practicable, all of their distribution facilities in New Hampshire.

X. Nothing in this chapter shall be construed to prohibit the commission from otherwise exercising its lawful authority under title 34, in proceedings which relate to the introduction of competition in the retail electric utility industry including the retention of experts and consultants to assist the commission in its investigations and the assessment of such costs against utilities and any other parties to the proceedings, consistent with RSA 365:37 and RSA 365:38.

XI. Any administrative or adjudicative proceeding or public hearing relating to this chapter shall be subject to the provisions of RSA 541-A.

XII. To the extent that the provisions of this chapter are applicable to rural electric cooperatives for which a certificate of deregulation is on file with the commission, the commission shall exercise its authority with regard to such deregulated rural electric cooperatives only when and to the extent that the commission finds, after notice and hearing, that such action is required to ensure that such deregulated rural electric cooperatives do not act in a manner which is inconsistent with the restructuring policy principles of RSA 374-F:3. The commission shall have the authority to require that such deregulated rural electric cooperatives participate in proceedings, answer commission requests for information and file such reports as may be reasonably necessary to permit the commission to make an informed finding concerning the relevant restructuring policy principle actions of such deregulated rural electric cooperatives. Absent such a finding by the commission, the active role of assuring that the restructuring policy principles are appropriately addressed within their service territories shall be reserved to the deregulated rural electric cooperatives. Notwithstanding the foregoing, deregulated rural electric cooperatives shall be subject to the commission's jurisdiction with regard to those provisions of RSA 374-F pertaining to stranded cost recovery, customer choice, open access tariffs, default service, energy efficiency, and low income programs to the same extent as other public utilities.

Source. 1996, 129:2. 1997, 298:28. 1998, 191:6; 262:2. 1999, 289:6-9. 2000, 249:4. 2001, 29:12. 2002, 212:7. 2004, 164:1. 2005, 102:2; 228:3. 2007, 208:1, eff. Aug. 24, 2007. 2009, 236:3, 4, I-III, eff. July 16, 2009.

Section 374-F:4-a

374-F:4-a Commission Established. – [Repealed 2015, 148:2, eff. Nov. 1, 2015.]

Section 374-F:4-b

374-F:4-b Ratepayer Protection. –

I. Within 60 days of the effective date of this section, the commission shall initiate a proceeding to develop rules to allow residential and small commercial customers to choose how they receive communication from competitive electric suppliers and to implement the provisions of this section.

II. Within 120 days of the effective date of this section, the commission shall redesign its website to enable residential and small commercial customers to compare standard pricing policies and charges and to require competitive electric suppliers to input such information. Such information shall be input no less frequently than once per month, unless there is no change in such information. Such redesign shall:

(a) Reflect the best practices of similar commission websites in other states and develop a process for removal of a competitive electric supplier's listings from such Internet website based on protocols established by the commission to ensure compliance with this section and to address customer complaints.

(b) Emphasize:

(1) Uniformity in the way competitive electric suppliers provide information for each category on the commission's website.

(2) Ease of use by customers.

(3) Ease of selecting and purchasing a specific contract from a competitive electric supplier shown on the commission's website.

(c) Include separate input boxes for the following information:

(1) A link to the provider's web page.

(2) Contract durations.

(3) Whether the contract has variable or fixed rates, or both, and when such rates apply.
(4) Cancellation charges.
(5) Rates.
(6) Other relevant information.

III. On or before July 1, 2017, and every 2 years thereafter, the commission shall review its website and ensure that the site remains an efficient tool for the comparison of pricing policies and charges among competitive electric suppliers.

IV. Unless the contract specifies a month-to-month variable rate, no competitive electric supplier shall charge a residential customer a variable rate, including during a contract term or following the expiration of a contract, without first providing written notification in a form approved by the commission of the nature of such variable rate 45 days prior to the commencement of the variable rate. The residential customer shall select the method of written notification at the time the contract is signed. Such customer shall have the option to change the method of notification at any time during the contract.

V. Competitive electric suppliers shall retain records of any of the notices required in this section for a period of not less than 2 years and shall make such records available to the commission upon its request.

Source. 2015, 268:1, eff. July 20, 2015.

Section 374-F:5

374-F:5 Oversight Committee; Establishment; Report; Meetings. –

I. There is established a legislative oversight committee on electric utility restructuring consisting of 7 members as follows:

(a) Five members of the house, at least 3 of whom shall be members of the science, technology and energy committee, or its successor, and at least one of whom shall be a member of a minority party, appointed by the speaker of the house.

(b) Two members of the senate, at least one of whom shall be a member of the energy and economic development committee, or its successor, and at least one of whom shall be a member of the minority party, appointed by the president of the senate.

II. Committee members shall be appointed to 2-year terms expiring on the first Wednesday of even-numbered years. Members may succeed themselves.

III. The committee shall provide an interim report on or before April 1, and an annual report on or before November 1 to the governor, the speaker of the house, the senate president, the state library, and the public utilities commission on the status of electric utility restructuring, including the status of core energy efficiency programs monitored under RSA 374-F:6.

IV. The committee shall meet quarterly or as often as is necessary to conduct its business. Four members of the committee shall constitute a quorum.

V. Members shall receive mileage when attending to the duties of the committee.

Source. 1996, 129:2. 2001, 86:1, 2. 2008, 27:3, eff. Nov. 1, 2008. 2012, 281:6, eff. Jan. 1, 2013.

Section 374-F:6

374-F:6 Duties. – The committee shall be responsible for the following:

I, II. [Repealed.]

III. Studying implementation issues related to the development of competitive electricity markets, including, but not limited to: the structure, effectiveness, and competitiveness of wholesale and retail electricity markets for New Hampshire; regional cooperation and standards; supply and reliability issues; and opportunities for consumers to monitor prices and alter the amount or timing of their electricity use.

IV. Working on promoting the generation of electricity from renewable energy.

V. Monitoring core energy efficiency programs funded by proceeds from sale of allowances under the regional greenhouse gas initiative program pursuant to RSA 125-O:23, III.

VI. Reviewing state energy efficiency programs under the administration of the public utilities commission to determine what barriers exist to providing all-fuels, comprehensive energy efficiency savings to New Hampshire consumers.

Source. 1996, 129:2. 2001, 86:3. 2002, 268:5, 9, eff. May 18, 2002. 2012, 281:7, eff. Jan. 1, 2013. 2014, 330:3, eff. Oct. 3, 2014.

Section 374-F:7

374-F:7 Competitive Electricity Supplier Requirements. –

I. Competitive energy suppliers are not public utilities pursuant to RSA 362:2, though a competitive energy supplier may seek public utility status from the commission if it so chooses. Notwithstanding a competitive energy supplier's non-utility status, the commission is authorized to establish requirements, excluding price regulation, for competitive electricity suppliers, including registration, registration fees, customer information, disclosure, standards of conduct, and consumer protection and assistance requirements. Unless electing to do so, an electricity supplier that offers or sells at retail to consumers within this state products and services that can lawfully be made available to such consumers by more than one supplier shall not, because of such offers or sales, be deemed to be a public utility as defined by RSA 362:2. These requirements shall be applied in a manner consistent with the restructuring principles of this chapter to promote competition among electricity suppliers.

II. Aggregators of electricity load that do not take ownership of power or other services and do not represent any supplier interest are not public utilities pursuant to RSA 362:2, but shall notify the commission of their intent to do business. Municipalities that aggregate electric power or energy services for their citizens pursuant to RSA 53-E are not public utilities pursuant to RSA 362:2.

III. The commission may assess fines against, revoke the registration of, order the rescission of contracts with residential customers of, order restitution to the residential customers of, and prohibit from doing business in the state any competitive electricity supplier, including any aggregator or broker, which is found to have:

(a) Engaged in any unfair or deceptive acts or practices in the marketing, sale, or solicitation of electricity supply or related services;

(b) Violated the requirements of this section or any other provision of this title applicable to competitive electricity suppliers; or

(c) Violated any rule adopted by the commission pursuant to paragraph V and RSA 374-F:4-b.

IV. As a condition of operation, for a 2-year interim period from the date that competition is implemented in one or more areas of the state, competitive energy suppliers and load aggregators shall submit to the jurisdiction of the commission for mediation and resolution of disputes between customers and competitive energy suppliers or aggregators. Municipalities that aggregate electric power or energy service for their citizens pursuant to RSA 53-E are not subject to this paragraph.

V. The commission shall adopt rules, under RSA 541-A, to implement this section.

Source. 1997, 298:19. 2007, 26:5, eff. July 10, 2007. 2010, 336:2, eff. Oct. 18, 2010. 2015, 268:2, eff. July 20, 2015.

Section 374-F:8

374-F:8 Participation in Regional Activities. – The commission shall advocate for New Hampshire interests before the Federal Energy Regulatory Commission and other regional and federal bodies. The commission shall participate in the activities of the New England Conference of Public Utility Commissioners, the National Association of Regulatory Utility Commissioners, and the New England States Committee on Electricity, or other similar organizations, and work with the New England Independent System Operator and NEPOOL to advance the interests of New Hampshire with respect to wholesale electric issues, including policy goals relating to fuel diversity, renewable energy, and energy efficiency, and to assure nondiscriminatory open access to a safe, adequate, and reliable transmission system at just and reasonable prices.

Source. 2001, 29:7. 2007, 364:2, eff. July 17, 2007.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 378
RATES AND CHARGES

Least Cost Energy Planning

Section 378:37

378:37 New Hampshire Energy Policy. – The general court declares that it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.

Source. 1990, 226:1, eff. Jan. 1, 1991. 2014, 129:1, eff. Aug. 15, 2014.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 378
RATES AND CHARGES

Least Cost Energy Planning

Section 378:38

378:38 Submission of Plans to the Commission. – Pursuant to the policy established under RSA 378:37, each electric and natural gas utility, under RSA 362:2, shall file a least cost integrated resource plan with the commission within 2 years of the commission's final order regarding the utility's prior plan, and in all cases within 5 years of the filing date of the prior plan. Each such plan shall include, but not be limited to, the following, as applicable:

I. A forecast of future demand for the utility's service area.

II. An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs.

III. An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources.

IV. An assessment of distribution and transmission requirements, including an assessment of the benefits and costs of "smart grid" technologies, and the institution or extension of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages, including but not limited to, infrastructure automation and technologies.

V. An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers.

VI. An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.

VII. An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.

Source. 1990, 226:1. 1994, 362:4, eff. June 8, 1994. 2014, 129:1, eff. Aug. 15, 2014. 2015, 89:3, eff. Aug. 4, 2015.

TITLE LV
PROCEEDINGS IN SPECIAL CASES

CHAPTER 541
REHEARINGS AND APPEALS IN CERTAIN CASES

Section 541:6

541:6 Appeal. – Within thirty days after the application for a rehearing is denied, or, if the application is granted, then within thirty days after the decision on such rehearing, the applicant may appeal by petition to the supreme court.

Source. 1913, 145:18. PL 239:4. 1937, 107:17; 133:78. RL 414:6.

THE STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A
EVERSOURCE ENERGY

Docket No. DE 16-___

PETITION FOR APPROVAL OF GAS INFRASTRUCTURE CONTRACT BETWEEN PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY AND ALGONQUIN GAS TRANSMISSION, LLC

Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or "Company"), pursuant to Puc 202.01(a), and Puc 203.06, hereby petitions the New Hampshire Public Utilities Commission ("Commission") for approval of a Precedent Agreement for firm gas transportation and storage services between Eversource and Algonquin Gas Transmission, LLC ("Algonquin" or "AGT") relative to the proposed Access Northeast ("Access Northeast" or "ANE") pipeline project (the "ANE Contract"). Eversource requests that the Commission determine that the ANE Contract is in the public interest and otherwise consistent with New Hampshire law. In support of this petition, Eversource states as follows:

1. In April 2015, the Commission commenced a proceeding, docketed as Docket No. IR 15-124, wherein it recognized that in recent years there has been a sizeable increase in the use of natural gas as a fuel for electric generation while, at the same time, significant constraints exist in relation to the natural gas supply to the New England region. As stated in the order of notice in that proceeding, the natural gas pipeline constraints have led to extreme price volatility in the New England gas markets in the winter months that, in turn, have resulted in sharply higher wholesale electricity prices. Those higher wholesale electricity prices convert directly into high retail electricity prices for New Hampshire customers, particularly in the winter period.

Accordingly, the Commission required that there be a targeted investigation to examine "the gas-resource constraint problem that is affecting New Hampshire's EDCs and electricity consumers." April 17, 2015 Order of Notice in Docket No. IR 15-124 at 3. Further, the Commission directed the Staff to inquire with the New Hampshire electric distribution companies ("EDCs") regarding potential means of addressing these market problems under existing New Hampshire law.

2. On July 10, 2015, the Staff of the Commission issued a legal memorandum in Docket No. IR 15-124. In that memorandum, and while acknowledging that its analysis might adapt to a specific proposal, the Staff concluded, in relevant part, that the EDCs, including Eversource, are authorized under existing New Hampshire law to enter into contracts for natural gas transmission capacity, and to recover the costs of such contracts from electric customers. Written comments on the legal memorandum were submitted on August 10, 2015. In its comments, Eversource stated that its reasoning differed from that of Staff; however, it did agree that EDCs are authorized under existing New Hampshire law to enter into natural gas capacity contracts and to recover the costs of such contracts from electric customers.

3. On September 15, 2015, the Staff issued a report in Docket No. IR 15-124 wherein it noted, among other things, that there is a near universal opinion that "the root cause of the high and volatile winter period wholesale and/or retail electricity prices . . . can be attributed to a wholesale market imbalance of supply and demand for natural gas." September 15, 2015 Staff Report in Docket No. IR 15-124 at 14. On January 19, 2016, the Commission issued Order

No. 25,860 in Docket No. IR 15-124, accepting Staff's report.[1] Although the Commission refrained from making definitive rulings on the legal authority of EDCs to contract for gas capacity, the Commission set out clear guidelines and recommendations for any potential petition for a gas capacity acquisition by a New Hampshire EDC.

4. In recognition of the significant natural gas capacity constraints in New England – constraints that were identified in the Commission's order of notice and confirmed through the Staff's investigation in Docket No. IR 15-124 – and the detrimental impact these constraints have on electricity prices and reliability, Eversource has undertaken deliberate and reasoned steps to improve the reliability and cost of electric supply for its electric retail customers in New Hampshire and herein seeks the Commission's approval of a contract for natural gas storage and transportation that will directly and effectively address those issues.

5. By this submission, Eversource is requesting the Commission's approval of: (1) the ANE Contract, which is a 20-year interstate pipeline transportation and storage contract providing natural gas capacity for use by electric generation facilities in the ISO-NE region; (2) an Electric Reliability Service Program ("ERSP") to set parameters for the release of capacity and the sale of liquefied natural gas ("LNG") supply available by virtue of the ANE Contract; and (3) a Long-Term Gas Transportation and Storage Contract ("LGTSC") tariff, which allows

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[1] A substantially similar review was undertaken in Massachusetts coincident with the review in New Hampshire and was docketed by the Massachusetts Department of Public Utilities ("MDPU") as D.P.U. 15-37. On October 2, 2015, the MDPU issued an order similar to that by the Commission here, concluding in relevant part that EDCs in Massachusetts have the requisite authority to enter into gas capacity contracts and the ability to recover the costs of such contracts from electric customers, subject to meeting various filing requirements as well as MDPU review and approval. Investigation by the Department of Public Utilities on its own Motion into the means by which new natural gas delivery capacity may be added to the New England Market, including actions to be taken by the electric distribution companies, D.P.U. 15-37, at 26-29, 44-47 (2015).

for recovery of costs associated with the ANE Contract.[2] If approved by the Commission, Eversource would release the natural gas capacity to the electric market in accordance with an Algonquin Electric Reliability Service ("ERS") tariff carrying out the terms of the state-approved ERSP. The Algonquin ERS tariff is subject to approval by the Federal Energy Regulatory Commission ("FERC").

6. Algonquin is a wholly owned subsidiary of Spectra Energy Corporation. Spectra Energy Corporation is primarily involved in the transmission of natural gas throughout the United States and Canada. Algonquin operates approximately 1,120 miles of natural gas transmission pipeline in New England with a pipeline capacity of 2.44 Bcf per day. Algonquin's transmission system connects to the Texas Eastern Transmission Company in New Jersey and the Maritimes & Northeast Pipeline ("M&NP") system in the northern region of New England. Algonquin is regulated by FERC under the Natural Gas Act.

7. The ANE project is designed to provide increased natural gas deliverability to the New England region to support electric generation, including most directly, the gas-fired electric generating plants on the Algonquin and M&NP systems. More specifically, the project is designed to provide delivery-point flexibility to serve generators in four separate sub-regions of the market, referred to as Power Plant Aggregation Areas, which include: (1) Connecticut; (2) southeastern Massachusetts and Rhode Island; (3) central and eastern Massachusetts; (4) and Northern New England (including New Hampshire and Maine).

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[2] On December 18, 2015, the Eversource Energy operating affiliates in Massachusetts, NSTAR Electric Company and Western Massachusetts Electric Company, submitted a similar petition in docket D.P.U. 15-181. In January 2016, National Grid submitted a substantially similar petition for contract approval on behalf of its Massachusetts-based operating companies, Massachusetts Electric Company and the Nantucket Electric Company, in a proceeding docketed as D.P.U. 16-05.

8. The ANE project is designed to provide: (1) 500,000 MMBtu/day of indirect access to the gas supplies in the Marcellus Shale region in Northeastern Pennsylvania through Algonquin's existing direct connections to the Millennium Pipeline at Ramapo, NY; the interconnection with Tennessee Gas Pipeline ("Tennessee" or "TGP") at Mahwah, NJ; and the interconnection with Iroquois at Brookfield, CT; and (2) 400,000 MMBtu/day of access to a proposed market-area domestic liquefied natural gas ("LNG") storage facility. The new LNG storage facility in Acushnet, MA will provide storage withdrawal capacity of 400,000 MMBtu/day, liquefaction capability up to 54,000 MMBtu/day, and 6,400,000 MMBtu of LNG storage capacity.[3] In the aggregate, the ANE transportation and storage facilities will provide a total of 900,000 MMBtu/day of firm, incremental, integrated transportation and LNG deliverability to multiple generators; thereby enabling net benefits to electric customers.

9. In accordance with the standards described in both the July 10, 2015 Staff Memorandum at 7-8, and the September 15, 2015 Staff report in Docket No. IR 15-124 at 45-47, as well as in Order No. 25,860 at 4-5, Eversource has undertaken an open and transparent competitive evaluation and selection process to identify the infrastructure alternative with the highest value for New Hampshire electricity customers. This filing for contract approval demonstrates that the proposed ANE Contract will provide the significant value to New Hampshire electricity customers because the agreement: (1) results in net benefits for Eversource customers at a reasonable cost; and (2) compares favorably to the range of alternative options reasonably available to Eversource as a result of the competitive solicitation. If approved, Eversource customers will be the direct beneficiaries of the release of incremental gas-transportation capacity to the market, with price relief and improved reliability expected to result

[3] This is based on total storage capacity of 6,373,592 Mcf, after adjusting for the heel and an assumed BTU content of 1,030 BTU/cubic foot.

from the procurement. Specifically, energy cost savings are projected to exceed the contract costs on a 3/1 ratio, excluding any consideration of capacity-release revenues that will be credited to Eversource customers. The benefits of the capacity made possible through the proposed ANE Contract are significant, sustaining and necessary.

10. In this initial filing, Eversource is providing quantitative and qualitative analyses demonstrating that the price associated with the ANE Contract is competitive and that the proposed ANE Contract satisfies other non-price factors, such as reliability, diversity of supply and the ability to directly serve electric generation facilities having a material impact on electricity prices. These attributes are consistent with the energy policy of the state "to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources." RSA 378:37.

11. To support of the Commission's approval of the ANE Contract proposal, Eversource is submitting the following testimony and related attachments:

- Mr. James G. Daly, Vice President, Energy Supply for Eversource Energy Service Company, providing an overview of the filing and addressing several aspects of the Eversource proposal including the energy-market conditions that are giving rise to the need for incremental interstate gas pipeline transportation and storage services; the net-benefits analysis prepared in relation to the proposed ANE Contract; the process conducted by the Eversource EDCs[4] to identify resource alternatives for addressing pipeline capacity constraints, including the request for proposals ("RFP") process; possible alternatives to the Access Northeast project and the economic and non-economic factors used by the Company to evaluate the Access Northeast project; how Eversource will manage contract quantities and maximize the release revenues received by customers; and the proposed ratemaking mechanism for the costs and revenues attributable to customers.
- Mr. James M. Stephens, of Sussex Economic Advisors, LLC ("Sussex Advisors"), addressing the market and policy factors that influenced the Company's decision to acquire firm natural gas transportation and storage capacity; the process that Eversource followed to confirm that the proposed contracts would provide an appropriate solution to market dynamics that have produced reliability concerns and high electric retail prices;

[4] The "Eversource EDCs" include the Company and the Eversource Massachusetts EDCs.

the terms and operation of the contractual arrangements executed by the Company; and the Company's evaluation and analysis of potential resource alternatives.

- Mr. Kevin R. Petak, of ICF International ("ICF"), sponsoring the report titled, "Access Northeast Project - Reliability Benefits and Energy Cost Savings to New England Consumers," which was prepared in relation to the ANE Contract (the "ICF Report"). The ICF Report focuses on the impact that new infrastructure is expected to have on regional gas and electricity prices, and the associated economic impacts for consumers. The assessment includes an independent evaluation of the electric consumer benefits expected to arise from the lower gas prices available as a result of the proposed ANE project.

- Mr. Tilak Subrahmanian, Energy Efficiency for Eversource Energy Service Company, describing the role that the Company's energy efficiency programs played in the evaluation of alternatives.

- Mr. Christopher J. Goulding, Manager of Revenue Requirements – New Hampshire and Ms. Lois B. Jones, Team Leader – Rates, for Eversource Energy Service Company, explaining the mechanism by which the Company will recover contract-related costs and flow back to customers the net revenues associated with the release of capacity and any associated sale of storage made by the EDC or its Capacity Administrator/Manager. The testimony and attachments also present potential bill impacts for customers relating to the contract costs.

12. The Eversource EDCs jointly issued an RFP with National Grid on October 23, 2015 to six interstate pipeline companies serving the New England region and two LNG providers.[5] The purpose of the RFP was to confirm the range of resource alternatives that would be operationally feasible, commercially reasonable, cost-effective and sufficiently sized to have a significant impact on generation-related reliability and cost concerns. The bid guidelines encompassed threshold criteria, as well as contractual parameters, that would need to be met to be considered a viable solution, including but not limited to criteria related to regional scale, delivery and receipt points, flexible service offerings, price, contract terms and renewal rights, contract/precedent agreements, service agreements/tariffs, experience and expertise, necessary approvals, financial statements/business reports and legal matters/conflicts.

[5] Prior to and during the RFP process and subsequent contract negotiations, Eversource utilized a rigorous process to ensure that contract negotiations were conducted on a transparent, arms-length basis consistent with N.H. Code Admin. Rules Puc 2100.

13. The Eversource EDCs received seven bids on November 13, 2015 encompassing four interstate pipeline companies and three LNG suppliers. The pipelines included Tennessee, Algonquin, Portland Natural Gas Transmission System ("PNGTS") (jointly with TransCanada Corporation ("TransCanada") and Iroquois Gas Transmission ("Iroquois"), and Iroquois separately from TransCanada and PNGTS. The LNG suppliers included Repsol Energy North America ("Repsol"), GDF Suez Energy North America ("GDF SUEZ") and Stolt LNGaz of Canada. Some bidders identified multiple options within their bids resulting in the evaluation of approximately 20 resource alternatives.

14. As described in the testimony, the Eversource EDCs evaluated the bids with the assistance of an unaffiliated third-party, Sussex Advisors, in a three-step process. In the first step, a screening analysis was undertaken to determine whether the respective bid conformed with the requirements and objectives of the RFP. Several bids were eliminated from consideration at this stage due to the fact that the bids were "non-conforming" in terms of satisfying the threshold bid criteria. The projects remaining after the preliminary screening included the Tennessee Northeast Energy Direct ("NED") project; the 600,000 MMBtu/day PNGTS proposal from Wright, NY; several GDF Suez alternatives; the Repsol supply alternative; and the Access Northeast project.

15. The second step of the process involved organizing the bids by the Pipeline Delivery Area served (*i.e.*, Algonquin or Tennessee) and then by category of project (*i.e.*, Pipeline Only, Pipeline with LNG Storage (Hybrid), and Imported LNG). The quantitative analysis performed in this second step of the process by Sussex Advisors was based on a "landed-cost" analysis, as presented by Mr. Stephens in Attachment EVER-JMS-4 (Sussex Landed Cost Analysis).

16. The landed cost analysis was developed as a threshold component of the Company's decision-making process, but is not the sole factor for differentiating the relative benefits of the project proposals or determining resource selection. The overriding objective of the resource procurement is to enter into a contract that will lead to the development of gas transportation and/or storage capacity that will have the greatest potential to improve reliability and reduce prices in the wholesale electric market, *i.e.*, producing the highest value to electricity customers. The qualitative analysis was based on the assessment of certain risk categories including: generation capacity served; peak day deliverability; flexibility; receipt point liquidity; construction risks; sponsor financial consideration; and potential capacity mitigation opportunities. The projects remaining after the second-step analysis included the Tennessee NED project and the Access Northeast project.

17. The third step of the bid evaluation process was a comparative assessment of the Access Northeast project and the Tennessee NED project. The Access Northeast and Tennessee NED projects were each evaluated in relation to their respective capabilities to improve reliability and to have a meaningful impact on wholesale market prices.

18. Sussex Advisors identified the Access Northeast project as the option with the highest capability to impact the reliability and pricing issues affecting the New England region. The Access Northeast project is connected to nearly 70 percent of New England's electric generation capacity that is directly connected to an interstate pipeline. Therefore, the key capabilities of the Access Northeast project that position it to have a major impact on regional reliability and wholesale market prices are that the project: (1) reaches the largest number of directly connected power plants; (2) provides access to liquid supplies of scale and is designed to minimize the need to reach back further to more liquid points with larger demand charges; and

(3) is designed to provide operational flexibility through a market area domestic LNG facility that will support no-notice and fast-start services for electric generators. In addition, Algonquin, as a sponsor of the Access Northeast project, has considerable experience constructing, operating, and expanding natural gas transportation in New England. That experience includes the currently underway Algonquin Incremental Market project and the Atlantic Bridge project, which similarly expand the capacity of the Algonquin system.

19. In accordance with the determination that the Access Northeast project provided the option with the highest capability to impact the reliability and pricing issues affecting the New England region, Eversource negotiated and executed the ANE Contract. The ANE Contract sets forth the rights and obligations of Algonquin and the Company to seek to obtain the necessary corporate and regulatory approvals, and requires the Company and Algonquin to execute a Service Agreement following receipt of those approvals. Copies of the executed precedent agreements and the related service agreement are provided in Attachment EVER-JGD-2 (CONFIDENTIAL).

20. The ANE Contract provides a Maximum Daily Receipt Quantity ("MDRQ") of 37,000 MMBtu/day of capacity and a Maximum Daily Withdrawal Quantity ("MDWQ") of 29,600 MMBtu/day from the LNG storage service, which provides an opportunity to deliver up to a maximum of 66,600 MMBtu/day of gas to New England generators. The contract quantities were determined through a computation of New England load share and represent the load share served by the Company within the load served by investor-owned EDCs in New England.

21. The proposed ANE Contract provides a 20-year term beginning on the in-service date of the first of four planned phases of the Access Northeast project. The project is scheduled to go into service beginning with the first phase starting on November 1, 2018; the second Phase

starting on November 1 2019, the third phase commencing on November 1, 2020; and the fourth and final phase commencing on May 1, 2021. Eversource and the other EDC customers for the Access Northeast project have negotiated a levelized cost for the 20-year duration of the contract. The rate paid by the EDCs will be based on the actual cost of construction subject to a cap. The ANE Contract also contains provisions related to costs and cost caps, regulatory approvals, right of first refusal and discounts for contract extensions and most-favored-nation status.

22. To maximize the value of the ANE Contract for customers, the Eversource EDCs collaborated with National Grid to develop the ERSP. The ERSP will utilize a Capacity Manager, to be selected following a competitive bidding process, to administer the release of the contracted gas capacity to the market. The Capacity Manager's responsibilities would include releasing the capacity in a manner consistent with the EDC guidelines, and reporting on results, with compensation paid to the Capacity Manager in the form of a fixed fee. The Capacity Manager will not be allowed to have any conflicts of interest that could distract or conflict with its requirement to provide value for the EDC retail electric customers, which include effectively releasing capacity to the generators to ensure reliability and maximizing the credits received from the releases of capacity to help offset the cost of the EDC capacity.

23. The ICF Report developed for the Eversource EDCs and included with this filing demonstrates that Access Northeast would generate significant cost savings to New England electric consumers by reducing the price of natural gas delivered to New England power generators, and subsequently, wholesale energy prices in all New England states. ICF estimates wholesale power price reductions of up to \$12/MWh, with the total cost of the Access Northeast project equating to \$4/MWh and net savings for customers of approximately \$8/MWh. Taking

into account the cost of the pipeline, the net benefits to New England electric consumers could range from $0.9 to $1.3 billion per year on average, under normal weather conditions with capacity-release and LNG sales revenues only increasing that count.

24. In addition to the analyses supporting the ANE Contract, Eversource has included a mechanism for cost recovery and crediting of net release revenues. The mechanism is designed to net costs against expected revenues so that customers are charged a net cost that is recovered from all customers through a uniform per kWh rate. The cost elements of the ANE Contract include: (1) fixed and variable transportation charges; (2) storage inventory costs and injection and withdrawal charges; and (3) administration charges, which would encompass fixed fees paid to the Capacity Manager and consulting fees or other similar costs incurred by participating EDCs to effectuate and manage the contracts. Revenues offsetting those costs would be obtained from capacity releases and sales from LNG inventory.

25. The Company's initial filing discusses the additional regulatory approvals that are necessary for the Access Northeast project to move forward. Specifically companies engaged in the interstate transportation and storage of natural gas in interstate commerce must receive a "Certificate of Need and Public Necessity" from FERC to construct a major project. FERC is directly involved in evaluation the costs of the projects; the rates to be charged by the sponsor; and compliance with FERC regulations. The U.S. Department of Transportation is involved in safety issues. A specific FERC concern is that the project must be supported by long-term contracts and not involve subsidies from other pipeline customers. Therefore, like other interstate pipeline projects, Access Northeast will require state-approved, long-term contracts as a prerequisite for its FERC approvals.

26. For this reason, New England states other than New Hampshire must also approve contracts relating to the Access Northeast project. At this point, all New England states except Vermont have laws or regulations in place, or proposed, that allow for the development of natural gas infrastructure to serve power generation. Consistent with the established regulatory structures, efforts are underway in each of the six states to consider participation and support for infrastructure contracts that will alleviate reliability and cost concerns for New England's retail electric customers. As noted, Eversource operating affiliates are currently seeking state regulatory approval in Massachusetts for ANE contracts equal to the load share served by NSTAR Electric Company and Western Massachusetts Electric Company. In Connecticut, the Department of Energy and Environmental Protection is expected to conduct an RFP and direct the EDCs, including the Connecticut Light and Power Company, to enter into precedent agreements for gas transportation capacity.

27. The Access Northeast project is sized as a regional solution and will require other New England states to take responsibility for a proportional share of the costs of the project, which are necessary to achieve the benefits of lower electricity rates and increased reliability across the New England region. Even with the Commission's approval of the proposed ANE Contract, Access Northeast will require sufficient subscription (*i.e.*, a total of 900,000 MMBtu/day), evidenced through the execution of long-term contracts by EDCs operating throughout New England. If other approvals do not follow in one or more New England states, AGT will need to make a determination whether to proceed with fewer precedent agreements; to reconfigure the project and renegotiate the existing precedent agreements; or terminate the project. Given the significant benefits available to New Hampshire customers as a result of

project implementation, it will be important for New Hampshire to monitor developments and allow for adaptations and adjustments to achieve project implementation.

28. The proposed contract may be approved by the Commission and within its legal authority because, as discussed in the legal memoranda filed in Docket No. IR 15-124, as well as the Staff report: (1) the Company's participation in the ANE Contract does not violate the Restructuring Principles of RSA Chapter 374-F; (2) the corporate powers granted to Eversource by RSA Chapter 374-A appear to encompass and authorize such contract execution; (3) the exercise of Commission authority is in the public interest under RSA 374:57; (4) participating in a contract designed to improve regional and state electric reliability is consistent with the planning principles set out RSA 378:37 and :38 as well as the New Hampshire 10-Year State Energy Strategy; and (5) cost recovery through rates charged to customers is allowed by and consistent with New Hampshire law, including RSA 374:57 and the provisions of RSA Chapter 374-A, as well as the Commission's plenary authority with respect to utility rates.

29. To achieve the public-interest objectives served by the ANE Contract, it is necessary to facilitate the timely construction of the Access Northeast project. Therefore, Eversource respectfully requests a decision from the Commission approving the proposed ANE Contract and related mechanisms by October 1, 2016.

WHEREFORE, Eversource respectfully requests that the Commission:

A. Find that the 20-year transportation and storage contract between the Company and AGT on the proposed "Access Northeast" project is in the public interest and will provide net benefits at a reasonable cost to Eversource customers in the form of lower electric retail prices;

B. Find that the proposed Electric Reliability Service Program set forth in Attachment EVER-JGD-5 is reasonably structured to govern the release capacity and sale of LNG supply furthering the program objectives;

C. Find that the Long-Term Gas Transportation and Storage Contract tariff would properly allow for recovery of costs associated with agreements executed by PSNH for the provision of interstate pipeline transportation and gas storage services to electric generation facilities in the ISO-NE region; and

D. Order such further relief as may be just and reasonable and necessary to approve the contract proposed herein.

Respectfully submitted this 18th day of February, 2016.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

By:__________________________________

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EXECUTION COPY

PRECEDENT AGREEMENT

This PRECEDENT AGREEMENT ("Precedent Agreement") is made and entered into this ___ day of February, 2016 ("Effective Date"), by and between Algonquin Gas Transmission, LLC ("Pipeline"), a Delaware limited liability company, and Public Service Company of New Hampshire d/b/a Eversource Energy, a New Hampshire corporation ("Customer"). Pipeline and Customer are sometimes referred to individually as a "Party" and collectively as the "Parties."

W I T N E S S E T H:

WHEREAS, Pipeline owns and operates an interstate natural gas transmission system in the Northeastern United States;

WHEREAS, Customer desires that Pipeline expand such interstate natural gas transmission system and use the resulting capacity to enhance New England's electric reliability and energy competitiveness in connection with the Access Northeast Project, the details of which were publicly announced on September 16, 2014 (the "Project");

WHEREAS, Pipeline is proposing to implement a new Rate Schedule ERS, substantially in the form attached as Attachment A-1 hereto, for firm transportation of natural gas that is supported by a new liquefied natural gas facility to be located in Acushnet, Massachusetts ("Acushnet Facility"), in connection with Project, and will file Rate Schedule ERS with the Federal Energy Regulatory Commission ("Commission" or "FERC") for approval;

WHEREAS, subject to the terms and conditions of this Precedent Agreement, Pipeline is proposing to construct, own and operate facilities necessary to provide firm transportation entitlements under Rate Schedule ERS in aggregate of 900,000 Dth/d for electric distribution companies, supported by storage capacity of 6,400,000 Dth, vaporization entitlements of 400,000

EXECUTION COPY

Dth/d, and liquefaction entitlements of 54,000 Dth/d of natural gas, in connection with the Project;

WHEREAS, subject to the terms and conditions of this Precedent Agreement, Pipeline is willing to construct the Project and provide the firm transportation service that Customer desires;

NOW, THEREFORE, in consideration of the mutual covenants herein assumed, and intending to be legally bound, Pipeline and Customer agree as follows:

1) Pipeline Obligations. Subject to the terms and conditions of this Precedent Agreement, Pipeline shall proceed with due diligence to obtain from all governmental and regulatory authorities having competent jurisdiction over the premises, including, but not limited to, the Commission, the authorizations and/or exemptions Pipeline determines are necessary: (i) for Pipeline to construct, install, own, operate, and maintain the Project facilities, and, if applicable, abandon existing facilities, necessary to provide the firm transportation service contemplated herein, for Pipeline to implement Rate Schedule ERS and any additional conforming tariff revisions, and include such rate schedule as part of its FERC Gas Tariff and for Pipeline to implement an amendment to the capacity release provisions in its FERC Gas Tariff to establish a process for a customer to release firm capacity to electric generators on a priority basis pursuant to state-approved programs ("Capacity Release Tariff Amendment") (collectively, "Pipeline's Authorizations"); and (ii) for Pipeline to perform its obligations as contemplated in this Precedent Agreement. Pipeline reserves the right to file and prosecute any and all applications for such authorizations, any supplements or amendments thereto, and, if necessary, any request for rehearing or court review, that are consistent with this Precedent Agreement, the Service Agreement as defined in Paragraph 3(a), and the Negotiated Rate Agreement as defined in Paragraph 3(b), in a manner it deems to be in its

best interest. Pipeline agrees to provide Customer with an opportunity to review and comment on the text of Pipeline's application for a certificate of public convenience and necessity for the Project, and Exhibits K and P to such application, to be provided to Customer at least five (5) business days in advance of the filing date and shall in good faith work with Customer to address any concerns raised by Customer with respect to such application. Pipeline agrees to promptly notify Customer in writing when each of Pipeline's Authorizations is received, obtained, rejected or denied. Pipeline shall also promptly notify Customer in writing as to whether each of Pipeline's Authorizations that has been received or obtained is acceptable to Pipeline. During the term of this Precedent Agreement, Pipeline also agrees to use reasonable efforts to support and cooperate with, and to not oppose, obstruct or otherwise interfere with, Customer in Customer's efforts to obtain Customer Authorizations as referenced below. In the event that any necessary FERC authorization or approval for the Capacity Release Tariff Amendment is not received by Pipeline by October 1, 2016, Pipeline shall have the right to terminate this Precedent Agreement. Pipeline's termination right pursuant to this Paragraph 1 expires if it is not exercised within ten (10) days after October 1, 2016. The term of the Precedent Agreement will commence on the Effective Date and continue until the Precedent Agreement is terminated pursuant to Paragraphs 9, 10 or 11 hereof.

2) <u>Customer Obligations.</u>

   a) Subject to the terms and conditions of this Precedent Agreement, Customer shall proceed with due diligence to obtain all necessary and appropriate authorizations and approvals from governmental and regulatory authorities having jurisdiction over the premises, the Customer or the Customer's cost recovery including, but not limited to, such authorizations and approvals for Customer to perform its obligations as contemplated in this Precedent Agreement, the Service Agreement (defined below), and the Negotiated Rate Agreement (defined below) and to recover the costs associated therewith ("Customer Authorizations"). On or before April 1, 2016, the Parties will meet to review the status of the necessary governmental or regulatory authorizations or approvals of all customers listed on Attachment B hereto, including, with respect to Customer, any Customer Authorizations, but excluding any Pipeline's Authorizations.

b) Customer reserves the right to file and prosecute applications for Customer Authorizations, and, if necessary, any court review, in a manner it deems to be in its best interest. Customer agrees to promptly notify Pipeline in writing when each of Customer Authorizations is received, obtained, rejected or denied. Customer shall also promptly notify Pipeline in writing as to whether each of Customer Authorizations that has been received or obtained is acceptable to Customer. All Customer Authorizations must be issued in a form acceptable to Customer.

c) For so long as the Customer Authorizations have not been received and accepted by Customer, Customer shall coordinate with Pipeline regarding the status of the Customer Authorizations on a monthly basis.

d) During the term of this Precedent Agreement, Customer agrees to use reasonable efforts to support and cooperate with, and to not oppose, obstruct or otherwise interfere with the efforts of Pipeline to obtain Pipeline's Authorizations, to provide the firm transportation service contemplated in this Precedent Agreement, and to perform its other obligations as contemplated by this Precedent Agreement. Nothing herein shall be construed to limit or waive Customer's rights to intervene or protest any filing by Pipeline to the extent Customer determines in good faith that such filing is not consistent with Pipeline's obligations or Customer's rights under this Precedent Agreement, the Service Agreement or the Negotiated Rate Agreement. Notwithstanding the foregoing, Customer agrees to intervene in the FERC proceeding established to consider the Capacity Release Tariff Amendment and to file comments with FERC in support of such filing to the extent such filing is consistent with this Precedent Agreement, the Service Agreement as defined in Paragraph 3(a), and the Negotiated Rate Agreement as defined in Paragraph 3(b). Pipeline shall provide notice to Customer of Pipeline's filing of the Capacity Release Tariff Amendment with the FERC.

3) <u>Service Agreement.</u>

a) To effectuate the firm transportation service contemplated herein, Customer and Pipeline agree that no later than twenty five (25) days following the date on which the Commission issues an order granting Pipeline a certificate of public convenience and necessity to construct the Project facilities or, upon Pipeline's request to Customer, within a shorter time following the issuance of such certificate as may be deemed necessary by Pipeline in its reasonable discretion to allow Pipeline to commence the construction of the Project, Pipeline and Customer will execute a firm transportation service agreement under Rate Schedule ERS in the form attached as Attachment A-2 hereto ("Service Agreement"), which:

i) specifies an initial Maximum Daily Transportation Quantity ("MDTQ") of [redacted] to be in effect on the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date, Phase 3 Service Commencement Date, Phase 4 Service Commencement Date, respectively (each as determined in accordance with Paragraph 4 of this Precedent Agreement);

ii) specifies an initial Maximum Storage Quantity ("MSQ") equal to [redacted] to be effective on the Phase 4 Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement);

iii) specifies a primary term ("Primary Term") of twenty (20) years commencing on the Phase 1 Service Commencement Date, as defined below;

iv) specifies the following Non-Storage Primary Point(s) of Receipt and Maximum Daily Receipt Obligation(s) ("MDRO"):

(1) Mahwah (Meter No. 00201) with an MDRO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement), [redacted] to be in effect on the Phase 2 Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement) and [redacted] to be in effect on the Phase 3 Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement);

(2) Ramapo (Meter No. 00214) with an MDRO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date and [redacted] to be in effect on the Phase 3 Service Commencement Date;

(3) Brookfield (Meter No. 00251) with an MDRO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date and [redacted] to be in effect on the Phase 3 Service Commencement Date (collectively "Non-Storage Primary Points of Receipt") provided, however, the sum of the MDROs at all Non-Storage Primary Points of Receipt contemplated in this clause 3(a)(iv) on any day shall not exceed Customer's MDTQ in effect on such date following the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date and Phase 3 Service Commencement Date, and [redacted] following the Phase 4 Service Commencement Date;

v) specifies a Storage Primary Point of Receipt from storage to be effective on the Phase [redacted] Service Commencement Date at Acushnet (Meter No. [TBD]) with an MDRO equal to [redacted]

vi) specifies the following Aggregation Areas with access to Primary Points of Delivery shown on Attachment G:

(1) Connecticut with a Maximum Daily Delivery Obligation ("MDDO") equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement

Date, [redacted] to be in effect on the Phase 3 Service Commencement Date, and [redacted] to be in effect on the Phase 4 Service Commencement Date;

(2) Massachusetts with an MDDO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date, [redacted] to be in effect on the Phase 3 Service Commencement Date, and [redacted] to be in effect on the Phase 4 Service Commencement Date;

(3) SEMA – G System with an MDDO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date, [redacted] to be in effect on the Phase 3 Service Commencement Date, and [redacted] to be in effect on the Phase 4 Service Commencement Date; and

(4) Maine with an MDDO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date, [redacted] to be in effect on the Phase 3 Service Commencement Date, and [redacted] to be in effect on the Phase 4 Service Commencement Date;

provided, however, the sum of the MDDOs at all Primary Point(s) of Delivery contemplated in this clause 3(a)(vi) on any day shall not exceed Customer's MDTQ in effect on such date; and

vii) specifies a Maximum Daily Injection Quantity ("MDIQ") equal to [redacted] to be effective on the Phase [redacted] Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement);

viii) specifies a Maximum Daily Withdrawal Quantity ("MDWQ") equal to [redacted] to be effective on the Phase [redacted] Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement);

ix) incorporates creditworthiness provisions set forth in this Precedent Agreement.

The Customer's MDTQ and MSQ shall be subject to adjustment to the extent necessary to comply with applicable state law, regulation or order (including, without limitation, Customer's Authorizations), and further by agreement of the Parties as described below.

The Aggregate EDC Capacity shall be 900,000 Dth/d, with [redacted] available on the Phase 1 Service Commencement Date, an additional [redacted] available on the

Phase 2 Service Commencement Date, an additional [redacted] available on the Phase 3 Service Commencement Date, and an additional [redacted] available on the Phase 4 Service Commencement Date. On or before [redacted], Pipeline will provide notice to Customer of the status of the Aggregate EDC Capacity for which Pipeline has firm commitments. [redacted]

[redacted] Notwithstanding the foregoing, in the event that an interim storage option will be available after the Phase 1 Service Commencement Date (as defined below) but prior to the Phase 4 Service Commencement Date (as defined below), then Customer shall have the right, but not the obligation, to take Customer's Proportionate Share of such interim storage service on the terms set forth in this Precedent Agreement, the Service Agreement and the Negotiated Rate Agreement until the Phase 4 Service Commencement Date. If Customer exercises its right to such available interim storage service and quantities and such service and quantities will be provided for one (1) year or more, Pipeline and Customer may amend this Precedent Agreement, the Service Agreement and the Negotiated Rate Agreement (as defined below) to provide for service from such interim storage option with comparable volume and rate provisions until the Phase 4 Service Commencement Date subject to the Customer's receipt of necessary regulatory approvals. Pipeline will accept its FERC certificate of public convenience and necessity to construct the Project facilities no later than five (5) days after the execution of the Service Agreement between Pipeline and Customer.

b) Rate. Pipeline and Customer further agree that, contemporaneously with the execution of this Precedent Agreement, they will execute, in accordance with Section 46 of the General Terms and Conditions ("GT&C") of Pipeline's Tariff, a negotiated rate agreement ("Negotiated Rate Agreement"), as set forth on Attachment C hereto, consistent with the terms of this Precedent Agreement which shall become effective on the Phase 1 Service Commencement Date and shall provide for a negotiated rate applicable to service under the Service Agreement, subject to approval by the

Commission. In accordance with and subject to the terms of the Negotiated Rate Agreement, Pipeline may adjust the negotiated rate to reflect any increase or decrease in the actual Project capital costs.

c) Primary Term Extension. [redacted]

d) Renewal. The Primary Term or Primary Term Extension, as applicable, will automatically extend for annual periods at the same MDTQ, MSQ, MDROs, MDDOs, MDIQ and MDWQ unless terminated in accordance with this Paragraph 3(d). Either Party may terminate at the end of the Primary Term, Primary Term Extension [redacted] provided that in the event Customer elects to extend the Primary Term pursuant to

Paragraph 3(c) but subsequently revokes such election, Customer may terminate at the end of the Primary Term by providing notice to Pipeline within sixty (60) days after the date that is three (3) years prior to the end of the Primary Term. The applicable rates during the term of such renewal shall be the rates set forth in the Negotiated Rate Agreement, if applicable.

e) Right of First Refusal. Upon Pipeline's termination of the Service Agreement at the end of the Primary Term, Primary Term Extension or annual renewal terms as contemplated by Paragraph 3(d) of this Precedent Agreement, Customer shall have a Right of First Refusal pursuant to Pipeline's Tariff to be applicable to all of the Customer's MDTQ and MSQ, exercisable in accordance with the notice and other applicable provisions of the Tariff.

f) Most Favored Nation Right. Customer shall have a Most Favored Nation Right as set forth in the Negotiated Rate Agreement. All electric distribution companies that are Project customers shall have the same, or substantially similar, material terms and conditions as contained in this Precedent Agreement, the Service Agreement or the Negotiated Rate Agreement.

4) Commencement of Service.

a) Phase 1 Service Commencement Date. Upon satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the service included in Phase 1, Pipeline shall notify Customer of such fact, and that service under the Service Agreement for such Phase 1 service will commence on a date certain, which date will be the later of: (i) November 1, 2018 and (ii) the date that all of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement are satisfied or waived with respect to Phase 1 ("Phase 1 Service Commencement Date").

b) Phase 2 Service Commencement Date. Upon satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the service included in Phase 2, Pipeline shall notify Customer of such fact, and that service under the Service Agreement for such Phase 2 service will commence on a date certain, which date will be the later of: (i) November 1, 2019 and (ii) the date that all of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement are satisfied or waived with respect to Phase 2 ("Phase 2 Service Commencement Date"); provided that, in the event that the Phase 1 Service Commencement Date has occurred and Customer provides notice of termination pursuant to 9(b) based on the failure of the Phase 2 Service Commencement Date to occur by the date specified in Paragraph 9(b), Pipeline may, within five (5) business days, provide notice to Customer of the satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the Phase 2 service, including service that does not include any storage rights, and that service under the Service Agreement for such portion of Phase 2 service will commence on a date certain, which date will be the first day of the month that is no earlier than fifteen (15) days after the date of such notice ("Phase 2 Partial Service Commencement Date").

c) Phase 3 Service Commencement Date. Upon satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the service included in Phase 3, Pipeline shall notify Customer of such fact, and that service under the Service Agreement for such Phase 3 service will commence on a date certain, which date will be the later of: (i) November 1, 2020 and (ii) the date that all of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement are satisfied or waived with respect to Phase 3 ("Phase 3 Service Commencement Date"); provided that, in the event that the Phase 1 Service Commencement Date and Phase 2 Service Commencement Date have occurred and Customer provides notice of termination pursuant to 9(b) based on the failure of the Phase 3 Service Commencement Date to occur by the date specified in Paragraph 9(b), Pipeline may, within five (5) business days, provide notice to Customer of the satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the Phase 3 service, including service that does not include any storage rights, and that service under the Service Agreement for such portion of Phase 3 service will commence on a date certain, which date will be the first day of the month that is no earlier than fifteen (15) days after the date of such notice ("Phase 3 Partial Service Commencement Date").

d) <u>Phase 4 Service Commencement Date</u>. Upon satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the service included in Phase 4, Pipeline shall notify Customer of such fact, and that service under the Service Agreement for such Phase 4 service will commence on a date certain, which date will be the later of: (i) May 1, 2021 and (ii) the date that all of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement are satisfied or waived with respect to Phase 4 ("Phase 4 Service Commencement Date"); provided that, in the event that the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date and Phase 3 Service Commencement Date have occurred and Customer provides notice of termination pursuant to 9(b) based on the failure of the

Phase 4 Service Commencement Date to occur by the date specified in Paragraph 9(b), Pipeline may, within five (5) business days, provide notice to Customer of the satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the Phase 4 service, including service that does not include any storage rights, and that service under the Service Agreement for such portion of Phase 4 service will commence on a date certain, which date will be the first day of the month that is no earlier than fifteen (15) days after the date of such notice ("Phase 4 Partial Service Commencement Date," and together with the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date, Phase 2 Partial Service Commencement Date, Phase 3 Service Commencement Date, Phase 3 Partial Service Commencement Date, and Phase 4 Service Commencement Date, each a "Service Commencement Date" and, collectively, "Service Commencement Dates").

e) Under no circumstances shall the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date, Phase 3 Service Commencement Date, and Phase 4 Service Commencement Date be later than [redacted] respectively, unless otherwise agreed in writing by both Parties. On and after the date on which Pipeline has notified Customer that service under the Service Agreement will commence for each phase, Pipeline shall provide firm service under Rate Schedule ERS for Customer for such phase pursuant to the terms of the Service Agreement and Customer will pay Pipeline for all applicable charges required by the Service Agreement and the Negotiated Rate Agreement for such phase. The Parties shall amend the Service Agreement to the extent required to implement Paragraph 4 of this Precedent Agreement.

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5) <u>Design and Permitting of Project Facilities.</u> Pipeline will undertake with due diligence the design of the Project facilities and any other preparatory actions necessary for Pipeline to complete and file its application(s) related to the Project with the Commission or other governmental authority as appropriate. Prior to satisfaction of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement, Pipeline shall have the right, but not the obligation (subject to Paragraph 6 of this Precedent Agreement), to proceed with the necessary design of facilities, acquisition of materials, supplies, properties, rights-of-way and any other necessary preparations to implement the firm transportation service under the Service Agreement as contemplated in this Precedent Agreement.

6) <u>Construction of Project.</u> Upon satisfaction of the conditions precedent set forth in Paragraphs 7(a)(i) through 7(a)(iv), inclusive, 7(a)(vi) and 7(b)(i) through 7(b)(iii), inclusive, of this Precedent Agreement, or waiver of the same by Pipeline or Customer, as applicable, and the Parties' execution of the Service Agreement, Pipeline shall proceed (subject to the continuing commitments of substantially all customers executing precedent agreements and service agreements for service utilizing the firm transportation capacity to be made available by the Project) with due diligence to construct the authorized Project facilities in phases and to implement the firm transportation service contemplated in this Precedent Agreement for Phase 1 on November 1, 2018, Phase 2 on November 1, 2019, Phase 3 on November 1, 2020, and Phase 4 on May 1, 2021. If, notwithstanding Pipeline's due diligence, Pipeline is unable to commence the firm transportation service for Customer as contemplated herein for Phase 1 on November 1, 2018, Phase 2 on November 1, 2019, Phase 3 on November 1, 2020, or Phase 4 on May 1, 2021, Pipeline will continue to proceed with due diligence to complete arrangements for such firm transportation service, and commence the firm transportation

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service for Customer for any such phase at the earliest practicable date thereafter. Pipeline will neither be liable nor will this Precedent Agreement or the Service Agreement be subject to cancellation if Pipeline is unable to complete construction of such authorized Project facilities and commence the firm transportation service contemplated herein for Phase 1 by November 1, 2018, Phase 2 by November 1, 2019, or Phase 3 by November 1, 2020, or Phase 4 by May 1, 2021, subject to Customer's rights in Paragraph 9(b) of this Precedent Agreement.

7) Conditions Precedent. Commencement of service under the Service Agreement and Pipeline's and Customer's rights and obligations under the Service Agreement are expressly made subject to satisfaction of the following conditions precedent in this Paragraph 7 (only Pipeline shall have the right to waive the conditions precedent set forth in Paragraph 7(a) and only Customer shall have the right to waive the conditions precedent set forth in Paragraph 7(b)):

a) Pipeline's Conditions Precedent.

i) Pipeline's receipt and acceptance by June 1, 2021, of (i) all necessary certificates and authorizations from the Commission to construct, install, own, operate, and maintain the Project facilities, and, if applicable, abandon existing facilities, all as described in Pipeline's certificate application as it may be amended from time to time, to provide the firm transportation service contemplated herein and in the Service Agreement, and to perform its other obligations contemplated herein, and (ii) an order from the Commission approving or accepting the Capacity Release Tariff Amendment;

ii) Pipeline's receipt of approval, on or before the date the Pipeline files its certificate application with the Commission, from its Board of Directors, or similar governing body, to expend the capital necessary to construct the Project facilities and/or to execute the Service Agreement;

iii) Pipeline's receipt, on or before [redacted] of all necessary governmental authorizations, approvals, and permits required to implement Rate Schedule ERS and include such rate schedule as part of its FERC Gas Tariff, and to construct the Project facilities necessary to provide the firm transportation service contemplated herein and in the Service Agreement other than those specified in Paragraph 7(a)(i);

iv) Pipeline's procurement, on or before [redacted] of all rights-of-way, easements or permits (in form and substance acceptable to Pipeline) necessary for the construction and operation of the Project facilities;

v) Pipeline's completion of construction of the Project facilities and all other facilities required to render firm transportation service for Customer pursuant to the Service Agreement for the applicable phase and Pipeline being ready and able to place such facilities into gas service at the full MDTQ and/or MSQ for such phase on or before [redacted] for Phase 1, [redacted] for Phase 2, [redacted] for Phase 3, and [redacted] for Phase 4; and

vi) Customer's receipt and acceptance by October 1, 2016, of Customer Authorizations identified in accordance with Paragraph 2 of this Precedent Agreement, which Customer Authorizations are acceptable to Pipeline.

b) <u>Customer's Conditions Precedent.</u>

i) Customer's receipt of approval, on or before March 1, 2016, from its Board of Directors, or similar governing body, to participate in the Project;

ii) Customer's receipt and acceptance by October 1, 2016, of Customer Authorizations in a final and non-appealable form acceptable to Customer; and

iii) Pipeline's receipt by December 1, 2020, of (i) a certificate from the Commission authorizing Pipeline to construct, install, own, operate, and maintain the Project facilities, and, if applicable, abandon existing facilities, all as described in Pipeline's certificate application as it may be amended from time to time, to provide the firm transportation service contemplated herein and in the Service Agreement, and to perform its other obligations contemplated herein; and (ii) an order from the Commission approving or accepting the Capacity Release Tariff Amendment.

c) With respect to each condition precedent set forth in Paragraph 7(a) of this Precedent Agreement, Pipeline shall use commercially reasonable efforts to provide notice to Customer within five (5) days of the date that such condition precedent has been satisfied or waived. With respect to the conditions precedent set forth in Paragraphs 7(b)(i) and (ii) of this Precedent Agreement, Customer shall use commercially reasonable efforts to provide notice to Pipeline within five (5) days of the date that such condition precedent has been satisfied or waived. The failure of either Pipeline or Customer to notify the other as contemplated by this Paragraph 7(c) shall not be considered a breach of this Precedent Agreement nor shall it be considered cause for either Party to terminate this Precedent Agreement. [redacted]

d) Unless otherwise provided for herein, Pipeline's Authorizations contemplated in

Paragraph 1 of this Precedent Agreement and otherwise associated with the firm transportation service contemplated by this Precedent Agreement must be issued in form and substance reasonably satisfactory to both Parties hereto; provided that this Paragraph 7(d) does not give rise to a termination right for Pipeline independent of Pipeline's termination right pursuant to Paragraph 9(a). Pipeline shall provide written notice to Customer not later than ten (10) days after issuance of any of Pipeline's Authorizations, and shall offer to meet with Customer promptly upon the issuance of any such authorization(s) not issued or granted in form and substance as requested to discuss concerns or issues related thereto. For purposes of this Precedent Agreement, Pipeline's Authorizations shall be deemed satisfactory to Customer if such Authorizations are consistent with the terms of this Precedent Agreement, the Service Agreement, the Negotiated Rate Agreement, and the Customer's Authorizations, and do not impose conditions or obligations that substantially and adversely affect Customer. To the extent Customer determines in Customer's sole and reasonable judgment that the Pipeline's Authorizations do not satisfy the requirements of the immediately preceding sentence, Customer shall notify Pipeline in writing not later than ten (10) days after receipt of Pipeline's notice of such Authorizations, and shall detail the basis of such determination. Designated representatives for the Parties shall meet promptly and negotiate in good faith to reach mutual agreement on a reasonable modification or an agreeable alternative to address such substantial and adverse effect(s), and each Party agrees to discuss in good faith any positions advanced by the other Party in accordance with the foregoing. All other governmental authorizations, approvals, permits and/or exemptions that Pipeline must obtain must be issued in form and substance reasonably acceptable to Pipeline. All

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governmental approvals that Pipeline is required by this Precedent Agreement to obtain must be duly granted by the Commission or other governmental agency or authority having jurisdiction, and must be final and no longer subject to rehearing or appeal; provided, however, Pipeline may waive the requirement that such authorization(s) and approval(s) be final and no longer subject to rehearing or appeal. Pipeline shall provide quarterly updates to Customer regarding Pipeline's progress in obtaining Pipeline's Authorizations.

8. Limitation of Liability. NOTWITHSTANDING THE FOREGOING, THE PARTIES HERETO AGREE THAT NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR ANY PUNITIVE, SPECIAL, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES (INCLUDING, WITHOUT LIMITATION, LOSS OF PROFITS OR BUSINESS INTERRUPTIONS) ARISING OUT OF OR IN ANY MANNER RELATED TO THIS PRECEDENT AGREEMENT, AND WITHOUT REGARD TO THE CAUSE OR CAUSES THEREOF OR THE SOLE, CONCURRENT OR CONTRIBUTORY NEGLIGENCE (WHETHER ACTIVE OR PASSIVE), STRICT LIABILITY (INCLUDING, WITHOUT LIMITATION, STRICT STATUTORY LIABILITY AND STRICT LIABILITY IN TORT) OR OTHER FAULT OF EITHER PARTY. THE IMMEDIATELY PRECEDING SENTENCE SPECIFICALLY PROTECTS EACH PARTY AGAINST SUCH PUNITIVE, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES EVEN IF RELATED TO THE NEGLIGENCE, GROSS NEGLIGENCE, WILLFUL MISCONDUCT, STRICT LIABILITY OR OTHER FAULT OR RESPONSIBILITY OF SUCH PARTY; AND ALL RIGHTS TO RECOVER SUCH DAMAGES OR PROFITS ARE HEREBY

WAIVED AND RELEASED.

9. Termination of Precedent Agreement for Failure of Conditions Precedent.

a) If the conditions precedent set forth in Paragraph 7(a) of this Precedent Agreement have not been fully satisfied or waived by Pipeline by the applicable dates specified therein or the Service Commencement Dates have not occurred by [redacted] and this Precedent Agreement has not been terminated pursuant to Paragraphs 9(b), 10 or 11 hereof, then Pipeline may thereafter terminate this Precedent Agreement (and the Service Agreement, if executed), with respect to all phases of service for which the Service Commencement Date has not occurred, by providing thirty (30) days' prior written notice of its intention to terminate to Customer; provided, however, if the conditions precedent are satisfied, or waived by Pipeline within such thirty (30) day notice period, then termination of such agreements will not be effective. Pipeline's termination right pursuant to this Paragraph 9(a) expires if it is not exercised within ten (10) days after the deadline giving rise to such termination right. A termination pursuant to this Paragraph 9(a) shall not terminate any phase or partial phase of service for which the Service Commencement Date has occurred. In the event of such termination, Customer shall have no financial or other obligation to Pipeline.

b) If the conditions precedent set forth in Paragraph 7(b) of this Precedent Agreement have not been fully satisfied or waived by Customer by the applicable dates specified therein or if Pipeline has not completed construction of the applicable phase of the Project facilities required to render firm transportation service for Customer and the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date, Phase 3 Service Commencement Date, or Phase 4 Service Commencement Date has not occurred by

[redacted]

respectively, and this Precedent Agreement has not been terminated pursuant to Paragraphs 9(a), 10 or 11 hereof, then Customer may thereafter terminate this Precedent Agreement (and the Service Agreement, if executed), with respect to all phases of service for which the Service Commencement Date has not occurred, by providing thirty (30) days' prior written notice of its intention to terminate to Pipeline; provided, however, if the conditions precedent are satisfied, or waived by Customer within such thirty (30) day notice period (as applicable), then termination of such agreements will not be effective; and, provided further, if Pipeline provides notice of partial Phase 2 service, partial Phase 3 service, or partial Phase 4 service pursuant to Paragraph 4(b), 4(c) or 4(d), respectively, then such termination will not be effective as to such partial phase. Customer's termination right pursuant to this Paragraph 9(b) expires if it is not exercised within ten (10) days after the deadline giving rise to such termination right. A termination pursuant to this Paragraph 9(b) shall not terminate any phase or partial phase of service for which the Service Commencement Date has occurred. In the event of such termination, Customer shall have no financial or other obligation to Pipeline.

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10. Additional Termination Rights. In addition to the provisions of Paragraph 9 hereof, Pipeline may terminate this Precedent Agreement (and the Service Agreement, if executed) by providing written notice of termination to Customer if, by the date specified in Paragraph 7(a)(i), Pipeline, in its sole and reasonable discretion, determines for any reasons that the Project contemplated herein is no longer economically viable. In the event of such termination, Customer shall have no financial or other obligation to Pipeline.

11. Termination upon Service Commencement Date. If this Precedent Agreement is not terminated pursuant to Paragraphs 9 or 10 hereof, then this Precedent Agreement will terminate with respect to each phase on the Service Commencement Date for such phase, and thereafter Pipeline's and Customer's rights and obligations related to the transportation service contemplated herein shall be determined pursuant to the terms and conditions of the Service Agreement, the Negotiated Rate Agreement and Pipeline's FERC Gas Tariff, as effective from time to time. Notwithstanding any termination of this Precedent Agreement pursuant to Paragraphs 9, 10 or 11 hereof, or otherwise, to the extent that a provision of this Precedent Agreement contemplates that one or both Parties may have further rights and/or obligations hereunder following such termination, the provision shall survive such termination as necessary to give full effect to such rights and/or obligations.

12. Creditworthiness. On or within five (5) business days after the Effective Date of this Precedent Agreement, Customer shall satisfy the creditworthiness requirements as set forth in this Paragraph 12.

    a. Creditworthiness Standard. Customer shall at all times during the effectiveness of this Precedent Agreement and the Primary Term of the Service Agreement be "Creditworthy". For purposes herein, Customer will be considered Creditworthy if Customer: (i) has and continues to maintain a long-term senior, unsecured debt rating, or in the absence of a long-term senior, unsecured debt rating, a local long-term issuer rating or an issuer rating, as applicable, from (a) Moody's Investors Service, Inc. or its successor entity of similar business intent ("Moody's") of Baa3 with stable outlook or higher, and (b) Standard & Poor's or its successor entity of similar business intent ("S&P") of BBB- with stable outlook or higher, or if a customer is not rated by one of the foregoing agencies, then a long-term senior, unsecured debt rating, a local long-term issuer rating or an issuer rating, as applicable, from Fitch Ratings Inc. or its successor entity of similar business intent ("Fitch") of BBB- with stable outlook or higher may be substituted, and (ii) has, as of the Effective Date of this Precedent Agreement or, in the event of an assignment or permanent release of this Precedent Agreement, as of the effective date of such assignment or permanent release, sufficient open line of credit with Pipeline and its affiliates. For the avoidance of doubt, the Parties acknowledge that Pipeline has determined that Customer has a sufficient open line of credit with Pipeline and its affiliates and that such determination as it relates to the Project will be effective through the end of the Primary Term of the Service Agreement. [redacted] The extent Pipeline enters into a precedent agreement with any other Project customer which contains a less stringent "Creditworthy" standard than set forth in this subpart (a), Pipeline will offer Customer the option, at Customer's election, to substitute such other standard for the standard set forth in this subpart (a). If at any time and from time to time during the effectiveness of this Precedent Agreement and/or the Service Agreement, Pipeline determines that Customer is not Creditworthy, or if Pipeline initially finds Customer to be Creditworthy but subsequently determines that Customer is no longer Creditworthy, then Customer will provide, or cause to be provided, either a guaranty ("Guaranty") or a letter of credit ("Letter of Credit") in accordance with Paragraphs 12(b) and/or 12(c) as applicable.

b. Guaranty. If Customer fails to meet the requirements of Paragraph 12(a) and Customer elects to provide a Guaranty to satisfy its obligations, such Guaranty shall be issued by Customer's parent company or affiliate, or by a third party (a "Guarantor"), provided such Guarantor is Creditworthy and Guarantor remains Creditworthy for so long as it guarantees Customer's payment obligations. The Guaranty shall: (i) guarantee all payment obligations of Customer under this Precedent Agreement and the Service Agreement, (ii) remain in effect until Customer regains the Creditworthy status, and (iii) be in a form acceptable to Pipeline, which for purposes herein shall mean in form and content substantially similar to Attachment E. If the original Guarantor is, at any time, no longer Creditworthy, Pipeline may require Customer to provide, or cause to be provided, one of the following: (i) a replacement guaranty from a Creditworthy guarantor, or (ii) a letter of credit as described in Paragraph 12(c) to supplement the existing Guaranty, or (iii) a letter of credit as described in Paragraph 12(c) which replaces the existing Guaranty.

c. Letter of Credit. If at any time and from time to time during the effectiveness of this Precedent Agreement and/or the Service Agreement, Customer fails to meet the requirements of Paragraph 12(a) and Customer elects to provide a Letter of Credit to satisfy its obligations, or if Customer has provided a Guaranty but Guarantor at any time fails to meet the requirements of Paragraph 12(b) above, Customer shall provide, or cause to be provided, at its sole cost, a standby irrevocable Letter of Credit from a Qualified Financial Institution. For purposes herein, a "Qualified Financial Institution" shall mean a major U.S. commercial bank, or the U.S. branch offices of a foreign bank, which is not Customer or Customer's Guarantor (or a subsidiary or affiliate of Customer or Customer's Guarantor) and which has assets of at least $10 billion dollars and a credit rating of at least "A-" by S&P and at least "A3" by Moody's. The Letter of Credit shall: (i) remain in effect until the earlier of (A) the end of the Primary Term of the Service Agreement, or (B) until Customer is Creditworthy, (ii) be in a form acceptable to Pipeline, which for purposes herein shall mean in form and content substantially similar to Attachment D hereto, and (iii) be in an amount set forth in the next sentence of this Paragraph 12(c) [redacted] If Customer (or Customer's Guarantor, if applicable) is no longer Creditworthy due solely to the lack of a stable outlook for any of the applicable ratings stated in Paragraph 12(a)(i), then the Letter of Credit will be in an amount equal to [redacted] If Customer (or Customer's Guarantor, if applicable) has a long-term senior, unsecured debt rating, or in the absence of a long-term senior, unsecured debt rating, a local long-term issuer rating or an issuer rating, as applicable, from (a) Moody's of Ba1 or lower, and (b) S&P of BB+ or lower, or if Customer is not rated by one of the foregoing agencies and Customer has substituted a Fitch rating in its place, then a Fitch rating of BB+ or lower, then the Letter of Credit will be in an amount equal to [redacted] To the extent the Letter of Credit is no longer required pursuant to the terms of the Precedent Agreement, Pipeline will return Customer's credit assurance no later than the fifth (5th) business day following Customer's written request. Pipeline may require Customer at its cost to substitute a Letter of Credit with another Qualified Financial Institution if the Letter of Credit provided is, at any time, from a financial institution which is no longer a Qualified Financial Institution.

d. Tariff Credit Provisions Apply. The collateral requirements set forth in this Paragraph 12, while in effect, shall be in lieu of the collateral requirements under Section 3.2(d)(i) of the GT&C of Pipeline's FERC Gas Tariff, which would otherwise be applicable to Customer with respect to service on and after the Service Commencement Date under the Service Agreement; provided that all other credit requirements under the GT&C of Pipeline's FERC Gas Tariff will be applicable to Customer with respect to service on and after the Service Commencement Date under the Service Agreement.

e. Continuing Obligation. The credit support provided to Pipeline in this Paragraph 12 shall continue in effect until full and irrevocable payment of all outstanding balances and charges incurred under the Precedent Agreement and/or during the Primary Term of the Service Agreement.

f. Pipeline Notification. Notwithstanding anything in this Paragraph 12 to the contrary, if at any time and from time to time during the effectiveness of this Precedent Agreement and/or the Service Agreement Pipeline determines that Customer is not satisfying the requirements in this Paragraph 12, Pipeline shall notify Customer in writing, and Customer shall satisfy, or cause to be satisfied, such requirement(s) as soon as reasonably practicable, but in no event later than the close of the fifth (5th) business day following receipt of such notice from Pipeline. If Customer elects to provide a Letter of Credit pursuant to subparagraph 12(c), Pipeline will accept from Customer a cash deposit on or before such fifth (5th) business day until such time as Customer causes such Letter of Credit to be issued, provided that such Letter of Credit shall be issued no later than the close of the fifteenth (15th) business day.

g. Failure to Comply. The failure of Customer to timely satisfy or maintain the requirements set forth in this Paragraph 12 shall in no way relieve Customer or Pipeline of their respective obligations under this Precedent Agreement and/or the Service Agreement, nor shall it affect Pipeline's right to seek damages or performance under this Precedent Agreement and/or the Service Agreement related to Customer's failure to timely satisfy or maintain such requirements. Further, in the event of such failure, Pipeline shall have the right, but not the obligation, to suspend or terminate performance under this Precedent Agreement, or to terminate this Precedent Agreement, upon ten (10) days prior written notice by Pipeline following the fifth (5th) business day notice period set forth in Paragraph 12(f).

h. Term of Credit Provisions and Survival. This Paragraph 12 shall survive the termination of this Precedent Agreement and shall remain in effect until all payment obligations under this Precedent Agreement, and all payment obligations through the end of the Primary Term of the Service Agreement, have been satisfied in full. If the Service Agreement remains in effect after the end of the Primary Term, then Customer shall be responsible for complying with the applicable credit provisions under Pipeline's FERC Gas Tariff in effect at such time.

i. Replacement Customer Creditworthiness. In the event Customer assigns this Precedent Agreement and/or the Service Agreement in accordance with the applicable assignment provision(s), or in the event Customer permanently releases all or a portion of Customer's capacity under the Service Agreement in accordance with Section 14 of the GT&C of Pipeline's FERC Gas Tariff, the assignee and/or the permanent replacement customer, as applicable, shall be required to satisfy the requirements of this Paragraph 12 until all payment obligations under this Precedent Agreement and the Service Agreement have been satisfied in full.

13. Amendments. This Precedent Agreement may not be modified or amended unless the Parties execute written agreements to that effect.

14. Prior Agreements. This Precedent Agreement and its attachments, when executed, supersede all prior agreements and understandings, whether oral or written, with respect

to the Project.

15. Successors; Assignments. Any company which succeeds by purchase, merger, or consolidation of title to the properties, substantially as an entirety, of Pipeline or Customer, will be entitled to the rights and will be subject to the obligations of its predecessor in title under this Precedent Agreement. Otherwise, neither Customer nor Pipeline may assign any of its rights or obligations under this Precedent Agreement without the prior written consent of the other Party hereto, provided that such consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, Pipeline and Customer shall each have the right, without obtaining the other Party's consent, to pledge or assign its rights under this Precedent Agreement and/or the Service Agreement as collateral security for indebtedness incurred by such Party or its affiliate.

16. No Third-Party Rights. Except as expressly provided for in this Precedent Agreement, nothing herein expressed or implied is intended or shall be construed to confer upon or give to any person not a Party hereto any rights, remedies or obligations under or by reason of this Precedent Agreement.

17. Joint Efforts: No Presumptions. Each and every provision of this Precedent Agreement shall be considered as prepared through the joint efforts of the Parties and shall not be construed against either Party as a result of the preparation or drafting thereof. It is expressly agreed that no consideration shall be given or presumption made on the basis of who drafted this Precedent Agreement or any specific provision hereof.

18. Recitals and Representations. The recitals and representations appearing first above are hereby incorporated in and made a part of this Precedent Agreement.

19. Choice of Law. This Precedent Agreement shall be governed by, construed, interpreted,

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and performed in accordance with the laws of the Commonwealth of Massachusetts, without recourse to any laws governing the conflict of laws.

20. Notices. Except as herein otherwise provided, any notice, request, demand, statement, or bill provided for in this Precedent Agreement, or any notice which either Party desires to give to the other, must be in writing and will be sent by two of the following means: electronic mail, facsimile transmission, hand delivery or courier to the other Party at the addresses set forth below:

Pipeline: Attn: General Manager, Business Development
5400 Westheimer Court
Houston, Texas 77056
Phone: (713) 627-5400
Fax: (713) 627-4727
Email: gncrisp@spectraenergy.com

Customer: Edna Karanian
Director, Gas Supply
107 Selden Street
Berlin, Connecticut 06037
Phone: (860) 665-3750
Fax: (860) 665-6296
Email: edna.karanian@nu.com

or at such other address as either Party designates by written notice. Notices given hereunder by electronic mail or facsimile will be deemed to have been effectively given the day indicated on the confirmation accompanying the electronic submission or facsimile. Notices given hereunder by reputable overnight courier will be deemed to have been effectively given on the next business day after sending.

21. Defined Terms. When used in this Precedent Agreement, and unless otherwise defined herein, capitalized terms shall have the meanings set forth in Pipeline's FERC Gas Tariff on file with the Commission, as amended from time to time.

22. Waivers. The waiver by either Party of a breach or violation of any provision of this Precedent Agreement will not operate as or be construed to be a waiver of any subsequent breach or violation hereof.

23. Counterparts. This Precedent Agreement may be executed in any number of counterparts, each of which will be an original, but such counterparts together will constitute one and the same instrument.

24. Headings. The headings contained in this Precedent Agreement are for reference purposes only and shall not affect the meaning or interpretation of this Precedent Agreement.

25. Representations and Warranties. Each Party represents and warrants to each other that as of the Effective Date or, if such representation and warranty is the subject of a condition precedent in Paragraph 7, as of the date of the satisfaction of such condition precedent:

(i) Such Party is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Precedent Agreement;

(ii) The execution, delivery and performance of this Precedent Agreement by such Party have been and remain duly authorized by all necessary corporate action and do not and will not contravene Party's constitutional documents or any contractual restriction binding on Party or its assets;

(iii) This Precedent Agreement has been duly executed and delivered by such Party. This Precedent Agreement constitutes the legal, valid, binding and enforceable obligation of such Party, except as such enforceability may be limited by bankruptcy, insolvency, reorganization and other similar laws and by general principles of equity;

(iv) No governmental authorization, approval, order, license, permit, franchise or consent, and no registration, declaration or filing with any governmental authority is required on the part of such Party in connection with execution and delivery of this Precedent Agreement, although it is subject to the necessary governmental approvals specified herein for its effectuation.

(v) There is no pending or, to the best of such Party's knowledge, threatened action or

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proceeding affecting such Party before any court, governmental authority or arbitrator that could reasonably be expected to materially and adversely affect the financial condition or operations of such Party or the ability of such Party to permit its obligations hereunder, or that purports to affect the legality, validity or enforceability of this Precedent Agreement or would otherwise hinder or prevent performance hereunder.

26. Confidentiality and Disclosures.

(a) The substance and terms of this Precedent Agreement are confidential. Either Party may disclose the substance and terms of this Precedent Agreement to its or its affiliates' directors, officers, employees, representatives, agents, consultants, attorneys or auditors ("Representatives") who have a need to know the substance and terms of this Precedent Agreement. Pipeline and Customer agree not to disclose or communicate, and will cause their respective Representatives not to disclose or communicate, the substance or terms of this Precedent Agreement to any other person, entity, firm, or corporation without the prior written consent of the other Party, provided that either Party may disclose the substance or terms of this Precedent Agreement as required by law, order, rule or regulation of any duly constituted governmental body or official authority having jurisdiction, subject to the condition that the disclosing Party first give the other Party five (5) business days' notice of same or as much notice as possible under the circumstances, so that a protective order or other protective arrangements may be sought. Notwithstanding the foregoing, the Parties acknowledge that (A) Pipeline may, in its sole discretion, exercised reasonably, (i) file a copy of this Precedent Agreement with the FERC under seal in connection with the FERC certificate application, (ii) place on public file with the FERC a description of the terms of any negotiated rate prior to the commencement of firm transportation service under the Service Agreement, and (iii) use the terms and conditions of this Precedent Agreement (excluding any information proprietary to Customer) in Pipeline's preparation of the pro forma precedent agreement for other shippers under the Project, and (B) Customer, in its sole discretion, may provide Project information, including a copy of this Precedent Agreement, to the New Hampshire Public Utility Commission; provided Pipeline or Customer will request confidential treatment for any such filing or written disclosure. Such filings will not constitute a breach of this confidentiality provision and will not require compliance with the foregoing five (5) day notice provision. If this Precedent Agreement is terminated pursuant to Paragraphs 9, 10 or 11 above or otherwise by mutual agreement of the Parties, then this Paragraph 26 will survive for a period of two (2) years from and after the effective date of such termination.

(b) The following will not constitute confidential information for purposes of this Precedent Agreement: (i) information which is or becomes generally available to the public other than as a result of a disclosure by the Party receiving the confidential information or its Representatives; (ii) information which was already known to the Party receiving the confidential information on a non-confidential basis prior to being furnished such information by the other Party; (iii) information which becomes available to the Party receiving the confidential information on a non-confidential basis from a source other than the Party providing such confidential information or its Representative if such source was not known by the Party receiving such information to be subject to any prohibition against transmitting the information to such Party; or (iv) information which was or is independently developed by Party receiving the confidential information or its Representatives without reference to, or consideration of, confidential information.

(c) Notwithstanding Paragraph 26(a) above, and subject to the Parties' prior approval of any public announcements or disclosures related to Customer's participation in the Project, it is understood and agreed by the Parties that the intent of the marketing effort for the Project will be to disclose to other potential Project customers that Pipeline and Customer have executed this Precedent Agreement for Customer to be an anchor shipper for the Project. Customer agrees that Pipeline shall be permitted to make public announcements and disclosures related to the existence of this Precedent Agreement, and the MDTQ, target Service Commencement Date and Primary Term set forth herein, without Pipeline obtaining any further approvals from Customer. Likewise, Pipeline agrees that Customer shall be permitted to discuss the Project with its state regulators and other stakeholders, including the existence of this Precedent Agreement, and the MDTQ, MSQ, target Service Commencement Date and Primary Term set forth herein, without obtaining any further approvals from Pipeline.

[signature page follows]

EXECUTION COPY

IN WITNESS WHEREOF, the Parties hereto have caused this Precedent Agreement to be duly executed by their duly authorized officers as of the day and year first above written.

Algonquin Gas Transmission, LLC	Public Service Company of New Hampshire d/b/a Eversource Energy
By: William T. Yardley	By: James G. Daly
Title: President	Title: Vice President Energy Supply

EXECUTION COPY

Attachment A-1
Form of Rate Schedule ERS

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RATE SCHEDULE ERS

ENERGY RELIABILITY SERVICE

1. AVAILABILITY

1.1 This rate schedule is available for firm transportation and storage of natural gas by Algonquin Gas Transmission, LLC (hereinafter called "Algonquin") and for any party (hereinafter called "Customer"), when:

(a) Customer has executed a precedent agreement pursuant to the Open Season held from February 18, 2015 to May 1, 2015 or made a valid request for firm service pursuant to Section 2 of the General Terms and Conditions of this FERC Gas Tariff of which this rate schedule is a part;

(b) Sufficient firm capacity is available to effectuate such service without any construction of facilities or other investment by Algonquin, or Algonquin has waived this requirement in writing; and

(c) Customer and Algonquin have executed a service agreement ("Customer's ERS Service Agreement") in the form contained in the FERC Gas Tariff of which this rate schedule is a part.

(d) Under this Rate Schedule ERS, a single ERS Service Agreement is available to multiple parties who meet the qualifications set forth in the Multiple Shipper Option Agreement and such agreement has been executed by the Customers, Algonquin and other relevant parties.

1.2 Transportation service effectuated through capacity on the Brayton Point Lateral, the Manchester Street Lateral, the Canal Lateral, the Cape Cod Lateral, the Northeast Gateway Lateral, the J-2 Facility, or the Kleen Energy Lateral, as such lateral facilities are defined in Rate Schedule AFT-CL is not available under this rate schedule; provided, however, that the following interconnections are available under this Rate Schedule ERS:

(a) between the Brayton Point Lateral and Algonquin's mainline (M&R No. 80075),

(b) between the Manchester Street Lateral and Algonquin's mainline (M&R No. 80071),

(c) between the Canal Lateral and Algonquin's mainline (M&R No. 80047),

(d) between the Northeast Gateway Lateral and the HubLine offshore system in Massachusetts Bay, Massachusetts,

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(e) between the J-2 Facility and Algonquin's mainline (M&R No. 80095), and

(f) between the Middletown Lateral and the Kleen Energy Lateral.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Service provided pursuant to this Rate Schedule ERS will be firm, except as provided herein and in Sections 16 and 24 of the General Terms and Conditions of this FERC Gas Tariff, and constitutes one of the "no-notice" service options, as that term is used in Order No. 636, that is available from Algonquin. Unless otherwise specified in this Rate Schedule ERS or in Customer's ERS Service Agreement, service hereunder shall be available on any Gas Day of the year, subject to Customer's MDTQ, MHTQ, MSQ, MDIQ, and MDWQ limitations, as applicable.

2.2 In order to provide primary firm transportation service to Customer pursuant to this Rate Schedule ERS at any time during a Gas Day, Algonquin shall reserve for scheduling purposes a quantity ("Reserved Capacity") equal to Customer's MDTQ less the total quantity scheduled for the Gas Day pursuant to Section 23.1(a) or Section 23.1(b) of the General Terms and Conditions of this FERC Gas Tariff for Customer on Customer's ERS Service Agreement during any of the nomination cycles described in Section 22 of the General Terms and Conditions of this FERC Gas Tariff. Such Reserved Capacity can be utilized by Customer during subsequent nomination cycles for that Gas Day to request and schedule nominations pursuant to Section 23.1(a) of the General Terms and Conditions of this FERC Gas Tariff. If, at any time during the Gas Day, Customer reduces previously scheduled quantities under Customer's ERS Rate Schedule, the resulting available capacity shall not be included in the calculation of Reserved Capacity.

2.3 Enhanced Maximum Hourly Transportation Quantity.

(a) Upon request by Customer, Algonquin will estimate the facilities and costs required to further enhance the applicable firm MHTQ at any Point of Delivery under Customer's service agreement. Subject to the agreement between Algonquin and Customer on an appropriate rate or cost reimbursement for such MHTQ enhancement ("Enhanced MHTQ"), the receipt of all necessary approvals for construction of such facilities on terms and conditions acceptable to Algonquin and Customer, and the placement of such facilities into service, such Enhanced MHTQ shall be specified in Customer's executed service agreement.

(b) The MHTQ or Enhanced MHTQ applicable to Customer's ERS Service Agreement will not limit Customer's right to hourly flow flexibility that otherwise would be available to all customers.

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2.4 Transportation Component of the Service.

(a) Algonquin shall receive from Customer, or for the account of Customer, at the Primary Point(s) of Receipt specified in Customer's ERS Service Agreement for transportation hereunder daily quantities of gas tendered for the account of Customer up to Customer's Maximum Daily Transportation Quantity ("MDTQ") plus an amount reflecting the Fuel Reimbursement Quantity as defined in Section 32 of the General Terms and Conditions of this FERC Gas Tariff; provided however, Algonquin shall not be obligated to, but may at its option, receive at any Point(s) of Receipt on any Gas Day a quantity of gas in excess of the applicable Maximum Daily Receipt Obligation ("MDRO") plus any applicable Fuel Reimbursement Quantity (collectively referred to as "Point Overrun Quantities"), provided that, if more than one Customer requests receipts in excess of its MDRO at a Point of Receipt, and the sum of all such requests exceeds the available capacity at such Point of Receipt, Algonquin shall apportion such receipts in excess of MDRO among such Customers pro rata according to the Customers' firm MDROs at the relevant Point of Receipt. In no event shall Point Overrun Quantities at a Point(s) of Receipt be available for service requested pursuant to Section 4.3 or Section 4.4 of this Rate Schedule ERS.

(b) Upon receipt of such natural gas for Customer's account, Algonquin shall, after making allowance for the Fuel Reimbursement Quantity, transport and deliver hourly quantities of gas required by Customer up to Customer's MHTQ or Enhanced MHTQ, as applicable, at the Primary Point(s) of Delivery specified in Customer's ERS Service Agreement; provided however, Algonquin shall not be obligated to, but may at its option, deliver at any Point(s) of Delivery an hourly quantity exceeding the MHTQ or Enhanced MHTQ, as applicable, and on any Gas Day a quantity of gas in excess of the applicable Maximum Daily Delivery Obligation ("MDDO") ("Point Overrun Quantities"), provided that, if more than one Customer requests deliveries in excess of its MDDO at a Point of Delivery, and the sum of all such requests exceeds the available capacity at such Point of Delivery, Algonquin shall apportion such deliveries in excess of MDDO among such Customers pro rata according to the Customers' firm MDDOs at the relevant Point of Delivery. In no event shall Point Overrun Quantities at a Point(s) of Delivery be available for service requested pursuant to Section 4.3 or Section 4.4 of this Rate Schedule ERS.

(c) Provided such quantities have been scheduled in accordance with Section 23 of the General Terms and Conditions of this FERC Gas Tariff, Customer may tender

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quantities of gas in excess of the MDTQ plus any applicable Fuel Reimbursement Quantity on any Gas Day if in Algonquin's reasonable judgment transportation of such gas can be accomplished by Algonquin without detriment to any other Customer under any of Algonquin's rate schedules. Such excess quantities shall be deemed to be Authorized Overrun Quantities. In no event shall Authorized Overrun Quantities be available for service requested pursuant to Section 4.3 or Section 4.4 of this Rate Schedule ERS.

2.5 Storage Component of the Service.

(a) Algonquin shall receive for Customer's account quantities of gas, plus any applicable Fuel Reimbursement Quantity, and inject into a regional storage facility designated in Customer's ERS Service Agreement as a Primary Point of Receipt ("Storage Facility") in accordance with Section 7 of this Rate Schedule ERS for Customer's account such quantities of gas. Algonquin shall withdraw from the Storage Facility for Customer, at Customer's request, in accordance with Section 8 of this Rate Schedule ERS, quantities of gas from Customer's Storage Inventory, plus any applicable Fuel Reimbursement Quantity, and deliver for Customer's account such quantities. Such service shall be firm except as provided herein and in Pipeline's General Terms and Conditions of this FERC Gas Tariff of which this rate schedule is a part and shall be available to Customer each Gas Day of the year on a firm basis during the injection and withdrawal seasons described below:

(1) Injection Seasons

(i) Winter: September 1 through November 30

(ii) Summer: April 1 through July 20

(2) Withdrawal Seasons

(i) Winter: December 1 through March 31

(ii) Summer: July 21 through August 31

(b) Provided the receipt of gas and the injection of such gas into the Storage Facility for Customer's account can be accomplished by Algonquin without detriment to Algonquin's facilities and/or Algonquin's ability to meet its firm obligations to other Customers, Algonquin upon request of Customer shall inject, on any Gas Day of the year, on an interruptible basis quantities of gas in excess of Customer's Maximum Daily Injection Quantity, but not to exceed Customer's

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MSQ. Such excess quantities shall be deemed to be Excess Injection Gas. Excess Injection Gas will not be available for service requested pursuant to Sections 4.3 and 4.4 of this Rate Schedule ERS.

(c) Provided the withdrawal of gas from the Storage Facility for Customer can be accomplished by Algonquin without detriment to Algonquin's facilities and/or Algonquin's ability to meet its firm obligations to other Customers, Algonquin upon request of Customer shall schedule and withdraw, on any Gas Day of the year, on an interruptible basis gas in excess of Customer's Maximum Daily Withdrawal Quantity, provided such excess withdrawal does not result in a quantity of gas that is less than zero in Customer's Storage Inventory. Such excess quantities shall be deemed to be Excess Withdrawal Gas. Excess Withdrawal Gas will not be available for service requested pursuant to Sections 4.3 and 4.4 of this Rate Schedule ERS.

(d) In addition to injections into the Storage Facility for quantities of gas transported under this Rate Schedule ERS, Algonquin will inject quantities of gas transported under other AGT service agreements, according to the terms and conditions of such agreements, at the interconnection of the Storage Facility in accordance with the storage injection terms and conditions as set forth in Section 2.5(a) and Section 2.5(b) of this Rate Schedule ERS.

(e) In addition to withdrawals from the Storage Facility for quantities of gas transported under this Rate Schedule ERS, Algonquin will withdraw quantities of gas transported under other AGT service agreements, according to the terms and conditions of such agreements, at the interconnection of the Storage Facility in accordance with the storage withdrawal terms and conditions as set forth in Section 2.5(a) and Section 2.5(c) of this Rate Schedule ERS.

2.6 Algonquin shall not be obligated to add any facilities or expand the capacity of Algonquin's pipeline system in any manner in order to provide service to Customer pursuant to this rate schedule; provided, however, Algonquin may, at its option, and with Customer's consent, add facilities or expand capacity to provide such service, subject to Section 42 of the General Terms and Conditions of this FERC Gas Tariff.

2.7 Capacity Release.

(a) Capacity will be released pursuant to Section 14 of the General Terms and Conditions of this FERC Gas Tariff.

(b) Service provided under this Rate Schedule ERS is a combination of transportation and storage service. Customers executing a Service Agreement

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under this Rate Schedule ERS may elect to release a portion or all of their combined firm transportation and storage service under this Rate Schedule ERS. An ERS Customer may release transportation service only, storage service only, or a combination of the two services under this Rate Schedule ERS pursuant to Section 2.7 of this Rate Schedule ERS. Service provided under this Rate Schedule ERS is most effective when the transportation component and storage component of the service remain combined under Rate Schedule ERS and the service is executed as intended under this rate schedule.

(c) Customer shall remain ultimately liable to Algonquin for all Reservation Charges and Reservation Surcharges under the terms of its service agreement with Algonquin, pursuant to Section 14 of the General Terms and Conditions.

3. RATES

3.1 Unit Rates. The applicable maximum and minimum unit rates for the service provided by Algonquin pursuant to this rate schedule are set forth in the currently effective Statement of Rates for Rate Schedule ERS of this tariff and are hereby incorporated herein. Such rates are subject to adjustment pursuant to Section 33 and Section 34 of the General Terms and Conditions of this tariff. The applicable unit rates to be charged on any Gas Day by Algonquin for gas delivered to Customer shall not be in excess of the maximum unit rate or less than the minimum unit rate.

3.2 Commencing for the Month in which Customer's ERS Service Agreement is effective and for each Month thereafter unless otherwise specified in the applicable service agreement, the monthly bill for service under this Rate Schedule ERS shall be the sum of the amounts set forth in Sections 3.2 below.

(1) Reservation Charge: The charge per Month per Dth of Customer's highest MDTQ during the Contract Year, as specified in Customer's executed ERS Service Agreement; plus

(2) Commodity Charge: The applicable commodity rate multiplied by the quantity of gas delivered in the Month under this rate schedule (excluding Authorized Overrun Quantities) at the Point(s) of Delivery; plus

(3) Authorized Overrun Charge: The applicable authorized overrun charge per Dth of Authorized Overrun Quantity delivered to Customer for the Month under Section 2.4(c) of this rate schedule; plus

(4) Imbalance Resolution Charges: The applicable imbalance resolution charges assessed pursuant to Section 25 of the General Terms and Conditions, including boil off; plus

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(5) Scheduling Penalties: The applicable scheduling penalties assessed pursuant to Section 23 of the General Terms and Conditions; plus

(6) Injection Charge: The Injection Charge Rate multiplied by the quantity of gas injected, excluding Excess Injection Gas, for Customer's account during the Month pursuant to Customer's ERS Service Agreement; plus

(7) Withdrawal Charge: The Withdrawal Charge Rate multiplied by the quantity of gas withdrawn, excluding Excess Withdrawal Gas, for Customer's account during the Month pursuant to Customer's ERS Service Agreement; plus

(8) Excess Injection Charge: The Excess Injection Charge Rate multiplied by the quantities of Excess Injection Gas received for Customer's account during the Month pursuant to Customer's ERS Service Agreement; plus

(9) Excess Withdrawal Charge: The Excess Withdrawal Charge Rate multiplied by the quantities of Excess Withdrawal Gas delivered for Customer's account during the Month pursuant to Customer's ERS Service Agreement; plus

(10) Unauthorized Contract Overrun Penalties: The applicable unauthorized contract overrun penalties assessed pursuant to Section 31 of the General Terms and Conditions; less

(11) Revenue Credit: The revenue credit provided for in Section 41 of the General Terms and Conditions.

4. NOMINATIONS AND SCHEDULING OF RECEIPTS AND DELIVERIES

4.1 Nominations and Scheduling.

(a) If Customer desires service on any Gas Day under this rate schedule, Customer shall provide a nomination to Algonquin in accordance with Section 22 of the General Terms and Conditions of this FERC Gas Tariff. In addition, at any time during a Gas Day, Customer may submit a nomination in accordance with Section 4.3 or Section 4.4 of this Rate Schedule ERS to request the delivery of a quantity of gas during that Gas Day, up to the Maximum Daily Transportation Quantity ("MDTQ"), at those points specified in Exhibit B to Customer's ERS Service Agreement as Primary Point(s) of Delivery.

(b) Based upon the nomination of Customer, Algonquin shall schedule receipts and deliveries of gas in accordance with Section 23 of the General Terms and

Conditions of this FERC Gas Tariff and Section 4.3 or Section 4.4, as applicable, of this Rate Schedule ERS. It is the responsibility of Customer to adjust its deliveries and receipts to conform to the scheduled quantities.

4.2 Delivery of Gas. Based upon the daily quantity scheduled, Algonquin shall deliver Customer's scheduled quantity taking into account the Fuel Reimbursement Quantity. It is the intention of Algonquin that daily deliveries of gas at the Point(s) of Delivery by Algonquin hereunder shall be as nearly equal as possible to daily receipts of gas at the Point(s) of Receipt by Algonquin for transportation hereunder, less the applicable Fuel Reimbursement Quantity. Any excess or deficiency in such receipts, less the applicable Fuel Reimbursement Quantity, and deliveries shall be resolved in accordance with Section 25 of the General Terms and Conditions of this FERC Gas Tariff. Nothing in this rate schedule shall limit Algonquin's right to take actions pursuant to Section 26 of the General Terms and Conditions of this FERC Gas Tariff.

4.3 Reserved No-Notice Service. Notwithstanding the quantities nominated by Customer and scheduled by Algonquin pursuant to Sections 4.1 and 4.2 of this Rate Schedule ERS, Customer shall be entitled on any Gas Day to increase its nominated receipts up to the available MDRO (as may be further limited by aggregate MDRO) at any Primary Point(s) of Receipt and nominated deliveries up to the available MDDO (as may be further limited by aggregate MDDO) at any Primary Point(s) of Delivery, up to the MHTQ or Enhanced MHTQ, as applicable, during any Hour, and up to the available MDTQ, subject to the provisions of this Section 4.3; provided, however, that the maximum quantity that can be requested pursuant to this Section 4.3 cannot exceed the Reserved Capacity calculated pursuant to Section 2.2 of this Rate Schedule ERS and any nominated increase is a primary firm nomination.

(a) In the event Customer requires an increase or decrease in its primary firm scheduled deliveries at a Primary Point(s) of Delivery, and (1) Customer provides notice to Algonquin of such requirement pursuant to Section 22 of the General Terms and Conditions of this FERC Gas Tariff prior to the requested effective time for the increased or decreased deliveries, and (2) the corresponding increase or decrease in Customer's scheduled receipts at a Primary Point(s) of Receipt is confirmed by Algonquin, Algonquin shall perform service at the level of scheduled increased or decreased deliveries for the remainder of the applicable Gas Day; provided, however, that, absent a concurrent nominated and confirmed receipt, Algonquin shall not deliver the quantity requested pursuant to this Section 4.3 to, or for the account of, Customer.

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(b) If Customer is out of balance at the end of any Month as a result of the invocation of the provisions of this Section 4.3, the remaining imbalance shall be reconciled in accordance with Section 25 of the General Terms and Conditions of this FERC Gas Tariff.

4.4 <u>No-Notice Supply Service.</u>

(a) Customer shall be entitled to request the delivery of gas on a primary firm basis from Algonquin pursuant to this Rate Schedule ERS at a Primary Point(s) of Delivery without a concurrent nominated and confirmed Point(s) of Receipt; provided, however, that the maximum quantity that can be requested pursuant to this Section 4.4 cannot exceed the lesser of Customer's MDWQ minus any previously withdrawn storage quantities for the Gas Day, Customer's Reserved Capacity calculated pursuant to Section 2.2 of this Rate Schedule ERS, Customer's Storage Inventory, Customer's available MDRO at the Storage Facility, Customer's available MDDO (and aggregate MDDO) at the Primary Point(s) of Delivery, or the amount of Customer's unutilized primary firm transportation path from the Storage Facility to the requested Primary Point(s) of Delivery. Algonquin will perform service at the requested level of delivery for a period of up to two (2) Hours, but not extending past the end of the applicable Gas Day, beginning upon Algonquin's receipt of such notice. In no event shall Customer be entitled to request the delivery of a quantity of gas on any Gas Day in excess of the portion of the MDTQ or MDDO (and aggregate MDDO) specified in Customer's ERS Service Agreement that remains available at the time of such request.

(b) Within two (2) Hours of the commencement of deliveries to Customer, Customer must submit an acceptable nomination that is subsequently scheduled by Algonquin and must begin tendering to Algonquin from a Point(s) of Receipt a quantity of gas, plus any applicable Fuel Reimbursement Quantity, sufficient to ensure that the nominated transaction is balanced at the end of the Gas Day. In the event that Customer does not submit such nomination and begin tendering gas to Algonquin within such two (2) Hour period, Algonquin shall discontinue the delivery of gas that was initiated pursuant to Section 4.4(a) above and shall submit a nomination under Customer's ERS Service Agreement and begin tendering to Algonquin from Customer's Storage Inventory a sufficient quantity to ensure that the nominated transaction is balanced at the end of the Gas Day. The Imbalance Resolution Procedures described in Section 25 of the General Terms and Conditions of this FERC Gas Tariff shall not apply to Section 4.4 of this Rate Schedule ERS.

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4.5 Commingling of Gas. From the time the natural gas is received by Algonquin at the Point(s) of Receipt, Algonquin shall have the unqualified right to commingle such natural gas with other gas in Algonquin's system.

5. OTHER OPERATING CONDITIONS

Algonquin's obligation to provide service under this rate schedule is subject to the following conditions being satisfied:

5.1 Customer shall make all necessary arrangements with other parties at or upstream of the Point(s) of Receipt where Customer tenders gas to Algonquin, and at or downstream of the Point(s) of Delivery where Algonquin delivers gas for Customer's account, and such arrangements must be compatible with Algonquin's system operations.

5.2 Algonquin shall schedule receipts at a Secondary Point of Receipt or deliveries at a Secondary Point of Delivery pursuant to the provisions of Sections 48.2 and 48.3 of the General Terms and Conditions. Algonquin shall not be required to schedule any receipt at a Secondary Point of Receipt, nor shall Algonquin be required to schedule any delivery at a Secondary Point of Delivery if such receipt or delivery would impair deliveries to any firm service Customer at a Primary Point of Delivery or receipts at a Primary Point of Receipt.

5.3 To the extent that any upstream entity involved in handling Customer's gas refuses or is unable to deliver gas to Algonquin, Algonquin shall not be required to continue deliveries of gas on behalf of Customer. Prior to any reduction or interruption in service due to the failure of such upstream entity to deliver gas on behalf of Customer, Algonquin shall provide notice in a time and manner that is reasonable under then existing conditions. To the extent that any downstream entity involved in handling Customer's gas refuses or is unable to receive gas from Algonquin, Algonquin shall have the right to reduce deliveries of gas on behalf of Customer.

5.4 Absent mutual agreement of Algonquin and the upstream pipeline operator, the daily quantities of natural gas transported shall be delivered at the Point(s) of Receipt at an hourly rate of 1/24th of the scheduled daily quantity, unless such quantities are delivered to Algonquin for service pursuant to Section 4.3 or Section 4.4 of this Rate Schedule ERS. The daily quantities of natural gas transported shall be accepted at the Point(s) of Delivery at the applicable MHTQ or Enhanced MHTQ rate as set forth in Exhibit B of Customer's ERS Service Agreement. Algonquin may deliver gas at the Point(s) of Delivery at a rate other than the MHTQ or Enhanced MHTQ specified within Exhibit B of Customer's ERS Service Agreement if, in Algonquin's reasonable judgment,

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transportation of such gas can be accomplished by Algonquin without detriment to any other Customer under any of Algonquin's firm rate schedules.

6. POINT(S) OF RECEIPT AND DELIVERY

6.1 Primary Points of Receipt:

(a) The Primary Point(s) of Receipt at which Algonquin shall receive gas under this rate schedule shall be specified in an exhibit to Customer's ERS Service Agreement. Such exhibit shall specify for each Primary Point of Receipt the MDRO and receipt pressure obligations. Such exhibit by mutual written agreement may be superseded by a new exhibit which may add or delete specific points or make other changes thereto that the parties deem appropriate. Algonquin shall not accept any proposed Primary Point(s) of Receipt, or quantity at any Primary Point(s) of Receipt, or change in quantities among Primary Point(s) of Receipt if (i) the resulting aggregate MDROs at all of Customer's Primary Point(s) of Receipt would exceed Customer's MDTQ, except under such circumstances as specified in Section 37.1(a) of the General Terms and Conditions of this FERC Gas Tariff, or (ii) in doing so, in Algonquin's reasonable judgment, Algonquin would impair its ability to satisfy its existing firm obligations to receive gas pursuant to other firm service agreements under which such Point(s) of Receipt are Primary Points of Receipt and to purchase and receive its Company Use Gas at maximum deliverability levels, as such Company Use Gas arrangements exist under agreements effective at the date of Customer's request or reasonably expected by Algonquin to be effective within six months of the request. If Customer desires to utilize the no-notice option described in Section 4.4 above, the exhibit to Customer's ERS Service Agreement or the applicable Addendum to Replacement Customer's Capacity Release Umbrella Agreement, as applicable, must identify the Storage Facility as a Primary Point of Receipt with an MDRO that is greater than zero.

(b) A Replacement Customer that acquired capacity or a Releasing Customer that released capacity pursuant to Section 2.7 of this Rate Schedule ERS may request, subject to the availability of point and path capacity, any interconnection between the facilities of Algonquin and the facilities of other operators (with the exception of those facilities specifically identified in Section 1.2 of this rate schedule as not available for service under this rate schedule) for use as a Primary Point of Receipt in a segmented transaction; provided, however, that Algonquin shall not accept any proposed Primary Point of Receipt to the extent that (a) the resulting aggregate contractual entitlements under the

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related releasing and replacement contracts along any segment would exceed the MDTQ of the original contract, or (b) the quantities transported along any segment under the resulting aggregate related releasing and replacement contracts would exceed the MDTQ of the original contract. In the event that Replacement Customer selects a new Primary Point of Receipt that is located within the acquired contract path, the portion of the path no longer covered by that contract is deemed to be unsubscribed capacity that may be sold by Algonquin for the term of the capacity release agreement. Upon termination of the capacity release agreement, all capacity covered by the original release, including the original Primary Points of Receipt, shall revert to the Releasing Customer, and any Primary Points of Receipt granted during the term of the capacity release agreement shall revert to Algonquin as unsubscribed capacity.

6.2 Secondary Points of Receipt: Notwithstanding the foregoing, all interconnections between the facilities of Algonquin and the facilities of other operators shall be available for use by Customer as Secondary Points of Receipt, with the exception of interconnections with those facilities specifically identified in Section 1.2 of this rate schedule as not available for service under this rate schedule; provided, however, that the following interconnections are available for use as Secondary Points of Receipt under this Rate Schedule ERS, subject to and pursuant to Section 48.2 of the General Terms and Conditions of this FERC Gas Tariff:

(a) between the Brayton Point Lateral and Algonquin's mainline,

(b) between the Manchester Street Lateral and Algonquin's mainline,

(c) between the Canal Lateral and Algonquin's mainline,

(d) between the Northeast Gateway Lateral and the HubLine offshore system in Massachusetts Bay, Massachusetts,

(e) between the J-2 Facility and Algonquin's mainline, and

(f) between the Middletown Lateral and the Kleen Energy Lateral.

6.3 Primary Points of Delivery:

(a) The Primary Point(s) of Delivery at which Algonquin shall deliver gas for Customer's account under this rate schedule shall be specified in an exhibit to the service agreement executed by Algonquin and Customer. Such exhibit by mutual agreement may be superseded by a new exhibit which may add or delete specific points or make other changes thereto that the parties deem

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appropriate. Such exhibit shall specify for each Point of Delivery the MDDO and delivery pressure obligations. Algonquin shall not accept any proposed Primary Point(s) of Delivery, or quantity at any Primary Point(s) of Delivery, or change in quantities among Primary Point(s) of Delivery if (a) the resulting aggregate MDDOs at all of Customer's Primary Point(s) of Delivery would exceed Customer's MDTQ, except (i) under such circumstances as specified in Section 37.1(a) of the General Terms and Conditions of this FERC Gas Tariff, or (ii) under such circumstances in which Customer's proposed Primary Point(s) of Delivery and proposed change in quantities among Primary Point(s) of Delivery are in connection with the construction or modification of facilities that are directly connected to Algonquin, and the costs of such facilities are paid for or reimbursed by Customer or by third parties who connect to and have such Point(s) of Delivery added to Customer's service agreement, or (b) in doing so, in Algonquin's reasonable judgment, Algonquin would impair its ability to satisfy its existing firm obligations to deliver gas pursuant to other firm service agreements under which such Point(s) of Delivery are Primary Point(s) of Delivery. If Customer desires to utilize either of the no-notice options described in Sections 4.3 and 4.4 above, the exhibit to Customer's ERS Service Agreement or the applicable Addendum to Replacement Customer's Capacity Release Umbrella Agreement, as applicable, must identify a Primary Point of Delivery with an MDDO that is greater than zero.

(b) A Replacement Customer that acquired capacity or a Releasing Customer that released capacity pursuant to Section 2.7 of this Rate Schedule ERS may request, subject to the availability of point and path capacity, any interconnection between the facilities of Algonquin and the facilities of other operators (with the exception of those facilities specifically identified in Section 1.2 of this rate schedule as not available for service under this rate schedule) for use as a Primary Point of Delivery in a segmented transaction provided, however, that Algonquin shall not accept any proposed Primary Point of Delivery to the extent that (a) the resulting aggregate contractual entitlements under the related releasing and replacement contracts along any segment would exceed the MDTQ of the original contract, or (b) the quantities transported along any segment under the resulting aggregate related releasing and replacement contracts would exceed the MDTQ of the original contract. In the event that Replacement Customer selects a new Primary Point of Delivery that is located within the acquired contract path, the portion of the path no longer covered by that contract is deemed to be unsubscribed capacity that may be sold by Algonquin for the term of the capacity release agreement. Upon

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termination of the capacity release agreement, all capacity covered by the original release, including the original Primary Points of Delivery, shall revert to the Releasing Customer, and any Primary Points of Delivery granted during the term of the capacity release agreement shall revert to Algonquin as unsubscribed capacity.

6.4 Secondary Points of Delivery: Notwithstanding the foregoing, all interconnections between the facilities of Algonquin and the facilities of other operators shall be available for use by Customer as Secondary Points of Delivery, with the exception of interconnections with those facilities specifically identified in Section 1.2 of this rate schedule as not available for service under this rate schedule; provided, however, that the following interconnections are available for use as Secondary Points of Delivery under this Rate Schedule ERS, subject to and pursuant to Section 48.2 of the General Terms and Conditions of this FERC Gas Tariff:

(a) between the Brayton Point Lateral and Algonquin's mainline,

(b) between the Manchester Street Lateral and Algonquin's mainline,

(c) between the Canal Lateral and Algonquin's mainline,

(d) between the Northeast Gateway Lateral and the HubLine offshore system in Massachusetts Bay, Massachusetts,

(e) between the J-2 Facility and Algonquin's mainline, and

(f) between the Middletown Lateral and the Kleen Energy Lateral.

7. INJECTION PROVISIONS

7.1 General Procedure. If Customer desires Algonquin to store gas in the Storage Facility for Customer's account under this Rate Schedule, Customer shall give notice to Algonquin in accordance with Section 22 of the General Terms and Conditions of this FERC Gas Tariff. Such notice shall specify the quantity of gas, plus any Fuel Reimbursement Quantity, which Customer desires to be injected into the Storage Facility under this Rate Schedule. Algonquin shall thereupon inject the quantity of gas so nominated subject to the limitations set forth herein. The maximum quantity of gas which Algonquin is obligated on any Gas Day to inject into the Storage Facility under this Rate Schedule shall be the Maximum Daily Injection Quantity specified in Customer's ERS Service Agreement. In addition, Algonquin shall be obligated to accept gas for Customer's account in accordance with this Section 7.1 only when Customer's Storage Inventory is less than the Maximum Storage Quantity specified in Customer's ERS Service Agreement.

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7.2 Algonquin shall permit transfers of title of gas in Storage Inventory between Customers, provided both Customers have executed a service agreement under Rate Schedule ERS and that such transfer does not permit either Customer to exceed its Maximum Storage Quantity specified in such service agreement. A Customer that desires to transfer Storage Inventory to another Customer must submit the required information, which shall include, at a minimum, the identification of the service agreements involved in the transfer, the quantity to be transferred, and the effective date of the transfer, via the LINK® System. If a proposed transfer involves a service agreement that has terminated, the required information must be submitted within three (3) Business Days after the end of the term of the applicable agreement. The proposed transfer must be confirmed via the LINK® System by the Customer to whom the Storage Inventory is to be transferred before the transfer is processed by Algonquin.

8. <u>WITHDRAWAL PROVISIONS</u>

If Customer desires the delivery of gas stored for Customer's account under this Rate Schedule ERS, Customer shall give notice to Algonquin in accordance with Section 22 of the General Terms and Conditions of this FERC Gas Tariff. Such notice shall specify the quantity of gas, plus any Fuel Reimbursement Quantity, which Customer desires to be withdrawn from the Storage Facility and delivered under this Rate Schedule ERS. Algonquin shall thereupon deliver to Customer the quantity of gas so nominated; provided, however, the maximum quantity of gas which Algonquin is obligated on any Gas Day to withdraw from the Storage Facility under this Rate Schedule shall be the Maximum Daily Withdrawal Quantity specified in Customer's ERS Service Agreement. In addition, Algonquin shall be obligated to withdraw gas for Customer in accordance with this Section 8 only when Customer's Storage Inventory is greater than zero.

9. <u>GENERAL TERMS AND CONDITIONS</u>

The applicable General Terms and Conditions of this FERC Gas Tariff are hereby made a part of this rate schedule.

Attachment A-2
Form of Rate Schedule ERS Service Agreement

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

[This Form of Service Agreement may be revised to reflect non-substantive changes that are included in the Form of Service Agreement applicable to Rate Schedule ERS as of the date of execution pursuant to Paragraph 3 of the Precedent Agreement and will be revised to reflect the specific terms of the Precedent Agreement, including, without limitation, the contractual ROFR.]

Date: ___________________________, Contract No. ___________________

SERVICE AGREEMENT

This AGREEMENT is entered into by and between Algonquin Gas Transmission, LLC, ("Algonquin") and _______________________________________ ("Customer").

[or, when applicable, "This Agreement entered into this __ day of _______, ____, by and between Algonquin Gas Transmission, LLC ("Algonquin") and ________________, as "Administrator" on behalf of the Principals set forth in Multiple Shipper Option Agreement ("MSOA") Contract No. ______, hereinafter individually and collectively referred to as "Customer," which Principals meet the requirements set forth in such MSOA which is incorporated herein by reference."]

WHEREAS, [this and an additional clause(s) may be included to describe the historical or factual context of the Agreement, to describe or identify a precedent agreement, and any other agreements if applicable, between Algonquin and Customer related to the Agreement, and/or to describe or define the facilities necessary to provide service under the Agreement, and will not include binding consideration.]

[***In the event that the capacity was awarded as Interim Capacity pursuant to Section 2.6 of the General Terms and Conditions of the Algonquin Tariff, the following language will be included as a Whereas clause in Customer's Agreement:*** "The service provided to Customer under this Agreement will utilize capacity that was acquired by Customer as Interim Capacity pursuant to the provisions of Section 2.6 of the General Terms and Conditions of the Algonquin Tariff."]

NOW THEREFORE, in consideration of the premises and of the mutual covenants herein contained, the parties do agree as follows:

1. Algonquin shall deliver and Customer shall take and pay for service pursuant to the terms of this Agreement and subject to Algonquin's Rate Schedule ERS and the General Terms and Conditions of Algonquin's Tariff, which are incorporated herein by reference and made a part hereof.

   [***In the event that a precedent agreement for a new or an expansion project contains credit provisions applicable to Customer's capacity related to such project, the following language shall be included in Customer's Service Agreement.*** "The credit requirements applicable to this Agreement are set forth in that certain Precedent Agreement dated ___________ between Algonquin and Customer related to this Agreement."]

2. The Maximum Daily Transportation Quantity (MDTQ) for transportation service under this Agreement and any right to increase or decrease the MDTQ during the term of this Agreement are listed on Exhibit C attached hereto. The Maximum Daily Injection Quantity (MDIQ), Maximum Storage Quantity (MSQ), and Maximum Daily Withdrawal Quantity (MDWQ) for the storage service under this Agreement, and any right to increase or decrease the MDIQ, MSQ or MDWQ during the term of this Agreement are listed on Exhibit D attached hereto. The Primary Point(s) of

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Receipt, Maximum Daily Receipt Obligation (MDRO), Base Flow Path, if applicable, and Base Flow Path Quantity, if applicable, are listed on Exhibit A attached hereto. The Primary Point(s) of Delivery, Maximum Daily Delivery Obligation (MDDO), and Enhanced Maximum Hourly Transportation Quantity (Enhanced MHTQ), if applicable, are listed on Exhibit B attached hereto. Exhibit(s) A, B, C and D are incorporated herein by reference and made a part hereof.

3. This Agreement shall be effective on ___________ [this blank may include a date certain, a date either earlier or later than a specified date certain based on the completion of construction of facilities necessary to provide service under the Agreement, a date set forth in or established by a relevant order from the Federal Energy Regulatory Commission or a commencement date as defined in a precedent agreement between Customer and Algonquin] and shall continue for a term ending on and including ___________ [or, when applicable, "shall continue for a term of ____ years"] ("Primary Term") and shall continue to be effective from _____________ to _____________ thereafter [***In the event that the capacity was awarded as Interim Capacity pursuant to Section 2.6 of the General Terms and Conditions of the Algonquin Tariff, the following phrase will be included in Customer's Agreement:*** ",but in no event beyond _________,"] unless and until terminated by Algonquin or Customer upon prior written notice of at least _______[not less than 1 year for agreements with a primary term of more than 1 year; for service agreements with both a primary term and notice period of exactly one (1) year, the notice must be submitted within ten (10) Business Days of the beginning of the primary term of the service agreement, and at least one (1) year for subsequent notices for such service agreement; and otherwise mutually agreeable]. [In the event that Algonquin and Customer agree to a fixed term, the evergreen and notice of termination language shall be omitted from Customer's Agreement.] This Agreement may be terminated at any time by Algonquin in the event Customer fails to pay part or all of the amount of any bill for service hereunder and such failure continues for thirty days after payment is due; provided Algonquin gives ten days prior written notice to Customer of such termination and provided further such termination shall not be effective if, prior to the date of termination, Customer either pays such outstanding bill or furnishes a good and sufficient surety bond or other form of security reasonably acceptable to Algonquin guaranteeing payment to Algonquin of such outstanding bill; provided that Algonquin shall not be entitled to terminate service pending the resolution of a disputed bill if Customer complies with the billing dispute procedure currently on file in Algonquin's Tariff. Any portions of this Agreement necessary to correct or cash-out imbalances under this Agreement as required by the General Terms and Conditions of Algonquin's Tariff shall survive the other parts of this Agreement until such time as such balancing has been accomplished.

If this Agreement qualifies as a "ROFR Agreement" as defined in the General Terms and Conditions of Algonquin's Tariff, the provision of a termination notice by either Customer or Algonquin, pursuant to the preceding paragraph, a notice of partial reduction in Maximum Daily Transportation Quantity, Maximum Daily Injection Quantity, Maximum Storage Quantity, and Maximum Daily Withdrawal Quantity, as applicable, pursuant to Exhibit C or D, as applicable, or the expiration of this Agreement of its own terms triggers Customer's right of first refusal under Section 9 of the General Terms and Conditions of Algonquin's Tariff.

[***In the event that the capacity was awarded as Interim Capacity pursuant to Section 2.6 of the General Terms and Conditions of the Algonquin Tariff, the previous paragraph will be replaced with the following language:*** "This Agreement does not qualify as a ROFR Agreement, as such term is defined in Section 1 of the General Terms and Conditions of the Algonquin Tariff."]

4. Maximum rates, charges, and fees shall be applicable to service pursuant to this Agreement except during the specified term of a discounted rate or a Negotiated Rate to which Customer and Algonquin have agreed. Provisions governing such discounted rate shall be as specified in the Discount Confirmation to this Agreement. Provisions governing such Negotiated Rate and term shall be as specified on an appropriate Statement of Negotiated Rates filed, with the consent of Customer, as part of Algonquin's Tariff. It is further agreed that Algonquin may seek authorization from the Commission and/or other appropriate body at any time and from time to time to change any rates, charges or other provisions in the applicable Rate Schedule and General Terms and Conditions of Algonquin's Tariff, and Algonquin shall have the right to place such changes in effect in accordance with the Natural Gas Act. Nothing contained herein shall be construed to deny Customer any rights it may have under the Natural Gas Act, including the right to participate fully in rate or other proceedings by intervention or otherwise to contest increased rates in whole or in part.

5. Unless otherwise required in the Tariff, all notices shall be in writing and shall be considered duly delivered when mailed to the applicable address below or transmitted via facsimile. Customer or Algonquin may change the addresses or other information below by written notice to the other without the necessity of amending this Agreement:

   Algonquin:

   Customer:

6. The interpretation and performance of this Agreement shall be in accordance with the laws of the Commonwealth of Massachusetts, excluding conflicts of law principles that would require the application of the laws of a different jurisdiction.

7. This Agreement supersedes and cancels, as of the effective date of this Agreement, the contract(s) between the parties hereto as described below, if applicable:

   [None or an appropriate description]

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IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed by their respective Officers and/or Representatives thereunto duly authorized to be effective as of the date stated above.

CUSTOMER: ____________________	ALGONQUIN GAS TRANSMISSION, LLC
By:___________________________	By:___________________________
Title:__________________________	Title:__________________________

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

Exhibit A

Point(s) of Receipt

Dated: ____________

To the service agreement under Rate Schedule ERS dated ____________ between Algonquin Gas Transmission, LLC (Algonquin) and _________________________ (Customer) concerning Point(s) of Receipt.

Exhibit A Effective Date: __________

Primary Point of Receipt	Maximum Daily Receipt Obligation	Maximum Receipt Pressure
[Base Flow Path]		[Base Flow Path Quantity]

[Notice: Additional information may be included where the Base Flow Path cannot be clearly identified

from the Maximum Daily Receipt Obligation(s) [MDRO(s)] and/or aggregate MDRO(s), the Base Flow Path set forth on Exhibit A of Customer's ERS service agreement, and the Maximum Daily Delivery Obligation(s) (MDDO(s)) and/or aggregate MDDO(s) set forth on Exhibit B of Customer's ERS Service Agreement.]

[Notice: The sum of the Maximum Daily Receipt Obligations (MDROs) in total across any two or more Primary Points of Receipt may also be further limited by a specified aggregate MDRO ("AMDRO"), as applicable.]

Signed for Identification

Algonquin: ____

Customer: ____

Supersedes Exhibit A Dated ____________________________

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

Exhibit B

Point(s) of Delivery

Dated: ____________

To the service agreement under Rate Schedule ERS dated ____________ between Algonquin Gas Transmission, LLC (Algonquin) and ________________________ (Customer) concerning Point(s) of Delivery.

Exhibit B Effective Date: __________

Primary Point of Delivery	Maximum Daily Delivery Obligation	Minimum Delivery Pressure	[Enhanced MHTQ]

[NOTICE: The sum of the Maximum Daily Delivery Obligations (MDDOs) in total across any two or more Primary Points of Delivery may also be further limited by a specified aggregate MDDO ("AMDDO"), as applicable.

[NOTICE: In the event that Customer and Algonquin have reached an agreement for an Enhanced MHTQ at a Point of Delivery under Customer's ERS Service Agreement, the column heading Enhanced MHTQ will be included in Exhibit B to Customer's ERS Service Agreement.]

Signed for Identification

Algonquin: ____

Customer: ____

Supersedes Exhibit B Dated ____________________________

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

Exhibit C

Transportation Quantities

Dated: ___________

To the service agreement under Rate Schedule ERS dated ___________ between Algonquin Gas Transmission, LLC (Algonquin) and ________________________________ (Customer) concerning transportation quantities.

Exhibit C Effective Date: _________

MAXIMUM DAILY TRANSPORTATION QUANTITY (MDTQ):

Dth	Period

[*In the event that Algonquin and Customer agree upon MDTQs that are not the same for each period specified above, the highest MDTQ will be identified with a footnote using an asterisk and the following accompanying text:* "MDTQ to be utilized in applying the monthly Reservation Charge."]

PARTIAL QUANTITY REDUCTION RIGHTS: Customer elects to partially reduce Customer's Maximum Daily Transportation Quantity by ___________ dth as of _________, or any subsequent anniversary date, upon providing ______ [Notice period to be not less than the notice period required to terminate the entire contract] year(s) prior written notice to Algonquin.

Algonquin and Customer agree that, if this Agreement qualifies as a "ROFR Agreement", (i) the foregoing contractual right to partially reduce Customer's Maximum Daily Transportation Quantity is in addition to and not in lieu of any ROFR right to reduce Customer's Maximum Daily Transportation Quantity on a volumetric basis upon termination or expiration of this Agreement and (ii) only the partial reduction pursuant to the foregoing contractual right to partially reduce Customer's Maximum Daily Transportation Quantity is subject to the ROFR procedures specified in the General Terms and Conditions of Algonquin's Tariff and Customer may retain the balance of the Maximum Daily Transportation Quantity without being subject to the ROFR procedures.

Signed for Identification

Algonquin: ______________________________________

Customer: ______________________________________

Supersedes Exhibit C Dated __________________________

FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

Exhibit D

Storage Quantities

Dated: ____________

To the service agreement under Rate Schedule ERS dated ____________ between Algonquin Gas Transmission, LLC (Algonquin) and ________________________________ (Customer) concerning storage quantities.

Exhibit D Effective Date: __________

MAXIMUM STORAGE QUANTITY (MSQ): __________ Dth

MAXIMUM DAILY INJECTION QUANTITY (MDIQ): __________ Dth
Dth Period

MAXIMUM DAILY WITHDRAWAL QUANTITY (MDWQ): __________ Dth
Dth Period

PARTIAL QUANTITY REDUCTION RIGHTS: Customer elects to partially reduce Customer's MDIQ by ____________ dth, MSQ by ____________ dth and MDWQ by ____________ dth, maintaining the existing MDIQ, MSQ and MDWQ relationship, as of __________, or any subsequent anniversary date, upon providing _______ [Notice period to be not less than the notice period required to terminate the entire contract] year(s) prior written notice to Algonquin.

Algonquin and Customer agree that, if this Agreement qualifies as a "ROFR Agreement", (i) the foregoing contractual right to partially reduce Customer's Maximum Storage Quantity is in addition to and not in lieu of any ROFR right to reduce Customer's Maximum Storage Quantity on a volumetric basis upon termination or expiration of this Agreement and (ii) only the partial reduction pursuant to the foregoing contractual right to partially reduce Customer's Maximum Storage Quantity is subject to the ROFR procedures specified in the General Terms and Conditions of Algonquin's Tariff and Customer may retain the balance of the Maximum Storage Quantity without being subject to the ROFR procedures.

Signed for Identification

Algonquin: ____

Customer: ____

Supersedes Exhibit D Dated ____________________________

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Attachment B
Retail Market Share

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Retail Market Share

ELECTRIC DISTRIBUTION COMPANY	CUSTOMER'S EDC SHARE (PERCENT)
Connecticut Light & Power Co. d/b/a Eversource Energy	21.7%
United Illuminating Company	5.1%
NSTAR Electric Co. d/b/a Eversource Energy	19.6%
Western Massachusetts Elec. Co. d/b/a Eversource Energy	3.4%
Massachusetts Electric Co. d/b/a National Grid	20.0%
Nantucket Electric Co. d/b/a National Grid	0.1%
Unitil Energy Services, Inc. - Massachusetts	0.4%
Central Maine Power Co.	7.9%
Emera Maine	1.4%
Public Service Co. of New Hampshire d/b/a Eversource Energy	7.4%
Unitil Energy Services, Inc. - New Hampshire	1.2%
Liberty Utilities - New Hampshire	0.9%
Narragansett Electric Co. d/b/a National Grid	7.2%
Green Mountain Power Company	3.7%
Total	100%

*2014 ISONE Annual Twelve Month Average of Monthly Peak Network Loads

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Attachment C
Negotiated Rate Agreement

ALGONQUIN GAS TRANSMISSION, LLC
5400 Westheimer Court
Houston, TX 77056-5310
713.627.5400 main

Mailing Address:
P.O. Box 1642
Houston, TX 77251-1642

Spectra Energy Partners.

February 15th 2016

Edna Karanian
Director, Gas Supply
Public Service Company of New Hampshire d/b/a Eversource Energy
107 Selden Street
Berlin, Connecticut 06037

Re: Rate Schedule ERS Service Agreement (Contract No. ______) – Negotiated Rate

Dear Ms. Karanian:

By this transmittal letter, Algonquin Gas Transmission, LLC ("Algonquin") and Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH") are implementing a negotiated rate applicable to service under the above-referenced Rate Schedule ERS Service Agreement.

Algonquin and PSNH hereby agree that the provisions on the attached *Pro Forma* Statement of Negotiated Rates reflect the terms of their agreement, including the effectiveness of the negotiated rate. After execution of this letter by both Algonquin and PSNH, Algonquin shall file a Statement of Negotiated Rates with the Federal Energy Regulatory Commission ("Commission") containing rate-related provisions identical to those provisions on the attached *Pro Forma* Statement of Negotiated Rates in accordance with Section 46 of the General Terms and Conditions of the Algonquin tariff.

If the foregoing accurately sets forth your understanding of the matter covered herein, please so indicate by having a duly authorized representative sign in the space provided below and returning an original signed copy to the undersigned.

Sincerely,

William T. Yardley
President

ACCEPTED AND AGREED TO
THIS 15th DAY OF FEBRUARY, 2016

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A EVERSOURCE ENERGY

Name: James G. Daly
Title: Vice President Energy Supply

STATEMENT OF NEGOTIATED RATES 1/2/3/4/5/6/7/8/

Customer Name: Public Service Company of New Hampshire d/b/a Eversource Energy

Service Agreement: [INSERT CONTRACT NUMBER]

Term of Negotiated Rate: The term of this negotiated rate commences on the Phase 1 Service Commencement Date (as defined in the Precedent Agreement between Pipeline and Customer) of Contract No. [INSERT CONTRACT NUMBER] and continues for the Primary Term (as such term is defined in the Precedent Agreement and Contract No. [INSERT CONTRACT NUMBER]) and any evergreen term thereof. 6/ In the event that Customer exercises its option to extend the Primary Term for [redacted] negotiated reservation rate as reflected in item (iii) under Extension Reservation Rate below, the term of this Negotiated Rate shall extend at such new negotiated rate for such extended term and any evergreen term thereof.

Rate Schedule: ERS [Access Northeast Project]

MDTQ: 7/

[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
[redacted] on the Phase 4 Service Commencement Date

MSQ: [redacted] on the Phase [redacted] Service Commencement Date 7/

Reservation Rate: Customer shall pay a negotiated reservation rate of [redacted] per month of Customer's MDTQ under Contract No. [INSERT CONTRACT NUMBER] during the Primary Term and any evergreen term of such Primary Term. 3/5/8/

Extension Reservation Rate:

(A) In the event that Customer exercises its option to extend the Primary Term for either [redacted] the rate during any such extended term and any evergreen term of such extended term, shall be chosen by Customer at the time Customer exercises its option to extend from one of the following: [redacted]

[redacted]

(B) [redacted]

(C) [redacted]

(D) [redacted]

(E) [redacted]

[redacted]

Commodity Charge: Customer shall pay the applicable maximum recourse commodity and usage rates, as reflected on the currently effective Statement of Rates for Pipeline's Rate Schedule ERS for the Project; provided, however, that such rates shall not include any allocation of fixed costs. 5/

Other Charges: 5/

Non-Storage Primary Receipt Point: 7/

Mahwah (Meter No. 00201)
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date

Ramapo (Meter No. 00214)
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date

Brookfield (Meter No. 00251)
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date

Storage Primary Receipt Point(s): 7/

Acushnet (Meter No. [TBD])
[redacted] on the Phase [redacted] Service Commencement Date

Primary Delivery Points: 7/

Connecticut
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
[redacted] on the Phase 4 Service Commencement Date

Massachusetts
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
[redacted] on the Phase 4 Service Commencement Date

SEMA – G System

[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
[redacted] on the Phase 4 Service Commencement Date

Maine

[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
[redacted] on the Phase 4 Service Commencement Date

Recourse Rate(s): The Recourse Rate(s) applicable to this service is the applicable maximum rate(s) stated on Pipeline's Statement of Rates for Rate Schedule ERS [Access Northeast Project] at the applicable time.

FOOTNOTES:

1/ This negotiated rate agreement is part of a non-conforming Service Agreement.

2/ This negotiated rate shall apply only to transportation service under Contract No. [INSERT CONTRACT NUMBER], up to Customer's specified MDTQ, using the Primary Receipt Point and Primary Delivery Point designated herein, and any secondary receipt and delivery points available under Rate Schedule ERS; provided if Customer changes its primary points listed above (or the MDROs or MDDOs associated with such points), pursuant to the provisions of the Pipeline's FERC Gas Tariff, Pipeline shall have the option to terminate this negotiated rate by providing Customer with written notice of Pipeline's intent to terminate the negotiated rate and, in such case, this negotiated rate shall terminate and Pipeline's maximum recourse rate for Rate Schedule ERS for the Project shall apply for the remaining term of the Service Agreement, unless and until otherwise agreed in writing between Customer and Pipeline.

3/ [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4/ Pipeline and Customer agree that Contract No. [INSERT CONTRACT NUMBER] is a ROFR Agreement.

5/ Customer shall pay (i) the applicable Fuel Reimbursement Quantity ("FRQ") under Pipeline's Rate Schedule ERS for the Project, which shall include fuel use loss related to liquefaction and compression for the storage facilities and (ii) the applicable Annual Charge Adjustment and all other charges and surcharges applicable to Rate Schedule ERS for the Project, including electric power costs and other variable operating costs for the storage facilities. Customer shall also pay any future surcharge or additional usage charge pursuant to any FERC-approved cost recovery mechanism of general applicability implemented in a generic proceeding or in a Pipeline specific proceeding, or any other recovery mechanism for the recovery of direct or indirect costs not reflected in Pipeline's FERC approved Rate Schedule ERS rates for the Project at the time of execution of this negotiated rate, including but not limited to such costs related to pipeline safety or environmental compliance costs associated with Pipeline's operation.

6/ If the term of Contract No. [INSERT CONTRACT NUMBER] renews for one or more twelve (12) month evergreen period(s) at the Negotiated Reservation Rate, then the term of this negotiated rate shall be extended for such evergreen period(s).

7/ The MDTQs, MSQ, MDROs, MDDOS, MDIQ, and MDWQ may be revised in accordance with Paragraph 3(a) of the Precedent Agreement.

8/ **Most Favored Nations**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

(e) Waiver

Nothing in this footnote 8 constitutes a waiver of either party's right to seek regulatory and/or judicial relief if a party acts in a manner that is inconsistent with its obligations as set forth in this footnote.

Attachment D
Form of Letter of Credit

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ATTACHMENT D

IRREVOCABLE STANDBY LETTER OF CREDIT

Letter of Credit No:__________

Date:________________, 20__

Date of Expiry: __________, 20__

Beneficiary:
[Spectra entity name]
5400 Westheimer Court
Houston, TX 77056

Account Party:
(Complete Legal Name)
(Address)
(City, State, Zip)

Attn: Credit Director

[Name of Bank] ("Issuing Bank") hereby establishes this Irrevocable and Transferable Standby Letter of Credit No. ________ in favor of [Spectra entity name] ("Beneficiary") for the account of [Account Party Name] ("Account Party") in connection with that certain Precedent Agreement between Account Party and Beneficiary, dated [ ], 2016 (the "Precedent Agreement"), and the related firm transportation service agreement between Account Party and Beneficiary (the "Service Agreement"), for the aggregate amount of up to (*dollar amount*) available to Beneficiary by presenting sight draft(s) to Issuing Bank when accompanied by a signed and dated statement by an authorized representative of Beneficiary certifying one or more of the following, as applicable:

1. "The amount drawn herein is to satisfy obligations of Account Party between Beneficiary and Account Party. Wherefore, the undersigned Beneficiary does hereby demand payment of $__________. Beneficiary further certifies that supporting documents when required were presented to Account Party and that Account Party has not satisfied its obligations." And / or

2. "This Letter of Credit will expire in less than thirty (30) days and Beneficiary has not received an extension of said Letter of Credit or other acceptable replacement collateral from Account Party. Wherefore, the undersigned Beneficiary does hereby demand payment of $__________. Upon timely receipt of an amendment extending this Letter of Credit, this drawing is to be considered automatically rescinded." And / or

3. "Issuing Bank 's lowest long-term senior unsecured debt rating no longer meets or exceeds "A-" by Standard & Poor's Rating Group and "A3" by Moody's Investor Services, Inc., and Account Party has not caused a replacement Letter of Credit from an alternate financial institution acceptable to Beneficiary to be issued to Beneficiary. Wherefore, the undersigned Beneficiary does hereby demand payment of $________________."

SPECIAL TERMS AND CONDITIONS

1. Partial and multiple drawings are allowed hereunder. The amount that may be drawn by Beneficiary under this Letter of Credit shall be automatically reduced by the amount of any payments made through Issuing Bank referencing this Letter of Credit.

2. This Letter of Credit shall automatically extend without amendment for periods of one year each from the present or any future expiry date unless Issuing Bank notifies Beneficiary in writing at least sixty (60) days prior to such present or future expiry date, as applicable, that Issuing Bank elects not to further extend this Letter of Credit.

3. This Letter of Credit is transferable without charge any number of times, but only in the amount of the full unutilized balance hereof and not in part and with the approval of Account Party which consent shall not be unreasonably withheld, conditioned or delayed.

4. The term "Beneficiary" includes any successor by operation of law of the named beneficiary to this Letter of Credit, including, without limitation, any liquidator, any rehabilitator, receiver or conservator.

5. Presentations for drawing may be delivered in person, by mail, by express delivery, or by facsimile.

6. All Bank charges are for the account of Account Party.

7. Article 36 under UCP 600 is modified as follows: If the Letter of Credit expires while the place for presentation is closed due to events described in said Article, the expiry date of this Letter of Credit shall be automatically extended without amendment to a date thirty (30) calendar days after the place for presentation reopens for business.

Issuing Bank hereby agrees with Beneficiary that documents presented for drawing in compliance with the terms of this Letter of Credit will be duly honored upon presentation at Issuing Bank's counters if presented on or before the expiry date.

Unless otherwise expressly stated herein, this Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits ("UCP"), 2007 Revision, International Chamber of Commerce Publication No. 600. Matters not covered by the UCP shall be governed and construed in accordance with the laws of the state of New York.

ISSUING BANK SIGNATURE

Attachment E
Form of Guaranty

EXECUTION COPY

Attachment E

GUARANTY

This Guaranty ("Guaranty"), dated as of _____________, is made by _____________________, a [state and corporate structure] ("Guarantor"), in favor of ____________ a [state & corporate structure] ("Beneficiary").

WHEREAS, from time to time, ________________, a ________________ [state and corporate structure] ("Counterparty"), and Beneficiary have entered into that certain precedent agreement dated _______ ("Precedent Agreement"), as may be amended from time to time and that certain service agreement dated ______ ("Service Agreement"), as may be amended from time to time (both Precedent Agreement and Service Agreement are collectively referred as the "Agreement");

WHEREAS, Counterparty is a wholly-owned subsidiary of Guarantor; and Guarantor will directly or indirectly benefit from the Agreement to be entered into between Counterparty and Beneficiary; and

WHEREAS, as an inducement to Beneficiary to enter into the Agreement, Guarantor has agreed to provide this Guaranty; and

WHEREAS, Guarantor has agreed to execute and deliver this Guaranty with respect to Counterparty's payment obligations under the Agreement:

NOW THEREFORE, in consideration of the premises, Guarantor hereby agrees as follows:

1. **Guaranty**. Guarantor hereby absolutely, irrevocably and unconditionally guarantees the timely payment when due of Counterparty's payment obligations arising under any Agreement, as such Agreement may be amended or modified from time to time, together with any interest thereon and fees and costs of collection (including attorney's fees and court costs) in connection therewith ("Obligation"). In the event Counterparty defaults in the payment of any of the Obligation, within ten (10) days after receiving written notice from Beneficiary, Guarantor shall make such payment or otherwise cause same to be paid. This Guaranty may be enforced by Beneficiary at any time without the necessity of first resorting to or exhausting any other security or collateral. All amounts payable by Guarantor hereunder shall be in freely transferable funds.

2. **Effectiveness**. This Guaranty is effective as of the date set forth above and is a continuing guaranty which shall remain in full force and effect throughout the term of the Agreement, including any extensions or renewals thereof, until Guarantor has completely fulfilled the Obligation. If at any time during the effectiveness of this Guaranty, Guarantor no longer qualifies as Creditworthy as defined in Paragraph XX of the Precedent Agreement, Guarantor shall, or shall cause Counterparty to, immediately provide the collateral specified in Paragraph XX(X) of the Precedent Agreement.

3. **Waivers.** (a) Guarantor waives any right to require as a condition to its obligations hereunder any of the following should Beneficiary seek to enforce the obligations of Guarantor:

(i) presentment, demand for payment, notice of dishonor or non-payment, protest, notice of protest, or any similar type of notice;

(ii) any suit be brought against, or any other action be brought against, or any notice of default or other similar notice be given to, or any demand be made upon Counterparty or any other person or entity;

(iii) notice of acceptance of this Guaranty, of the creation or existence of the Obligation, and/or any action by Beneficiary in reliance hereon or connection herewith;

(iv) notice of entering into any Agreement between Counterparty and Beneficiary, and/or any amendments, supplements or modifications thereto, or any waiver of consent under any Agreement, including waiver of the payment and performance of the Obligation thereunder; and/or

(v) notice of any increase, reduction or rearrangement of Counterparty's Obligation under any Agreement, or any extension of time for payment of any amounts due Beneficiary under any Agreement.

(b) Guarantor also waives the right to require, substantively or procedurally, that a judgment has been previously rendered against Counterparty or any other person or entity, or that Counterparty or any other person or entity be joined in any action against Guarantor.

4. **Assignment.** Guarantor shall not assign its duties hereunder without the prior written consent of Beneficiary. Beneficiary shall be entitled to assign its rights hereunder in its sole discretion upon prior written notice to Guarantor. Any assignment without such prior written consent or notice, as applicable, shall be null and void and of no force or effect.

5. **Notice.** All demands, notices or other communications to be given by any party to another must be in writing and shall be deemed to have been given when delivered personally or otherwise actually received or on the third (3rd) day after being deposited in the United States mail if registered or certified, postage prepaid, or one (1) day after delivery to a nationally recognized overnight courier service, fee prepaid, return receipt requested, and addressed as follows:

Guarantor's Name & Address	Beneficiary's Name & Address
____________________	____________________
____________________	5400 Westheimer Court
____________________	Houston, TX 77056
____________________	Attn: Credit Director
____________________	Phone: 713-627-5446
	Fax: 713-989-1717

or such other addresses as they may change from time to time by giving prior written notice to the other party.

6. **Applicable Law.** THIS GUARANTY SHALL IN ALL RESPECTS BE GOVERNED BY, ENFORCED UNDER AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK.

7. **Effect of Certain Events.** Guarantor agrees that its liability hereunder will not be released, reduced, impaired or affected by the occurrence of any one or more of the following events:

(i) the insolvency, bankruptcy, reorganization, or disability of Counterparty;

(ii) the renewal, consolidation, extension, modification or amendment from time to time of the Agreement;

(iii) the failure, delay, waiver, or refusal by Beneficiary to exercise any right or remedy held by Beneficiary with respect to the Agreement;

(iv) the sale, encumbrance, transfer or other modification of the ownership of Counterparty or the change in the financial condition or management of Counterparty; or

(v) the settlement or compromise of any Obligation.

8. **Representations and Warranties**. Guarantor hereby represents and warrants the following:

(i) Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty;

(ii) the execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene Guarantor's constitutional documents or any contractual restriction binding on Guarantor or its assets; and

(iii) this Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other similar laws and to general principles of equity.

9. **Subrogation**. Until all amounts which may be or become payable under the Agreement have been irrevocably and indefeasibly paid in full, Guarantor shall not by virtue of this Guaranty be subrogated to any rights of Counterparty or claim in competition with Beneficiary against Counterparty in connection with any matter relating to or arising from the Obligation or this Guaranty. If any amount shall be paid to Guarantor on account of such subrogation rights at any time before all of the Obligation has been irrevocably paid in full, such amounts shall be held in trust for the benefit of Beneficiary and shall promptly be paid to Beneficiary to be applied to the Obligation.

10. **Amendment**. No term or provision of this Guaranty shall be amended, modified, altered, waived, supplemented or terminated unless first agreed to by Guarantor and Beneficiary and then set forth in a written amendment to this Guaranty.

11. **Counterparts**. This Guaranty may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one document.

12. **Entire Agreement**. This Guaranty embodies the entire agreement and understanding between Guarantor and Beneficiary regarding payment of the Obligation under the Agreement and supersedes all prior agreements and understandings relating to the subject matter hereof.

IN WITNESS WHEREOF, Guarantor has executed this Guaranty effective as of the date first herein written.

GUARANTOR' S NAME

By:________________________________

Name:______________________________

Title:_______________________________

EXECUTION COPY

Attachment F
Pro Forma Schedule

REDACTED

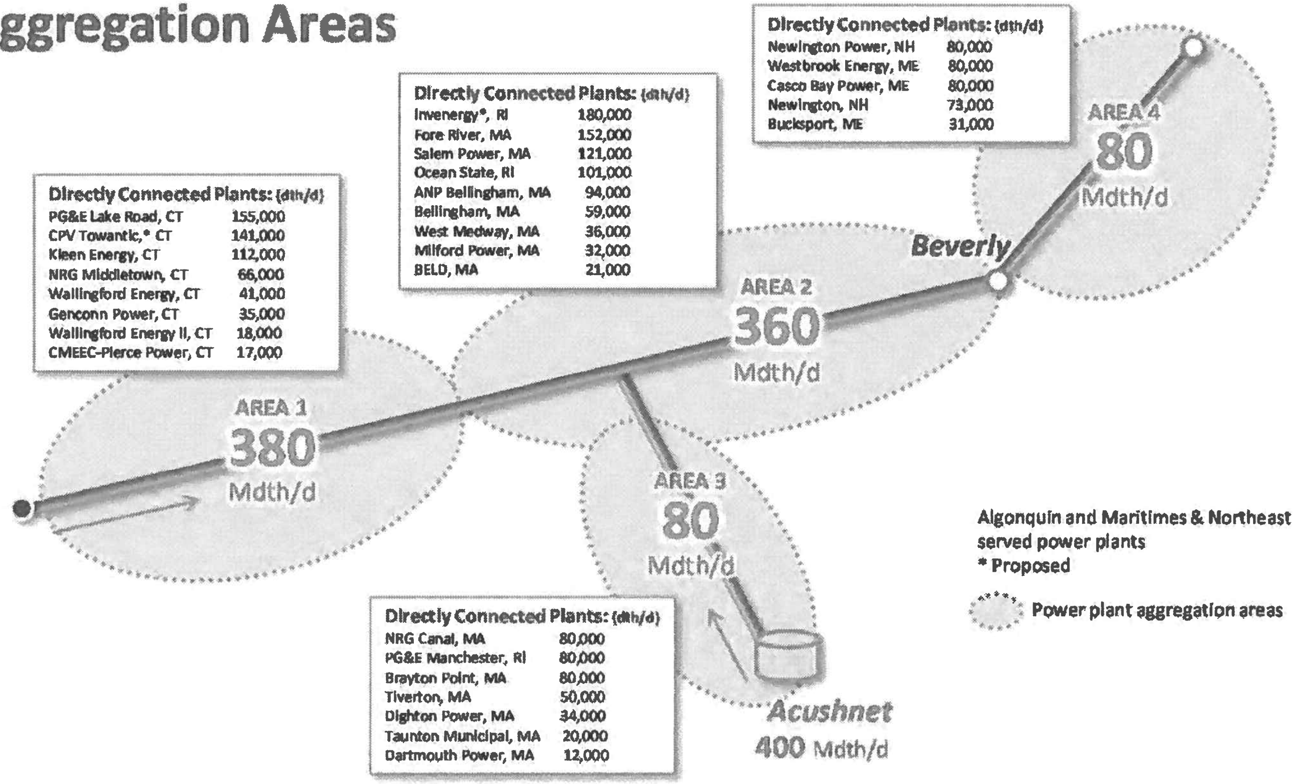
Deadline Description	Agreement Section	Agreement Provision	Calendar Deadline[1]
[redacted]			

[1] Assumes Phase 1 Service Commencement Date of November 1, 2018. Date to be updated based on actual Service Commencement Date.

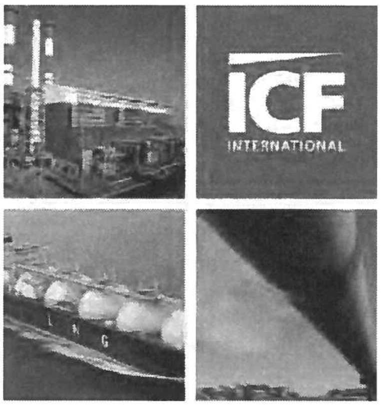
EXECUTION COPY

Attachment G
Aggregation Areas

Aggregation Areas



Each Rate Schedule ERS customer will have the ability to deliver natural gas to each electric power generator within an aggregation area up to such customer's pro rata share of the applicable capacity limit shown in the figure above. For the electric power generators identified as proposed or future generation projects, those delivery points will only become available, subject to Section 6.3 of Rate Schedule ERS, once the generator's facilities and the interconnection facilities are placed into service.



Access Northeast Project - Reliability Benefits and Energy Cost Savings to New England Consumers

Prepared for

NSTAR Electric Company
Western Massachusetts Electric Company
Public Service Company of NH
Connecticut Light and Power Company
Each d/b/a Eversource Energy (Eversource)

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

December 18, 2015

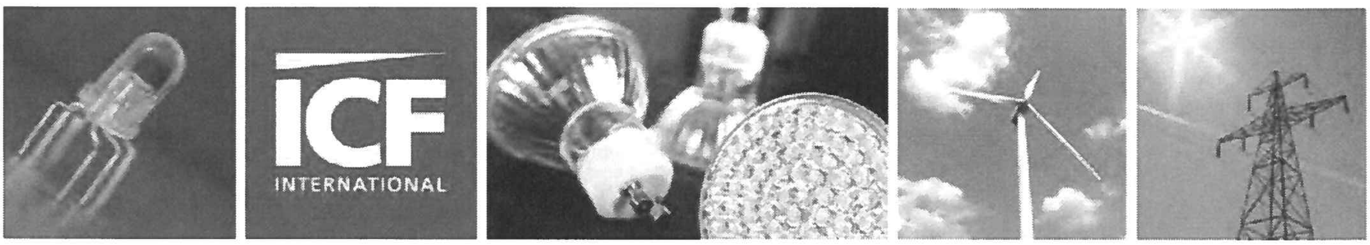


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Table of Contents

Executive Summary

ICF International (ICF) was engaged by Eversource to provide an independent assessment of the potential impacts of the proposed Access Northeast gas infrastructure project (Access Northeast) on New England's natural gas and electric markets. In particular, ICF's analysis focuses on the impact that new infrastructure may have on regional gas and electricity prices, and the associated economic impacts on consumers.

New England has been steadily increasing its reliance on natural gas-fired electricity generation over the past fifteen years. Currently, about 50% of New England's power comes from gas-fired generation, compared to roughly 15%[1] in 2000. Furthermore, the projected retirements of regional nuclear and coal-fired power plants is expected to result in the construction of new gas-fired generation.

Many observers, including the ISO-NE and ICF, have noted that New England faces the risk of persistent and growing natural gas supply constraints without any new sources of capacity. Of particular concern is whether the network of gas production, pipelines, and storage capacity serving New England will be adequate to supply power generators under winter gas demand conditions.[2] A 2014 ICF study for ISO-NE indicates a need for up to 1.1 Bcf/d of additional gas supply by 2020 to meet projected power plant fuel requirements on a design day.[3] This equates to roughly 5,700 MW[4] of capacity, or up to approximately 30% of the region's gas generation capacity. Without changes to the current structure of the regional energy markets, such risks could disproportionately affect electricity markets, and thereby negatively affect economic and potential service reliability for all New England consumers.

Access Northeast could significantly enhance ISO-NE's electric system reliability by directly providing firm natural gas fuel for gas fired power generators and help New England potentially avoid costly load shedding measures under extreme circumstances.

ICF's analysis suggests that Access Northeast would generate significant cost savings to New England electric consumers by reducing the price of natural gas delivered to New England utilities and subsequently, wholesale energy prices in all New England states. ICF estimates that on average, under normal weather conditions, Access Northeast would save New England electric consumers $1.4 to $1.9 billion per year[5] and under design winter conditions[6] with a nuclear outage, $3.1 billion per year, as detailed in Table 1. About 80% of the benefits accrue to consumers in Massachusetts, Connecticut and New Hampshire.

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[1] http://www.iso-ne.com/static-assets/documents/2015/03/icf_isone_van_welie.pdf slide 7.

[2] New England residential and commercial demand is the highest during the peak winter months of December, January and February and LDCs will draw heavily on existing natural gas infrastructure.

[3] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II, page 21, Exhibit 4-6.

[4] Ibid.

[5] The cost savings discussed throughout this report do not include potential revenues from capacity released into the market.

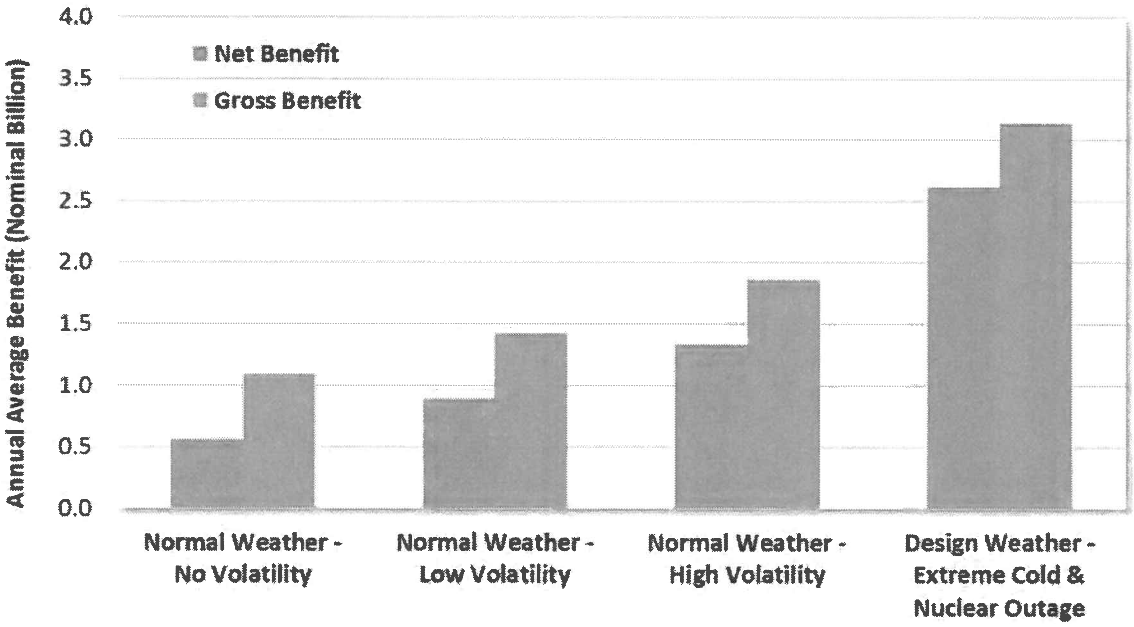
[6] Design winter conditions are dependent on how companies define it, but it is generally a very cold winter with a coldest day, based on observed weather over the last 20-30 years.

Table 1: Annual Access Northeast Benefits and Cost Summary (Average of 2019-2035)

	New England (Nominal Billion)	MA (Nominal Million)	CT (Nominal Million)	NH (Nominal Million)
Normal Weather (Low Volatility)	$1.4	$630	$370	$140
Normal Weather (High Volatility)	$1.9	$830	$480	$185
Design Weather (2021-2022)	$3.1	$1,390	$780	$270
Costs[7]	$0.5	TBD	TBD	TBD
Net Benefits (Low-High Volatility)	$0.9 - $1.3	--	--	--

Source: ICF

Figure 1: Annual Average Gross and Net Benefits for New England under Different Scenarios



Source: ICF

Key observations and conclusions are summarized below.

Outlook for New England Gas Market

<u>New England needs incremental firm natural gas supplies for the electric sector during winter months due to increasing gas consumption for power generation</u>

In recent years, New England has steadily increased its reliance on natural gas fired generation as coal and nuclear power plants have been retired. This growing reliance on natural gas is expected to continue

[7] Estimated demand charge to be paid by New England EDCs for Access Northeast capacity, provided by Eversource.

during the next few years with the retirement of additional nuclear, coal, and oil-fired capacity (e.g., Vermont Yankee, Brayton Point, Mount Tom, and Pilgrim) and the addition of new gas-fired capacity (Footprint Power). Cumulative firm retirements of nuclear, coal and older oil/gas units in New England are expected to reach 4,150 MW by 2019.[8] In the future, the New England electricity market will be increasingly served by a combination of natural gas, renewable and energy efficiency sources. ICF projections assume that all states will achieve their stated Renewable Portfolio Standards ("RPS") targets on schedule.[9] Growth in electric load will be partially offset by energy efficiency and passive demand response gains, reducing projected growth in net energy load to only 0.04% per year through 2035. Notwithstanding these increases in renewables and energy efficiency, ICF projects that the region will require approximately 1,740 MW of new gas-fired generating capacity by 2019, further increasing power sector gas demand. As a result, the demand for natural gas from the power sector has increased, with the growth rates being greatest in the winter heating season when traditional heating demand for natural gas is also at its peak.

Diminishing New England gas supply sources increase consumer exposure to non-firm gas supplies

Historically, a portion of New England's gas supplies have come from gas fields in offshore Atlantic Canada and liquefied natural gas (LNG) cargoes delivered to regional import terminals. Both of these supply sources have diminished in recent years, which will require New England to replace these sources simply to preserve the supply/demand status quo.

The Maritimes and Northeast (M&N) Pipeline was originally constructed to bring Sable Island offshore gas production to markets in Eastern Canada and New England. However, the development of Sable Island production was less than originally anticipated, and production from that field has been declining since 2008.[10] A second offshore field, Deep Panuke, began production in October 2013. At its peak, Deep Panuke was expected to produce about 300 MMcf/d, but there have been numerous technical problems that have intermittently halted production, and over the past year production has averaged less than 100 MMcf/d.[11]

New England's access to gas supplies has become further constrained by the reduced frequency of firm cargoes at the regions' LNG import terminals. LNG is a global commodity and importers to New England largely operate without firm contracts to sell to New England buyers, instead preferring to seek the highest prices available wherever that may be. The Canaport LNG import terminal in New Brunswick has also provided gas supplies to New England. In 2013, Repsol S.A., the majority owner and manager of the Canaport terminal, sold its long-term LNG supply contracts and ship charters, leaving Canaport with minimal firm supply contracts. LNG imports also come directly into New England via the Everett terminal.

[8] Retirements considered firm if they are permanently delisted units or if they have submitted a non-price retirement request that ISO-NE has accepted.
[9] The implications for generating sources under the recently announced and revised Clean Power Plan are still being assessed.
[10] http://www.cnsopb.ns.ca/sites/default/files/pdfs/monthly_production_plots.pdf
[11] http://www.cnsopb.ns.ca/sites/default/files/pdfs/dp_monthly_prodution_plot.pdf

Imports to Everett declined by 81% from 2011 to 2014.[12] There are two other offshore LNG import terminals that connect into New England, Neptune and Northeast Gateway. Over the 7 years from 2008 and 2014, the offshore terminals received a total of only 45 Bcf, and Neptune has received no shipments since it initial commissioning in 2010.[13] ICF assumes that LNG imports at Canaport and Everett remain at 2014-2015 winter levels throughout the forecast period based on current firm LNG contracts.

New England would benefit from greater access to the growing production in the Marcellus/Utica basins

The Appalachian Basin was one of the first US oil and gas producing regions, and ICF expects that the Appalachian Basin's role as supplier will continue to grow as production from the Marcellus/Utica shale region increases from its current output of 18 Bcf/d[14] to a projected 42 Bcf/d by 2035. The dramatic increase in low-cost Appalachian Basin gas production has materially altered the relationship of the basin's gas prices to other trading points across the North American market. The price of natural gas in the Appalachian Basin (represented by the Dominion South pricing point) relative to the North American benchmark Henry Hub (Louisiana) price has plummeted nearly $1.50/MMbtu from a premium to a discount of more than $1.00. ICF projections show that, as a result of declining production costs, the discounted spread will widen further to nearly $2.00/MMBtu. At these prices, the Appalachian Basin is among the lowest priced gas supply sources on the continent, and this gas supply is located very close geographically to New England.

Electric Market Benefits from Access Northeast

Access Northeast would significantly reduce the wholesale power costs in New England by reducing congestion and prices for New England's natural gas market.

In a normal weather year, Access Northeast would save New England electric consumers $1.4 billion to $1.9 billion per year

ICF estimates that, on average, Access Northeast would save New England electric consumers $1.4 billion to $1.9 billion per year over the period of 2019 to 2035. For context, ISO-NE reported that "the total value of the region's wholesale electricity markets, including electric energy, capacity, and ancillary services markets, rose…to about $9.9 billion in 2014 … [and electric] energy comprised $8.4 billion of the total."[15] The potential cost savings stem from the highly correlated nature of natural gas prices and wholesale power prices in New England, and the fact that lower gas prices resulting from Access Northeast capacity reduce wholesale power prices. These savings would ultimately extend to all New England electric

[12] U.S. Energy Information Administration, U.S. Natural Gas Imports by Point of Entry, http://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm, accessed October 28, 2015.

[13] U.S. Energy Information Administration, Ibid.

[14] 18 Bcf/d is dry gas output from the Marcellus/Utica basins alone. It does not include any liquids production and conventional production in the Appalachian region. "Wet" gas and conventional production from the area pushes the total above 20 Bcfd.

[15] ISO-NE Press Release on 2014 Annual Markets Report, at http://www.iso-ne.com/static-assets/documents/2015/05/amr14_release_05202015_final.pdf

consumers, including those in the states not directly receiving natural gas from the Access Northeast project.

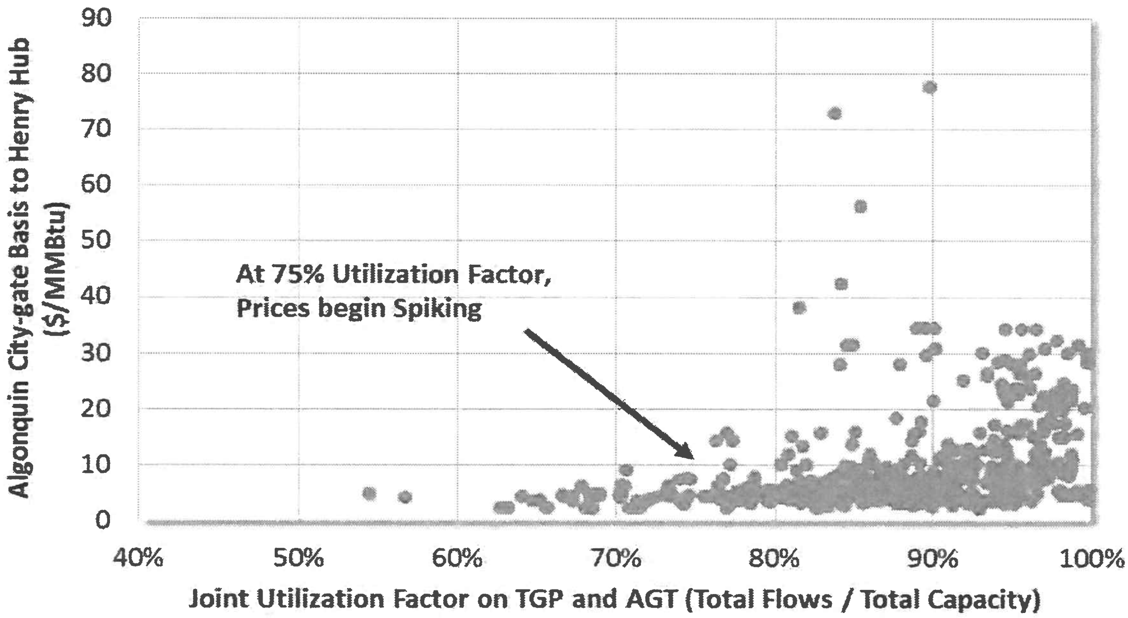
Under design winter weather conditions and a nuclear outage, Access Northeast would save New England electric consumers $2.6 billion over a five month winter period

The consequences of New England's growing dependence on non-firm pipeline capacity for gas-fired generation were made clear in the 2013-2014 winter. During the Polar Vortex episodes, power generation and heating demand for natural gas soared in the Midwest, Northeast, and Mid-Atlantic. Assuming design winter cold conditions, as well as a potential nuclear outage during the winter and higher power demand (ISO-NE's P90 demand forecast), ICF estimates that with Access Northeast, electric consumers would save $2.6 billion between November 2021 and March 2022, which on an annualized basis would be $3.1 billion.

New England wholesale gas and electric prices rise and become more volatile at pipeline capacity load factors well below 100% utilization

During the 2013-2014 winter, daily utilization factors on major inbound pipelines — Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (AGT) —averaged 90% and frequently exceeded 95%. ICF analysis illustrates how traded spot gas prices in New England – and wholesale power prices by extension – can spike and be more volatile when pipeline utilization factor rises above approximately 75% (Figure 2). It is not necessary for the region to experience actual gas capacity deficits for higher costs to materialize.

Figure 2: AGT and TGP Utilization Factor vs. Algonquin City-gates Winter Basis (2011/12 - 2013/14)



Source: Point logic, Ventyx

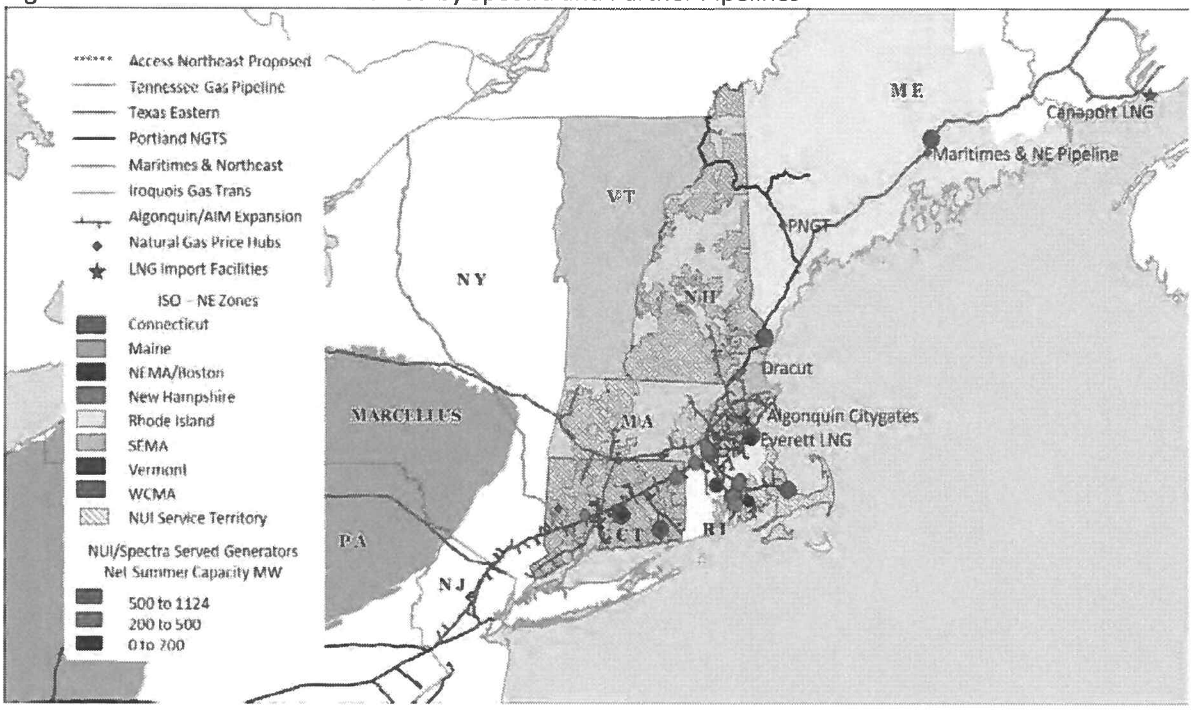
Reliability and Other Benefits from Access Northeast

A pipeline such as Access Northeast will enhance New England's grid reliability, complement the ISO-NE's market improvements to incentivize generation availability

Access Northeast can potentially serve 6,900 MW, or nearly 70 percent of the region's existing natural gas fired power generation capacity interconnected to the pipeline system and operating without backup fuel capability.[16] By providing secure fuel supplies to these generators, Access Northeast could significantly improve electric reliability across the grid and help the region avoid costly load shedding measures under extreme circumstances.

Access Northeast is designed to supply a significant amount of new pipeline capacity to both existing power plants and proposed facilities and will provide access to domestically sourced peaking LNG supply during winter periods.[17] This design will optimize the use of natural gas infrastructure by providing year-round access to more natural gas and, when demand for gas is low (typically, Spring, Summer and Fall) storing this domestic gas in regional LNG facilities to be used by electric generation during the Winter. By providing secure fuel supplies to these generators and LNG facilities, Access Northeast could improve electric reliability across the grid.

Figure 3: Gas Fired Generation Served by Spectra and Partner Pipelines



Source: Ventyx

[16] Data from Spectra Energy, which includes capacity served by ALQ, MN&P and Iroquois.
[17] http://www.spectraenergy.com/content/documents/Projects/NewEngland/Access-Northeast-Project-Brochure.pdf

The ISO-NE has developed a market enhancement that is intended to improve generation availability in order to mitigate the adverse consequences of reliability shortage events. This program is known as "Pay for Performance" (or Performance Incentives "PI") and is planned to be implemented by ISO-NE on June 2018. Once the program is in place, severe penalties ($2,000/MWh increasing to $5,455/MWh over time)[18] will be levied on generation that is not available to run at its credited generation capacity level during a generation resource shortage. As ICF has pointed out, currently there could be insufficient firm fuel for as much as 5,700 MW of generation, which means that during winter shortage events the existing gas fired generation units could incur severe penalties if they are not able to dispatch.[19] The infrastructure solution provided by Access Northeast can provide this fuel to follow the hourly gas load variations of power plants, and thereby help ISO-NE meet its system reliability mandate and help generation avoid the PI shortage penalties.

Access Northeast will support the region's renewable energy goals

New England States have ambitious goals for deployment of renewable generation. Due to the intermittent nature of wind and solar generation, additional quick response resources, such as natural gas combustion turbines, are needed as renewables' share of total generation increases. Access Northeast will provide services that are designed specifically to follow the hourly gas load variations of power plants as electric load and gas fired generation dispatch fluctuates during the day. Access Northeast is also well positioned to provide fuel supplies to ensure that generators have a fuel supply when renewable resources are not generating due to the intermittent and unpredictable nature of the resources.

18 http://www.ourenergypolicy.org/wp-content/uploads/2014/11/ISO_NE_Pay_for_Performance_Initiative.pdf, page 4

19 Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II, page 21, Exhibit 4-6.

Introduction

Study Background

For the past 15 years, New England has been steadily increasing its reliance on natural gas-fired electricity generation. At present, approximately 50% of New England's power comes from gas-fired generation, compared to roughly 15%[20] in 2000. The projected retirements of regional nuclear and coal-fired power plants will result in the construction of new gas-fired generation and continue this trend.

The growth in gas-fired generation raises important questions about the reliability of gas supplies to meet that demand. Central to the issue is New England's reliance on interruptible gas supplies for much of its power generation fuel supply. Unlike LDCs, which contract for firm pipeline and storage services to ensure gas supplies (especially on the coldest days), most gas-fired generators in New England rely on non-firm (or "interruptible") pipeline capacity for their fuel supplies. This practice worked in the past because power sector gas demand was concentrated in the summer months, when interruptible pipeline capacity is widely available. However, gas-fired power plants now provide a high percentage of total electric generation throughout the year, including the winter months when LDC demands are high and interruptible capacity is scarce. As more nuclear and coal plants retire and at least some portion of their capacity is replaced by more gas-fired generation, year-round power sector gas demand will continue to increase, and it will be increasingly difficult to meet power sector gas demand on cold days during peak winter months.

In a recent article for IEEE Power & Energy Magazine on conditions during the winter of 2013/14, ISO-NE stated that "subordinate contracts for gas transport were generally not available to power providers."[21] ISO-NE was able to avoid potential brownouts and blackouts during the winter of 2013/14 through the implementation of a number of measures, most notably its "Winter Reliability Program".[22] However, one of the consequences of constraints on gas supplies has been extremely high and volatile natural gas prices during the winter months. This increases the cost of fuel for electric generators, which results in higher electricity costs for New England consumers. All six New England states rank among the top ten U.S. States with the highest residential electricity rates, averaging 45% higher than the U.S. average.[23]

In 2013, the governors of all six New England states issued a joint statement on natural gas and electric system interdependency, and the need for regional cooperation on energy infrastructure issues.[24] In 2015, the governors again released a joint statement, acknowledging that "New England continues to face significant energy system challenges with serious economic consequences for the region's consumers.

[20] http://www.iso-ne.com/static-assets/documents/2015/03/icf_isone_van_welie.pdf slide 7.

[21] Babula, M. & Petak, K. (2014). The Cold Truth, Managing Gas-Electric Integration: The ISO New England Experience. IEEE Power & Energy Magazine, November/December 2014, pp 20-28.

[22] A collaboration between ISO New England and regional stakeholders, this project focused on developing a short-term, interim solution to filling a projected "reliability gap" of megawatt-hours (MWh) of energy that would be needed in the event of colder-than-normal weather during winter 2013/2014. The solutions included a demand side response program, an oil inventory service, incentives for dual fuel units, and market monitoring changes.

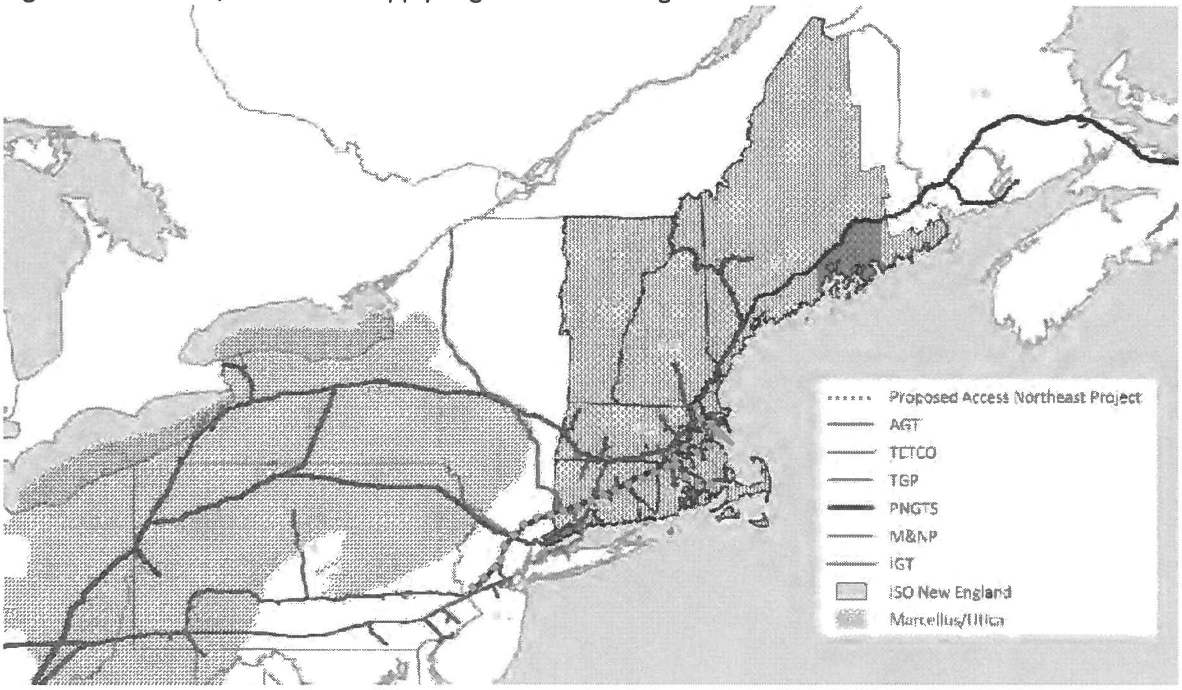
[23] The other states are Hawaii (1), Alaska (4), New York (5) and California (8).

[24] http://nescoe.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf

These challenges require cost-effective solutions to reduce consumer energy costs, strengthen grid reliability and enhance regional economic competitiveness".[25]

New England's natural gas supply deficit occurs against the back drop of a production boom from the Marcellus and Utica shales in the nearby Appalachian Basin in Pennsylvania, West Virginia, and Ohio (Figure 4). ICF expects that the Appalachian Basin will become the biggest natural gas supply basin in North America, with production from the Marcellus/Utica region projected to more than double, reaching 42 Bcf/d by 2035 (Figure 5).

Figure 4: Marcellus/Utica Shale Supply Region and New England

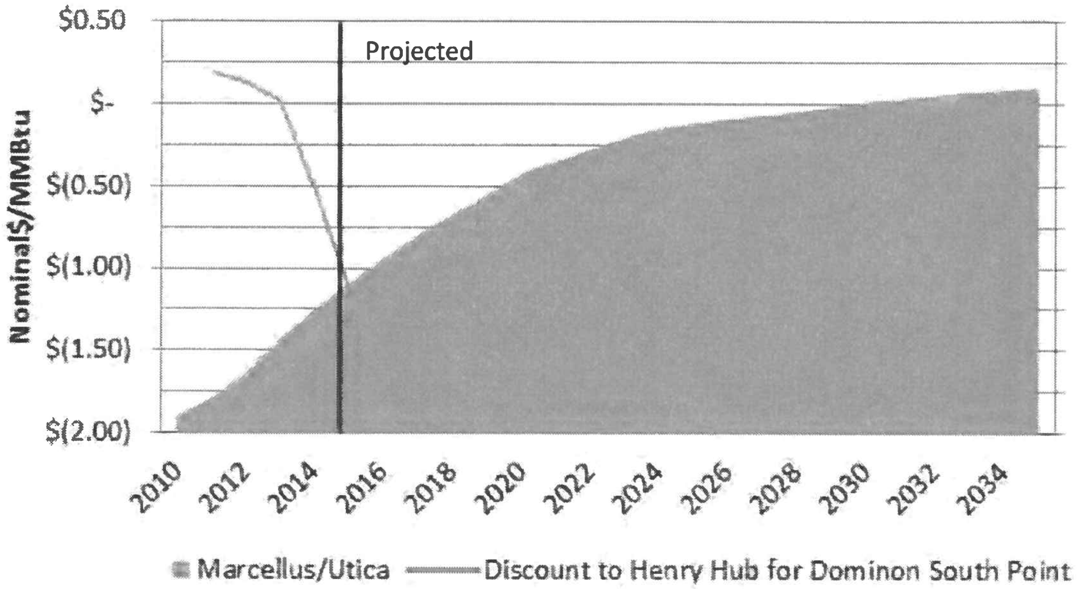


Source: ICF, Ventyx

The dramatic increase in low-cost Appalachian Basin gas production has materially altered the relationship of gas prices there to other trading points across the North American market. As shown on the left axis of Figure 5, the price of natural gas in the Appalachian Basin (represented by the Dominion South Point pricing point in Southwest Pennsylvania) is expected to be traded at significant discount relative to the North American benchmark Henry Hub (Louisiana) price.

[25] http://www.nescoe.com/uploads/6_State_Joint_Statement_FINAL_4-22-15_12-3.36pm_w-sealsf.pdf

Figure 5: Historical and Projected Marcellus/Utica Production and Dominion South Point to Henry Hub Basis[26]



Source: ICF, SNL

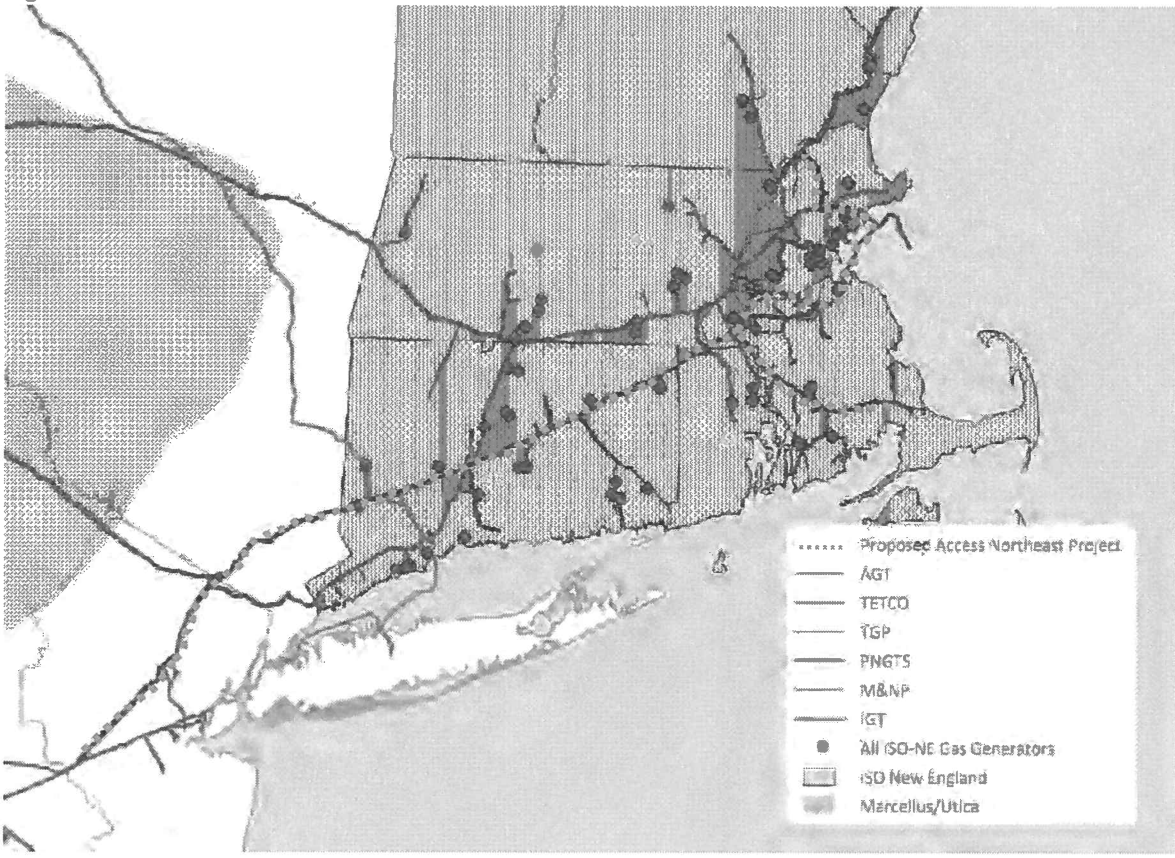
Project Description

In response to the emerging need for new firm gas services in New England, Spectra Energy and Eversource have proposed the Access Northeast project to provide scalable deliverability to Power Plant Aggregation Areas (PPAA) to directly serve power plants in order to reach the most efficient power plants on Spectra Energy's Algonquin and Maritimes pipelines. According to the proposal, Access Northeast will provide new Electric Reliability Services (ERS) for firm transportation of natural gas and natural gas supply supported by regional storage facilities for their customers. This proposed service provides greater fuel certainty and performance flexibility for generators through reserved No Notice Transportation with an hourly supply option[27]. For its analysis, ICF has assumed that the project will add 500 MMcf/d pipeline capacity and 6 Bcf of peak LNG supply through storage facilities with a maximum deliverability of 400 MMcf/d, in November 2018. While our modeling has assumed that the full capacity is available in November 2018, it is likely that the proposed project will enter into the market between 2018 and 2021.

[26] Basis presented here is TGP Z4- Line 300 price minus Henry Hub price.

[27] http://www.spectraenergy.com/content/documents/Projects/NewEngland/Access-Northeast-Project-Brochure.pdf

Figure 6: Access Northeast Overview



Source: ICF, Ventyx

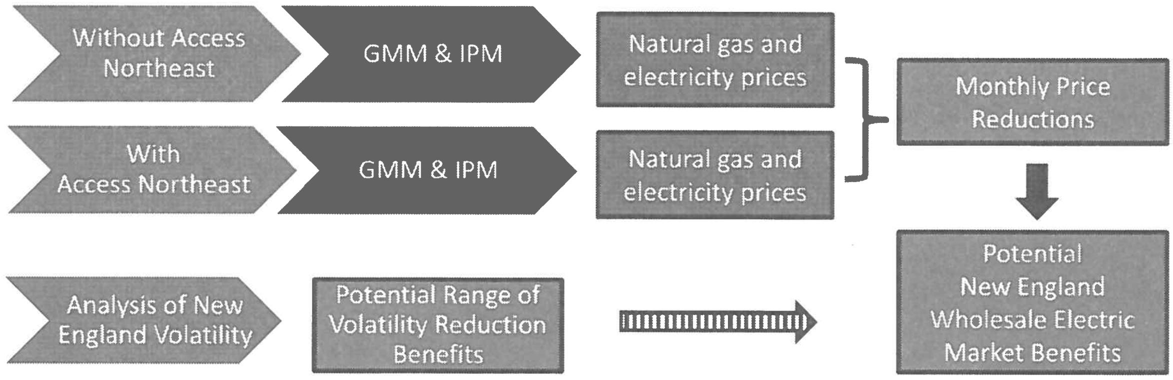
Analytical Approach

ICF's analyses and findings draw from years of experience consulting on North American natural gas and electric markets, as well as the proprietary software tools and databases developed for that purpose. For this analysis, ICF utilized a suite of analytical tools, including its Gas Market Modeling (GMM©) and Integrated Planning Model (IPM®). Descriptions of the models are provided as appendices at the end of this report.

ICF estimates Access Northeast's impacts on New England's electric market by assessing the reduction of wholesale electricity costs – measured as the wholesale energy price multiplied by total energy load in New England. The cost savings are estimated from two perspectives. For the first perspective, ICF examines the reduction of the region's average monthly natural gas and electric prices caused by the additional pipeline capacity from Access Northeast. ICF estimates this impact by running the GMM and IPM models under normal weather conditions with and without Access Northeast, and compares the difference of natural gas and electricity prices between the two scenarios. The price reduction is used to calculate the market impact and potential reduction to New England's wholesale electric costs.

In the second perspective, ICF examines Access Northeast's potential impact on natural gas price volatility by reducing the region's natural gas price spikes, which will result in subsequent reduction in the electric price spikes and provide additional cost savings. This impact is estimated as a potential range using parameters derived from historical data analysis, assuming that the incremental Access Northeast capacity would facilitate a shift in New England's natural gas market environment – either from high to medium or from medium to low volatility regimes. This analytical process is summarized below in Figure 7.

Figure 7: Cost Savings Analysis Methodology



Source: ICF

For the purpose of this analysis, ICF further assumes that reductions or increases in wholesale electric costs would ultimately flow through to all New England electric consumers.

New England Energy Market Fundamentals

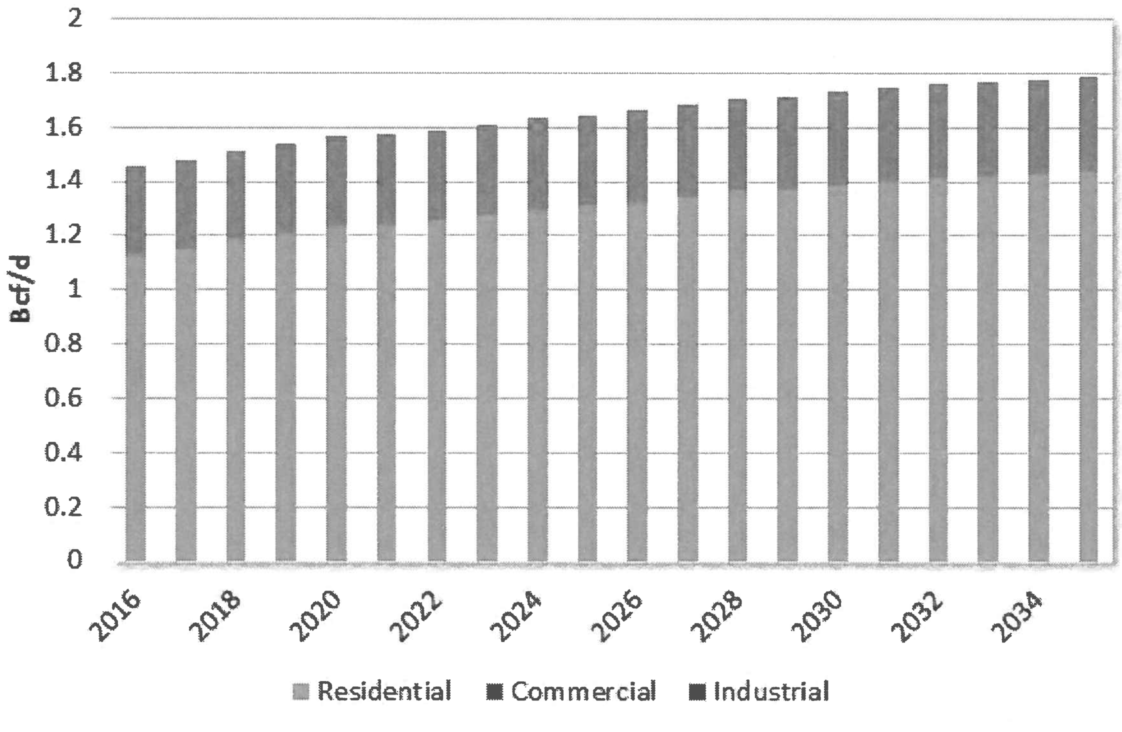
For this analysis, ICF revised its October 2015 Base Case to reflect Eversource's assumptions regarding New England natural gas and electric market fundamental development trends through 2035.

Residential/Commercial Demand

For this analysis, ICF projects New England residential and commercial natural gas demand to grow at a compound annual growth rate (CAGR) of 1.3%, between 2016 and 2035. ICF bases its near-term growth projection on the Integrated Resource Planning (IRP) filings by the 8 largest local distribution companies (LDCs) in New England, by volume of gas delivered.[28]

Through 2018, ICF assumes New England residential and commercial demand will grow at 1.9% and 3.2% over the next two years respectively, based on the LDCs IRP filings. Post-2018, ICF assumed normal weather and projects residential, commercial, and industrial gas demand growth based on a combination of factors, including projected population growth, projected economic growth, the rate of new gas customers additions, and changes in per-household gas consumption. Figure 8 below illustrates ICF's Residential, Commercial, and Industrial demand growth through 2035.

Figure 8: New England Natural Gas Demand by Sector, Normal Weather, Average Annual Bcf/d



Source: ICF

[28] Collectively, these top eight LDCs account for nearly 90% of New England's Residential and Commercial gas consumption; the top eight LDCs include National Grid (MA), Connecticut Nat. Gas Corp (CT), Southern Conn. Gas Co. (CT), Columbia Gas of Mass. (MA), NSTAR Gas Company (MA), Yankee Gas Service Co. (CT), Narragansett Gas Co. (RI), and Liberty Utilities – Energy North (NH).

Industrial Demand

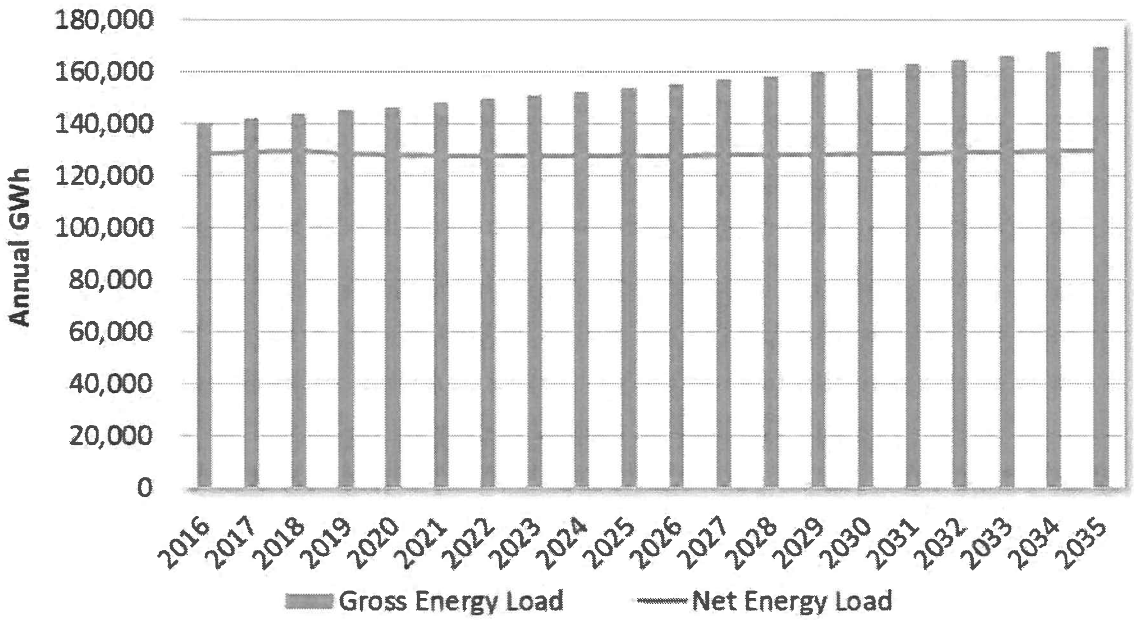
The industrial sector accounts for a relatively small share of New England's total gas demand, and ICF projects very little growth in this sector. As shown in Figure 8 above, annual average industrial demand is projected to be nearly flat at approximately 0.33 Bcf/d throughout the projection, as there are no major new industrial facilities planned in New England.

Gas Demand for the Electric Sector

Electric Load Growth

ICF employed ISO-NE's gross load forecast from 2016 to 2024 growing at the 2022 to 2024 annual average growth rate beyond 2024. Using this forecast, New England's gross electric load is expected to grow at a compound annual growth rate of 1% between 2016 and 2035. However, the assumed growth in energy efficiency and other passive demand resources offsets most of the growth, such that net energy for load grows at an average of 0.04% through 2035 (Figure 9). ICF believes that this projection reflects a relatively conservative assumption regarding New England's net electric load growth, as the Passive Demand Resources (PDR) are assumed to continuously grow at a very rigorous rate, which may not be sustainable in the long-term.

Figure 9: Gross and Net Energy Electric Load Forecast for New England



Source: ICF, ISO-NE

Capacity Retirements and Builds

In this analysis, ICF assumes that approximately 4,150 MW of coal, oil/gas and nuclear generation capacity in ISO–NE is retired by 2019 as shown in Table 2; this includes almost 1,760 MW of capacity already retired by the end of 2014.

Table 2: ISO – New England Firm Retirements[29]

Plant Name	Owner	Capacity Type	State	Year	MW
Lowell Cogeneration Plant	Alliance Energy NY	Gas	MA	2013	28
Norwalk Harbor 1-3	Norwalk Power LLC	Oil/Gas	CT	2013	342
Cabot Holyoke: 6	Holyoke City of MA	Oil/Gas	MA	2013	10
Cabot Holyoke: 8	Holyoke City of MA	Oil/Gas	MA	2013	10
Salem Harbor 4	Dominion	Oil/Gas	MA	2014	437
Bridgeport Harbor 2	PSEG	Oil	CT	2014	182
Salem Harbor 3	Footprint Power	Coal	MA	2014	150
Vermont Yankee 1	Entergy	Nuclear	VT	2014	604
Mt. Tom	GDF Suez	Coal	MA	2015	144
Kendall Steam	GenOn	Gas	MA	2016	25
Brayton Point 1-4 and Peaking	ECP	Coal/Oil/Gas	MA	2017	1535
Pilgrim	Entergy	Nuclear	MA	2019	685
Total					**4151**

Source: ICF

Based on announced capacity additions, ICF assumes about 1,740 MW of firm natural gas generation capacity (capacity that cleared the forward capacity auctions) will be added in ISO – NE by 2019 (Table 3).

Table 3: ISO – New England's Firm Capacity Additions by 2019 (MW)

Fuel	2015	2016	2017	2018	Total
Biomass			7		**7**
Solar[30]		4	1	16	**21**
Wind	64	7	6		**77**
Water	2	48			**50**
Landfill Gas			1	1	**2**
Oil/Gas		39			**39**
Natural Gas	10		690	1043	**1743**
Total	**76**	**98**	**704**	**1060**	**1938**

Source: ICF

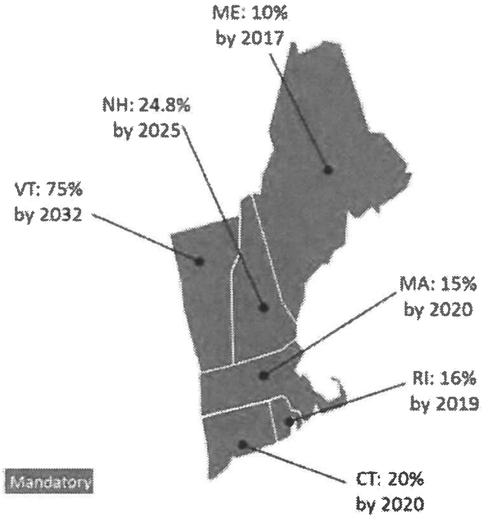
[29] Retirements considered firm if they are permanently delisted units or if they have submitted a non-price retirement request that ISO-NE has accepted.

[30] Solar does not include "behind the meter" residential and commercial solar installations, which are not included in the ISO-NE queue. The 2015 ISO-NE CELT Forecast assumptions used in the modeling are net of these "behind-the-meter" solar installations.

Renewables

ICF assumes that all New England states' Renewable Portfolio Standards ("RPS") are met according to currently proposed timelines. Each state's respective RPS goals can be seen below in Figure 10.

Figure 10: New England State RPS Standards



Source: ICF, state's RPS

Environmental Regulations

For this analysis, ICF assumes that federal maximum achievable control technology (MACT) standards, consistent with those set by the Environmental Protection Agency (EPA) in its final mercury and air toxics standards (MATS) released on December 21, 2011, will be in effect throughout the projection. ICF also assumes that the EPA will not have an alternative to the current Clean Air Interstate Rule (CAIR) regulations, and that the current CAIR remains in place through 2017. In 2018, ICF-assumed standards tighten to the Cross State Air Pollution Rule (CSAPR) Phase II requirements.

Clean Power Plan (CPP)

ICF incorporated the regulatory impacts of EPA's Clean Power Plan (CPP), recently finalized on August 2015 for this analysis. While the EPA's final rule has been issued, there is still considerable uncertainty about future CO_2 control policy, because the CPP allows for multiple paths to comply. Additional, several states have filed legal challenges to the CPP Rule. To represent continued uncertainty over the future implementation of carbon policy, ICF has used its Integrated Planning Model (IPM) to assess the impact of three policy cases:

- No CO2 Policy Case, which is considered increasingly unlikely after 2020;
- Middle Case, based on mass caps over existing fossil units as outlined in the CPP Final Rule;
- High Case, assuming implementation of a more stringent, multi-sector emission control policy.

Results from these three cases have been used to create probability-weighted CO_2 allowance prices in the power sector, which in turn drive electric capacity retirements, new builds, and dispatch decisions that are reflected in ICF's projected gas demand and prices.

Projected Supply Sources into New England

New England's primary source of natural gas supply is now Marcellus/Utica production, which is then transported to New England's LDCs principally via TGP and AGT. During peak winter months New England also relies on both peak shaving facilities operated by LDCs as well as intermittent LNG imports via LNG import terminals. Canadian production from Nova Scotia and transported on M&NP has dwindled in recent years and no longer serves as a primary source of natural gas supplies to New England during peak winter months.

LNG Imports

New England has one onshore LNG import facility, Distrigas's Everett LNG terminal. Between 2010 and 2014, total volumes delivered out of Everett declined by 81%. In response to cold weather and higher prices, volumes rebounded slightly in January 2015, but the 2014/15 peak winter sendout was still less than half of the 2011 volumes. ICF projects annual average and peak winter sendout from Everett to be similar to the 2014-2015 winter levels, declining slightly after new pipeline capacity (AIM, TGP CT, and Atlantic Bridge) is added. This assumption remains unchanged for all of analysis provided herein.

New England also has two offshore LNG import terminals: Neptune and Northeast Gateway. Neptune has not received shipments since 2010, and in 2013 suspended its deep-water port license. Northeast Gateway received two shipments in January 2015, its first since 2010. ICF projects that neither Neptune nor Northeast Gateway are likely to provide gas supplies to New England in the future.

Canadian Supplies via M&NP

M&NP has nominal capacity to deliver up to 0.8 Bcf/d into New England. M&NP was originally designed to bring production from Sable Island Offshore Energy Project (SOEP) to markets in the Maritimes Provinces and New England. M&NP also receives production from the Deep Panuke offshore field and a small onshore field (McCully).

Weaker-than-expected production from SOEP left M&NP underutilized. In 2008, Repsol commissioned Canaport LNG in New Brunswick, which has provided additional supplies for M&NP. In 2013, Repsol sold its LNG supply contracts and ship charters to Shell, leaving Canaport with only a small fixed supply contract.

Even as Eastern Canadian production and LNG imports have declined[31], gas demand in the Maritimes provinces has been increasing. While relatively small, at about 0.2 Bcf/d, demand in the Maritimes provinces uses supplies that could otherwise be exported to New England. Flows on the M&NP system have already reversed on occasion, with gas flowing north into New Brunswick. Even if Canaport continues

[31] On Jun 25, 2015, CBC News reported that ExxonMobil Decommissioning manager Friederich Krispin said that "the work [decommissioning SOEP] will begin as early as 2017 when the company hires a rig to plug and abandon wells."

to import at or slightly above recent levels, the Maritime Provinces are likely to be net gas importers by 2020. As such, M&NP is unlikely to provide gas supplies during the winter peak starting in 2020.

Firm Pipeline and Supply Capacity into New England

TGP, AGT, PNGTS, and IGT have existing firm contracts into New England that total about 3.1 Bcf/d. Three planned pipeline expansions (AGT AIM and Atlantic Bridge, and TGP Connecticut) will provide about 0.6 Bcf/d of additional gas supplies into New England on peak winter days. Based on sendout over the past two winters, Everett is expected to provide no more than 0.25 Bcf/d during peak winter periods. M&NP is still expected to provide some winter supplies in the next few years, but then drop to zero due to decreasing supplies and increasing demand in the Maritime Provinces. This leaves New England with winter gas supplies of about 4 Bcf/d by 2020, as shown in Table 4.

Table 4: Assumed Winter Capacity from Existing Pipelines, Planned Expansions, and LNG Supplies to New England (Bcf/d)[1]

	Supply Path	2020 - 2035
Expected Supplies from Existing Pipelines and LNG Imports	TGP	1.41
	AGT	1.35
	IGT[2]	0.21
	PNGTS[3]	0.17
	M&NP[4]	0
	Everett LNG	0.25
Supplies from Pipeline Expansions	AIM	0.34
	TGP - Connecticut Expansion	0.07
	Atlantic Bridge	0.13
	Total Pipeline and LNG Supplies	**3.95**

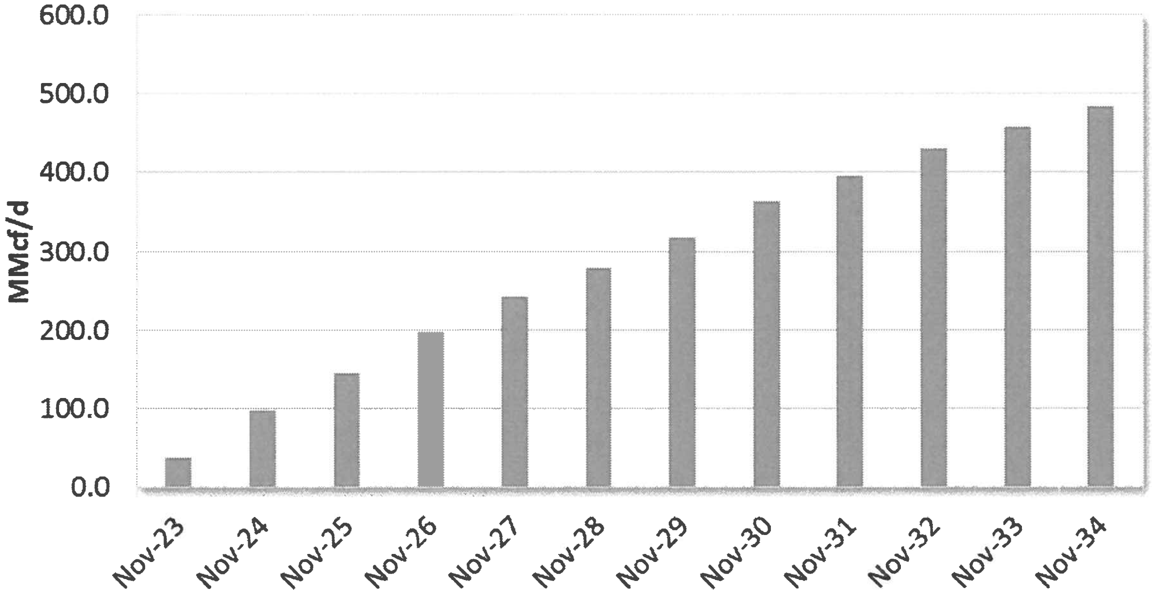
Source: ICF

1. Unless noted, the table reflects operational capacity. Historical data shows that physical flows occasionally exceed operational capacity under certain conditions.
2. IGT capacity is estimated using firm contracts with receipt points outside of New England and delivery points to end customers in New England according to second quarter 2015 IGT Index of Customers.
3. PNGTS operational receipt capacity at Pittsburg.
4. Due to declining production in offshore Nova Scotia, no firm supply from Eastern Canada is expected into New England during the winter months by 2020.

LDC Incremental Expansions

The energy demand/supply trends described above indicates that New England faces the risk of persistent and growing natural gas supply constraints, absent new sources of capacity. Given the current structure of the regional energy markets, such risks could disproportionately affect electricity markets, raising economic and potential service reliability concerns for consumers across the region. Access Northeast is proposed to help address the electric market's needs for incremental infrastructure. In order to isolate Access Northeast's impact on the natural gas and electric market, ICF assumes that the LDC needs for incremental capacity is immediately met with continuous expansions so than total January residential, commercial and industrial demand amounts to 75% of total firm capacity into New England. The expansions are assumed to be on-line in November of each year. As shown in Figure 11, LDC load will require additional expansions to start in 2023 and cumulatively reach approximately 500 MMcf/d by 2035.

Figure 11 – Cumulative Capacity Expansion for LDCs Load Requirements



Source: ICF

Electric Consumer Cost Savings - Normal Weather

ICF has estimated the energy market impact of Access Northeast by running GMM and IPM models under normal weather conditions with and without the project, and has then compared the difference for natural gas prices and wholesale power prices. The wholesale power price reduction was then used to calculate the market impact and potential cost savings to New England electric consumers. In addition, the project's impact on natural gas price volatility and the resulting further reduction to electric price spikes were then estimated separately utilizing a statistical approach.

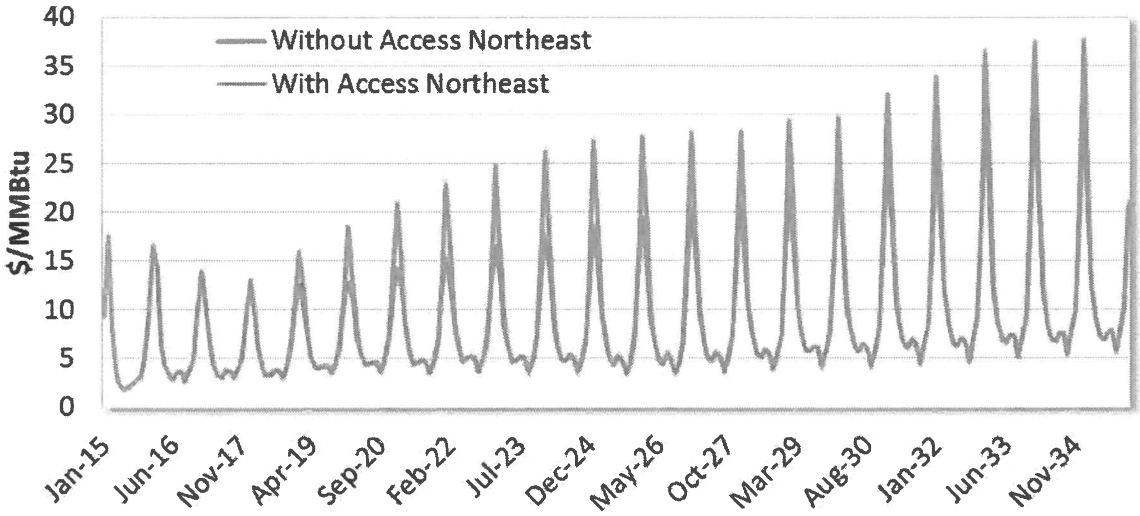
Natural Gas Price Impact – Monthly Average

Figure 12 shows that without Access Northeast, under normal weather conditions, ICF projects that peak winter month gas prices in New England will initially decline from the levels seen in the past two winters. Incremental capacity expansions (such as AIM, Tennessee's Connecticut Expansion, and Spectra's Atlantic Bridge) will temporarily contain the peak winter price for three years before demand growth and Eastern Canada supply declines outpace the expanded capacity. Peak winter prices then will steadily increase over time and exceed, in 2024, the levels experienced in the Polar Vortex winter of 2013/14 and surpass a monthly average of $30/MMBtu by 2030.

In this projection, Access Northeast significantly lowers peak winter gas prices. Even though prices continue to rise as the market responds to demand growth and supply declines, peak winter monthly prices are projected to be substantially lower than levels reached in the 2013/14 winter. During the peak winter months of December, January and February, Access Northeast would reduce prices by as much as $8.60/MMBtu. On an annual average basis, Access Northeast reduces New England's natural gas prices by $1.30/MMBtu over the 17-year period between 2019 and 2035. While this difference is below the unit cost of the pipeline, suggesting that Access Northeast's benefit is less than its cost, the actual benefit from the pipeline as measured with electric price change for all electric consumers is much greater than the cost of the pipeline (as shown in the section that directly follows).[32] Further, this measure does not include the additional benefit that results from reductions in daily price volatility that are also discussed below.

[32] The reduction impact in New England's natural gas price will be amplified dramatically on the power market, as every unit of electricity consumed in New England will be priced lower when the natural gas fired generation units determine the wholesale power prices.

Figure 12: New England Natural Gas Price Forecast – Monthly Average

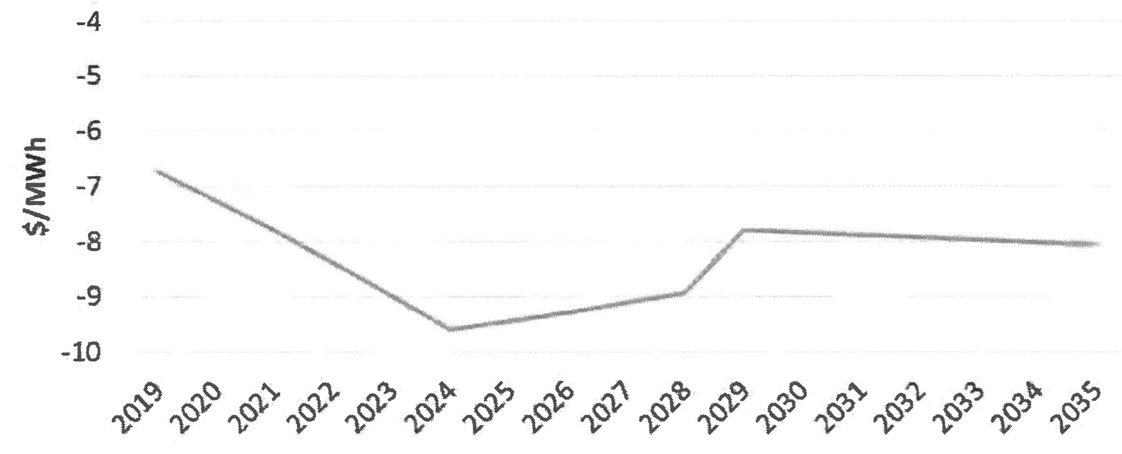


Source: ICF, SNL

Wholesale Power Price Impact – Monthly Average

New England's wholesale power prices are closely related to natural gas prices due to the region's dependence upon gas-fired power generation capacity. By reducing spot prices in New England, the Access Northeast market project would have a direct impact on New England's wholesale power prices. As shown in Figure 13, Access Northeast reduces the New England annual average wholesale power price by $6/MWh to $10/MWh between 2019 and 2035.

Figure 13: New England Annual Average Wholesale Power Price Reductions with Access Northeast

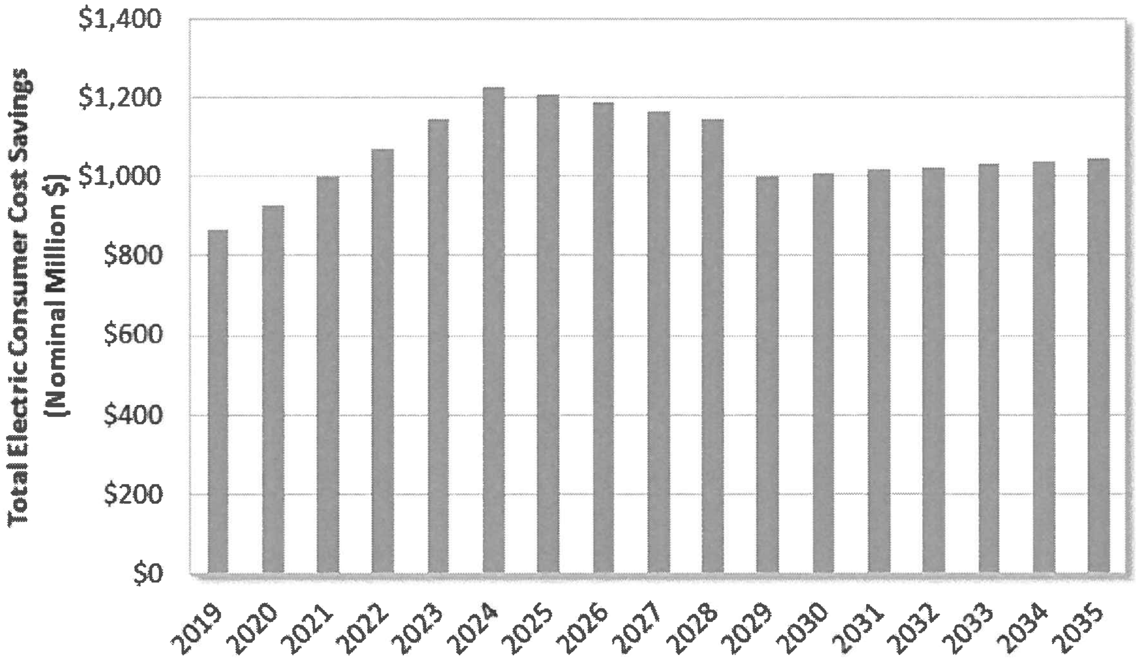


Source: ICF

Cost Savings from Average Price Reductions

The analysis results presented above show that Access Northeast would reduce New England's wholesale electricity prices by lowering the regional natural gas price and the fuel costs for gas-fired power generation. In this analysis, ICF assumes that wholesale power price reduction provided by infrastructure solutions reduces the wholesale costs across New England. Annual wholesale power cost savings are calculated as the reduction in New England's wholesale energy prices multiplied by ISO-NE annual net energy load. ICF estimates that Access Northeast would potentially generate annual cost savings of $860 million to $1.2 billion[33] for the 17-year period between 2019 and 2035, averaging $1.1 billion, as shown in Figure 14.

Figure 14 – Annual Energy Cost Savings from Monthly Average Electricity Price Reduction



Source: ICF

Benefits from Reduced Daily Gas Price Volatility

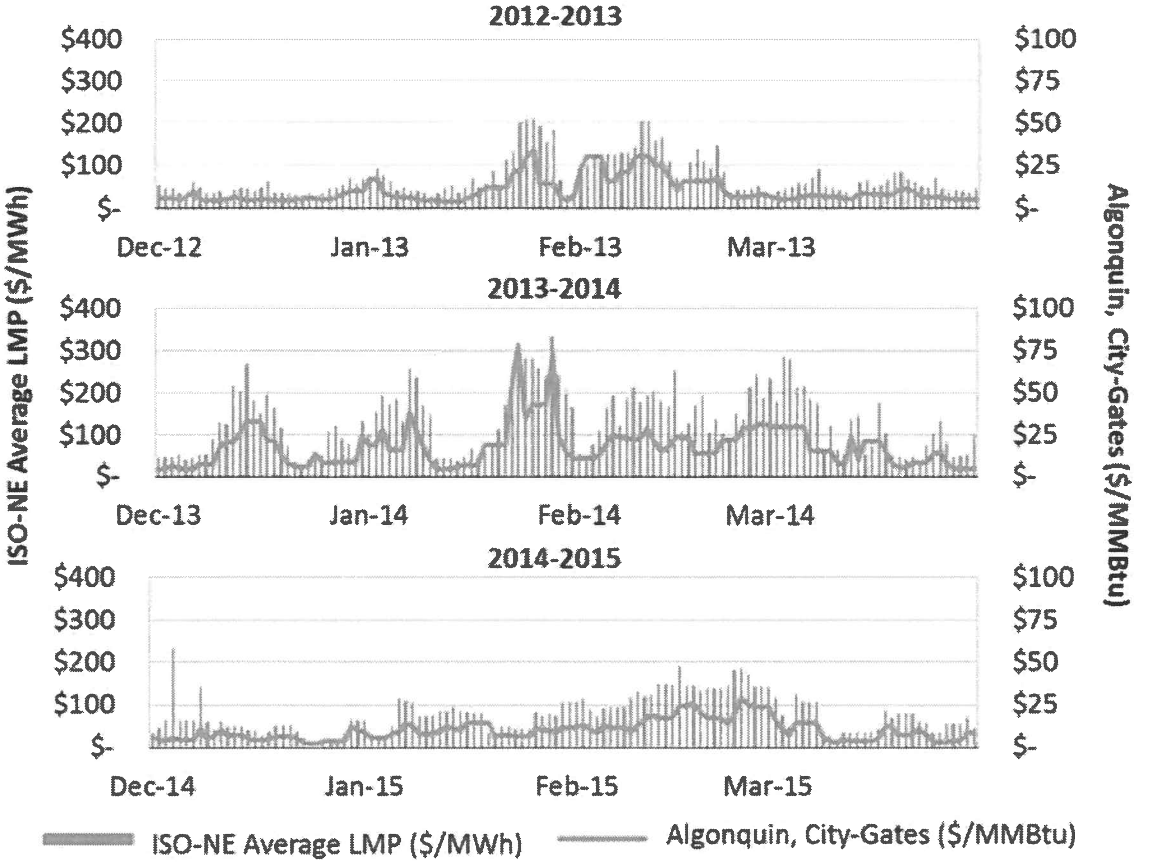
In addition to the monthly average price reduction that ICF has estimated using the GMM and IPM models, the gas supply capacity created by a project like Access Northeast would produce additional cost savings through reductions in daily natural gas and power price volatility. New England's gas and wholesale power prices both exhibit asymmetric patterns – daily prices can spike up to extremely high levels, but only decline modestly. Therefore, reduction in the frequency and magnitude of natural gas and electricity price spikes would potentially result in price reductions beyond the monthly average levels discussed above. ICF estimated the potential impact of volatility only for the peak winter months of December through March.

Price volatility is determined by complex market drivers, the analysis of which is beyond the scope of this report. For this study, ICF assumed certain ranges of reduction of frequency and magnitude of extraordinary price spikes as a proxy to measure the impact of volatility reductions. Figure 15 presents

[33] The cost savings discussed throughout this report do not include potential revenues from capacity released into the market.

daily Algonquin City Gate gas prices and ISO-NE daily average real-time locational marginal prices (RTLMPs—prices for electricity at different locations in the grid) for the past four winters.

Figure 15 - New England Historical Gas and Electric Price Volatility



Source: ICF, SNL, ISO-NE

As discussed previously, future fundamental natural gas market development trends in New England, including increases in natural gas demand and diminishing supply sources from Canada and LNG imports, would increasingly stress the natural gas infrastructure serving New England and create significant constraints during peak winter months and highly volatile prices even under normal weather conditions, similar to the volatilities observed under extreme weather conditions in North American for the polar vortex winter of 2013/2014. Therefore, without incremental capacity such as Access Northeast, New England natural gas price would become increasingly volatile even under normal weather conditions.

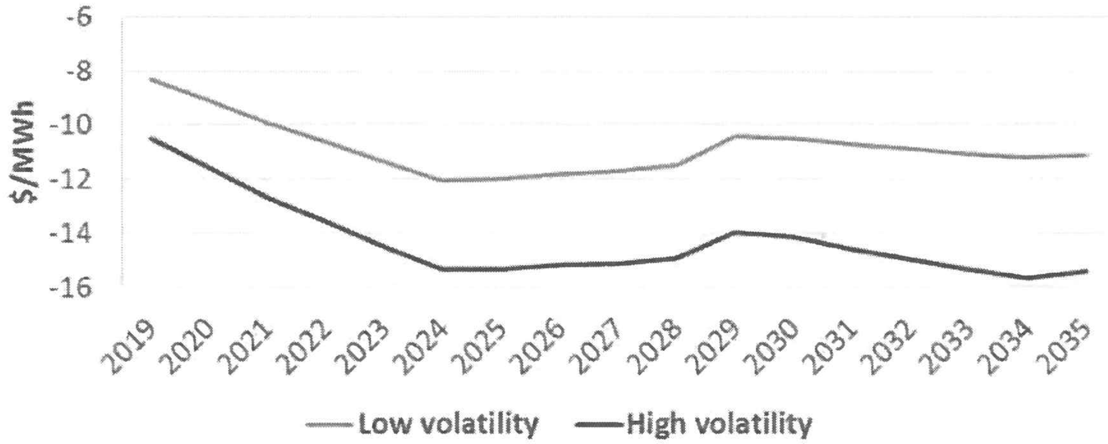
The range of Access Northeast's potential volatility reduction impacts is estimated assuming two volatility reduction levels:

- Low Volatility Reduction Assumption - Frequency and size of price spikes are reduced by approximately half from a moderate volatility market, similar to what was experienced in the 2012/2013 or 2014/2015 winter;

- High Volatility Reduction Assumption - Frequency and size of price spikes are reduced by approximately half from a high volatility market, similar to what was experienced in the 2013/14 winter.

These assumptions result in greater wholesale power price reductions as shown in Figure 16, which in turn generate additional cost savings of $0.33 billion to $0.77 billion per year on average over the 17-year period of 2019 through 2035.

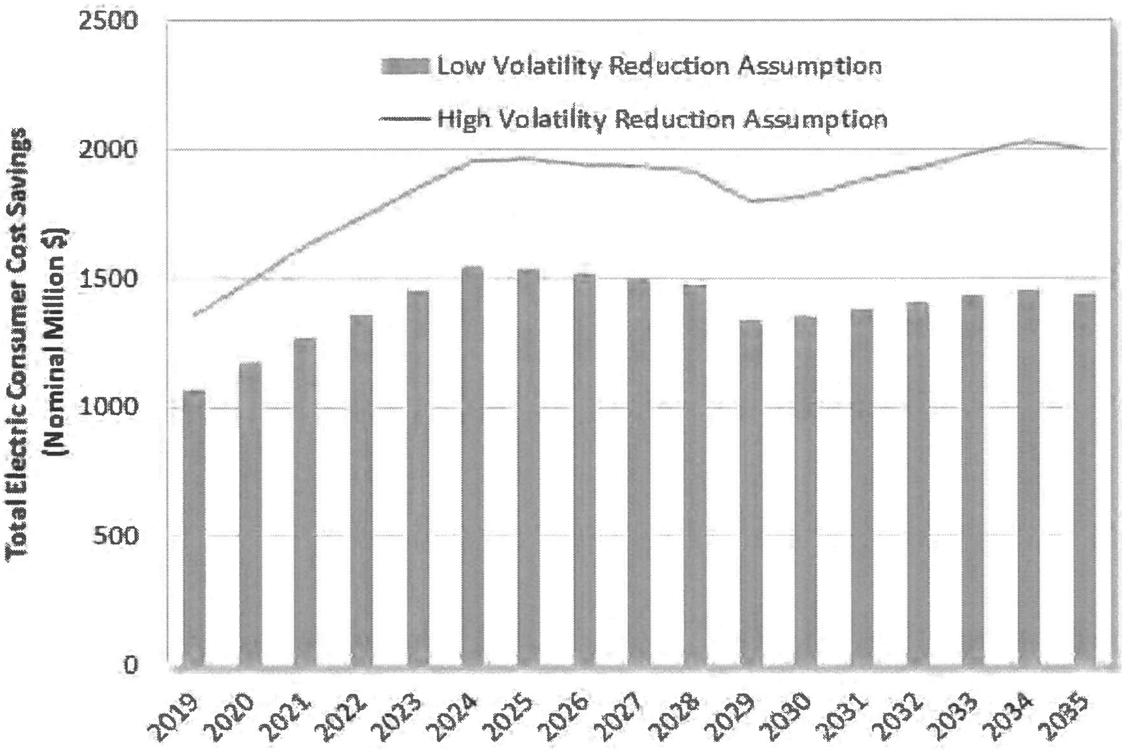
Figure 16: New England Annual Average Wholesale Power Price Reductions with Access Northeast



Total Estimated Impact to Consumers

With Access Northeast reducing prices of natural gas and thus reducing the price of wholesale power for New England consumers, Figure 17 shows that the savings from Access Northeast varies over time from about would generate $1.1 billion to $2.0 billion per year to New England electric consumers, depending on volatility conditions. The annual average cost savings to consumers due to the lowered electricity prices alone for the 17-year period is $1.1 billion, and adding the benefits of volatility reductions results in $1.4 billion to $1.9 billion for the low and high volatility assumption scenarios, respectively.

Figure 17 - New England Electric Consumer Cost Savings, including volatility



Source: ICF

Total Estimated Impact to Consumers by State

The consumer benefits accrue to the different New England states differently, depending on the net load and the electricity price savings in each of the states; see Table 5. Consumers in Massachusetts, Connecticut, and New Hampshire are the states will benefit the most from the Access Northeast project, because these states have the largest percentage of load. The benefits in these three states account for 80% of the total ISO-NE benefits, with Massachusetts consumers accounting for about 44% of the benefits.

Table 5: State-wise Electric Consumer Average Annual Savings (in nominal million dollars) 2019 to 2035 Under Different Volatility Assumptions

States	Load (TWh)	No Volatility	Low Volatility	High Volatility	% of Savings
Massachusetts	58.1	$480	$630	$830	45%
Connecticut	32.5	$290	$370	$480	26%
New Hampshire	12.8	$110	$140	$185	10%
New England ISO	128.4	$1,090	$1,410	$1,850	100%

Source: ICF

Note: State-wise benefits were computed from ISO-NE RSP Subarea model results based on the RSP Subarea to State allocation specified in Table 3-4 of the 2014 ISO-NE Regional System Plan.

Electric Consumer Cost Savings - Cold Weather and Nuclear Outage Scenario

ICF assessed the impact of Access Northeast by assuming that the winter of 2021-2022 is a "1-in-20 year design" winter, and simultaneously experiences a large nuclear outage event. For the electric market, ICF also used the 90-10[34] scenario from ISO-NE's CELT report that has a significantly higher peak energy load profile than under the normal weather conditions.

Weather and RCI Demand Assumptions

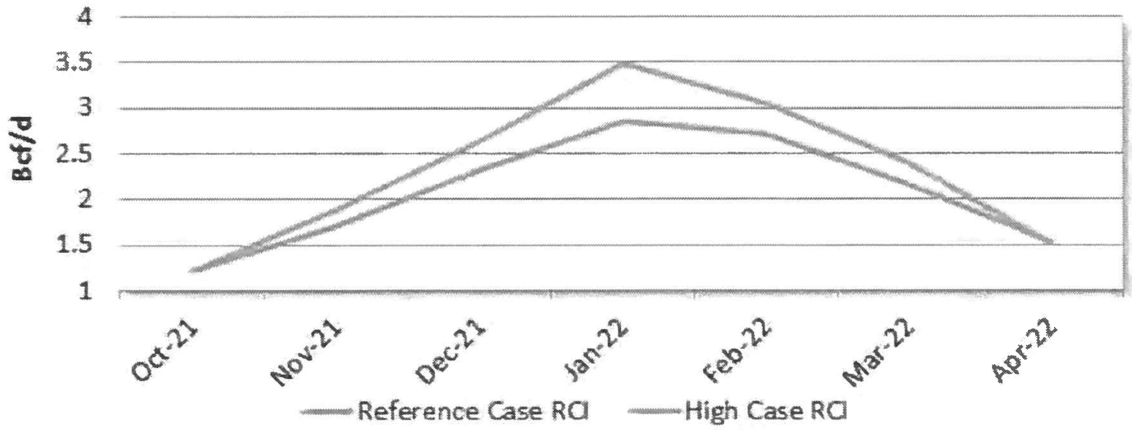
ICF utilized the design winter weather data provided by Eversource, to calibrate the design winter conditions in New England. Table 6 shows that the design winter is, on average, 17 percent colder than normal winter conditions. Figure 18 shows that residential, commercial, and industrial demand for the five winter months is 14 percent higher than under normal weather conditions.

Table 6: Weather Assumptions

	Normal HDDs	1-20 Design HDDs	Design Winter Colder %
November	708	812	15%
December	1036	1188	15%
January	1222	1522	25%
February	1052	1207	15%
March	916	1051	15%

Source: Eversource, ICF

Figure 18 - RCI Demand Comparison - High Winter Case vs. Reference Winter Case



Source: ICF

[34] The 90/10 scenario refers to ISO-NE's electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 10%. Therefore, a high electric load demand is estimated.

Price Impact and Cost Savings

Under the cold weather and nuclear outage scenario, Access Northeast is expected to have a more significant impact on natural gas and electric markets. Table 7 shows that on average (before taking volatility into consideration), natural gas prices would be reduced by about $15/MMBtu during peak winter month, and electric prices would be reduced by nearly $80/MWh.

Table 7: Colder than Normal Winter Scenario Power and Gas Price Results in New England

	Gas Price Savings ($/MMBtu)	Electricity Price Savings ($/MWh)	Consumer Savings ($ million, nominal)
Nov 2021	$1.9	$7	$90
Dec 2021	$10.2	$40	$590
Jan 2022	$14.9	$80	$1,120
Feb 2022	$9.4	$45	$610
Mar 2022	$2.8	$13	$190
2021-22 Winter	**$7.8 (Avg.)**	**$37 (Avg.)**	**$2,600 (Total)**

Source: ICF

Access Northeast would generate approximately $2.6 billion cost savings to electric consumers in the five winter month period, and about $3.1 billion of costs savings on an annualized basis.[35] The total annualized consumer savings (2021-22) by state under the cold weather and nuclear outage scenario is shown in Table 8.

Table 8: State-wise Annualized Savings under Colder than Normal Winter and Nuclear Outage Scenario

	Annualized Consumer Savings ($ million, nominal)
Massachusetts	$1,390
Connecticut	$780
New Hampshire	$270
ISO-NE	$3,100

Source: ICF

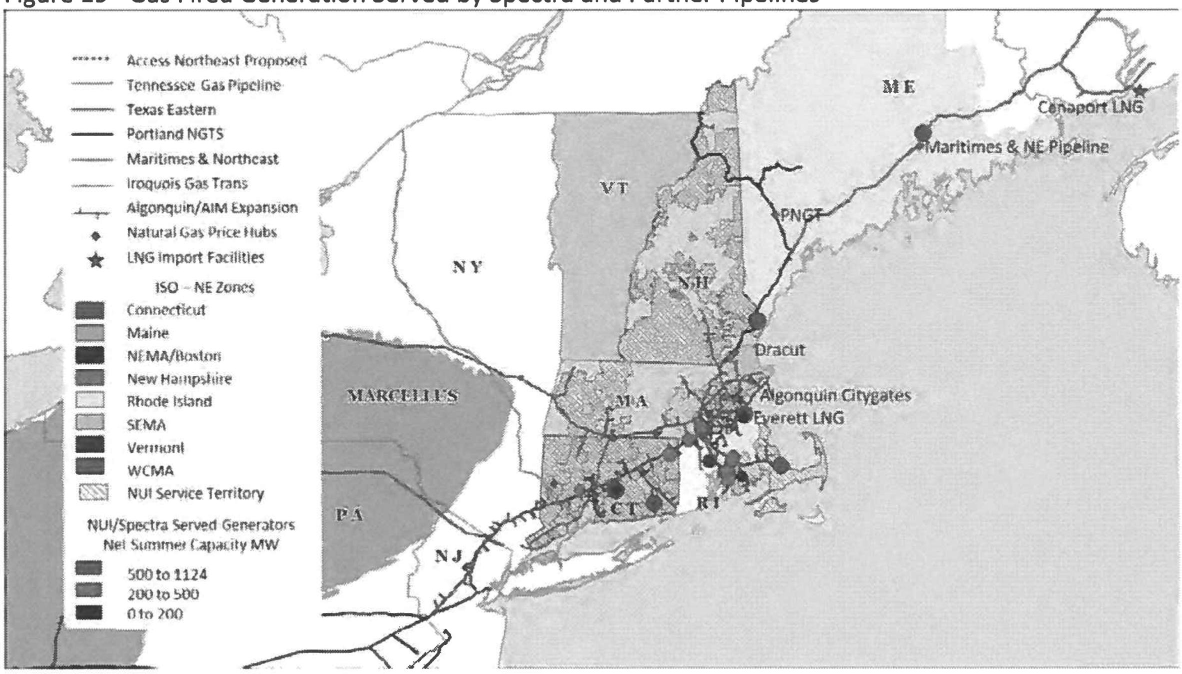
[35] Annualized savings are calculated as savings from November 2021 to October 2022.

Reliability and Other Benefits

Access Northeast would increase ISO-NE's electric system reliability by directly providing firm natural gas fuel for gas fired power generators and help New England potentially avoid costly load shedding measures under extreme circumstances.

To maintain electric system reliability and potentially prevent spikes in wholesale electricity prices, New England's gas-fired electric generators will need access to firm, reliable and economic natural gas supplies, particularly during the winter months. Access Northeast is designed to supply a significant amount of new pipeline capacity to both existing power plants and proposed facilities and will provide access to domestically sourced peaking LNG supply during winter periods. This design will optimize the use of existing natural gas infrastructure by providing year round access to more natural gas and, when demand for gas is low (typically, Spring, Summer and Fall) storing this domestic gas in regional LNG facilities to be used by electric generation during the Winter. Figure 19 shows that the proposed project can potentially serve 6,900 MW, or nearly 70 percent of the region's existing natural gas fired power generation capacity interconnected to the pipeline system and operating without backup fuel capability[36]. By providing secure fuel supplies to these generators, Access Northeast could significantly improve electric reliability across the grid.

Figure 19 - Gas Fired Generation Served by Spectra and Partner Pipelines



Source: Ventyx

The ISO-NE has developed a market enhancement that is intended to improve generation availability in order to mitigate the adverse consequences of reliability shortage events. This program is known as "Pay

[36] Including connections with ALQ, MN&P and Iroquois.

for Performance" (or Performance Incentives "PI") and is planned to be implemented by ISO-NE on June 2018. Once the program is in place, severe penalties ($2,000/MWh increasing to $5,455/MWh over time) will be levied on generation that is not available to run at its credited generation capacity level during a generation resource shortage. As ICF has pointed out, currently there could be insufficient firm fuel for as much as 5,700 MW of generation, which means that during winter shortage events the existing gas fired generation units could incur severe penalties if they are not able to dispatch.[37] The infrastructure solution provided by Access Northeast and the Electric Reliability gas supply service, is capable of providing fuel for up to 5,000 MW and can provide this fuel to follow the hourly gas load variations of power plants. Access Northeast will, therefore, help ISO-NE meet its system reliability mandate and help generation avoid the PI shortage penalties.

In addition, the value of pipeline capacity reliability for a region increases materially as gas use for power generation grows. Without adequate gas capacity, New England's electric system could face costly load shedding measures. Studies regarding the estimated costs of power service outages are limited, but a 2013 filing with state regulators by Potomac Electric Power (PEPCO), a PJM electric utility that serves Maryland and Washington D.C., provides one benchmark. In that filing, summarized in Table 9, PEPCO estimated that an eight-hour outage for a quarter of its customers could cost approximately $988 million. Access Northeast can help New England avert this type of costly electric load shedding.

Table 9: Estimated Costs of Outages by PEPCO in 2013 Maryland State Filing

Customer Class	Total Cost per Customer for an 8 hour Outage ($)	One Quarter of Total Customers	Estimated Costs for an 8 Hour Outage affecting a quarter of Total Customers ($)
Residential	11	58,774	623,004
Small Commercial and Industrial	5,195	65,453	340,027,569
Large Commercial and Industrial	69,284	9,350	647,833,633
TOTAL		**133,557**	**$988,484,206**

Source: PEPCO

New England states have ambitious goals for deployment of renewable generation. Due to the intermittent nature of wind and solar generation, additional quick response gas-fired generation is needed as renewables' share of total generation increases. Access Northeast will provide services that are designed specifically to follow the hourly gas load variations of power plants as electric load and gas fired generation dispatch fluctuates during the day. Access Northeast is also well positioned to provide fuel supplies to insure that generators have a fuel supply when renewable resources are not generating due to the intermittent and unpredictable nature of the resources.

[37] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II, page 21, Exhibit 4-6.

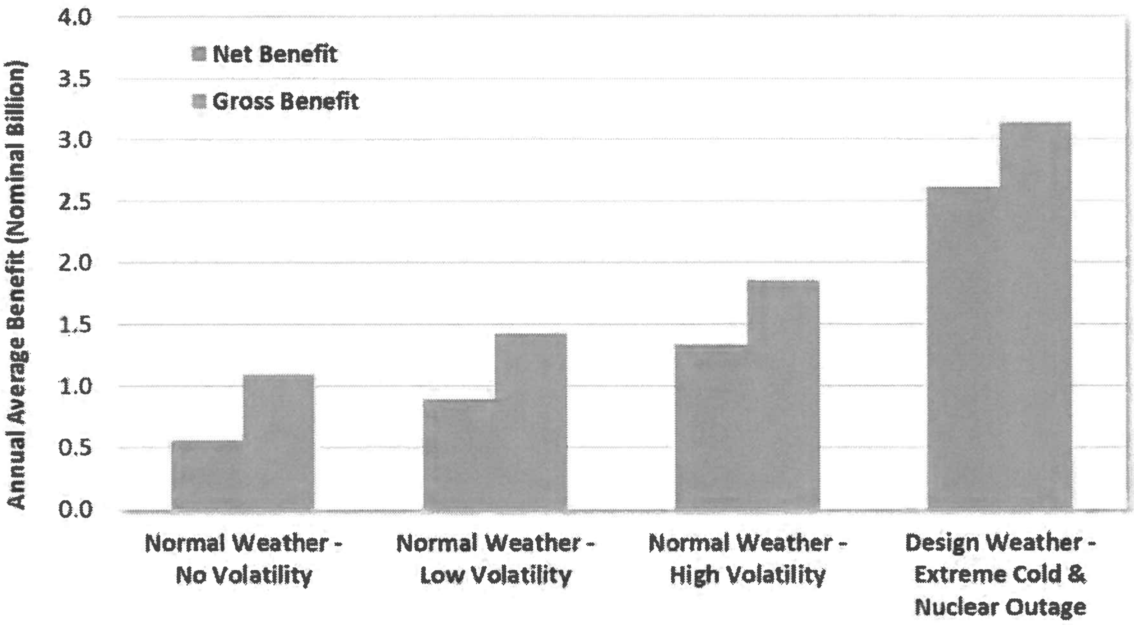
Cost / Benefits of Access Northeast

The portion of Access Northeast that will serve electric generation in New England, assumed in ICF's analysis is estimated to cost $2.4 billion. Assuming this translates into a $526 million annual cost, after taking into account the return on the capital investment and O&M costs annually to operate the capacity, the estimated benefits of Access Northeast to New England exceed its costs in all scenarios.

Table 10: Annual Access Northeast Benefits and Cost Summary (Average of 2019-2035)

	New England (Nominal Billion)	MA (Nominal Million)	CT (Nominal Million)	NH (Nominal Million)
Normal Weather (Low Volatility)	$1.4	$630	$370	$140
Normal Weather (High Volatility)	$1.9	$830	$480	$185
Design Weather (2021-2022)	$3.1	$1,390	$780	$270
Costs	$0.5	TBD	TBD	TBD
Net Benefits (Low-High Volatility)	$0.9 - $1.3	--	--	--

Figure 20: Annual Average Gross and Net Benefits for New England under Different Scenarios



Source: ICF

The net benefits to New England, ranging from $1.0 billion to $2.7 billion, assumes that New England's electric consumers bear the full cost of the electric portion of the project, so those costs are netted out of the total savings that ICF has estimated. However, the cost savings to consumers would be greater if projected revenues for pipeline reservation charges paid by electric generators were to be credited back to the consumers as is proposed. We also estimate that the majority of the $2.4 billion investment required for the project would be recovered from the cost savings in a single extreme winter (design winter), similar to the 2013/14 winter. Furthermore, consumers in Massachusetts, Connecticut, and New Hampshire stand to benefit the most from the electric savings due to Access Northeast, due to the allocation of load.

Appendix: Description of ICF Models

ICF's Gas Market Model (GMM®) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. Since then, the GMM has been used to complete strategic planning studies for governments, non-government associations, utilities, and private sector companies. The different types of studies include:

- Analyses of pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure 1). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

There are nine different components of ICF's model, as shown in Figure 2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The gas consumption for the power sector is matched with the outputs from the IPM model (described below), and the two models (GMM and IPM) are run together until the gas prices and power sector gas consumption are converged.

The GMM model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure 3. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The supply component may be integrated with the GMM to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (*i.e.*, gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (*i.e.*, end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Figure 1: Natural Gas Supply and Demand Curves in the GMM

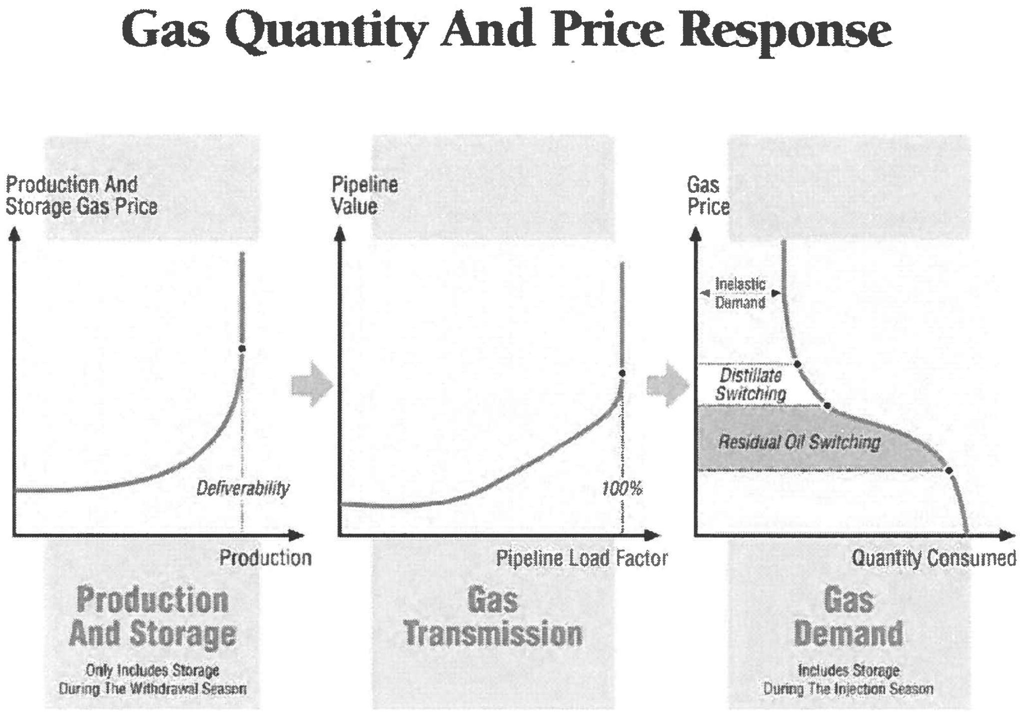


Figure 2: GMM Structure

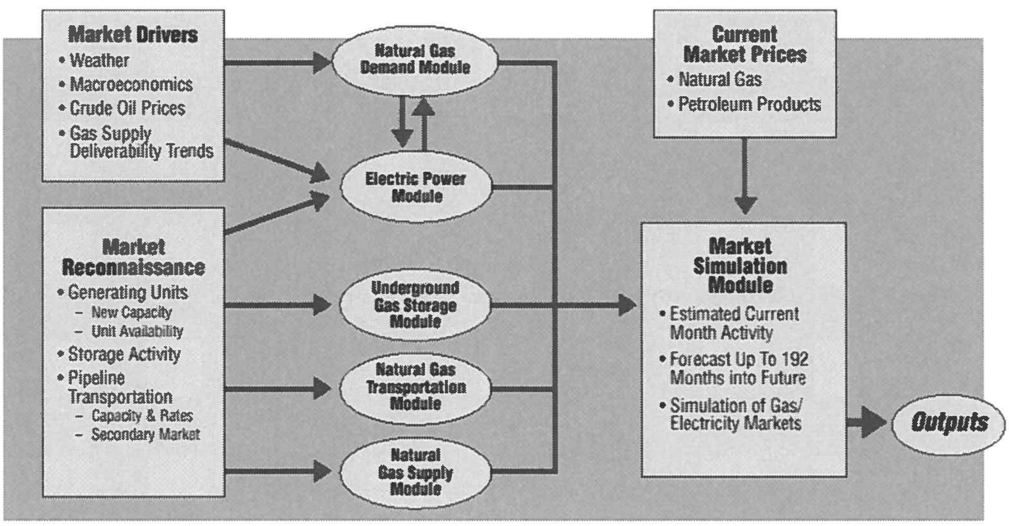
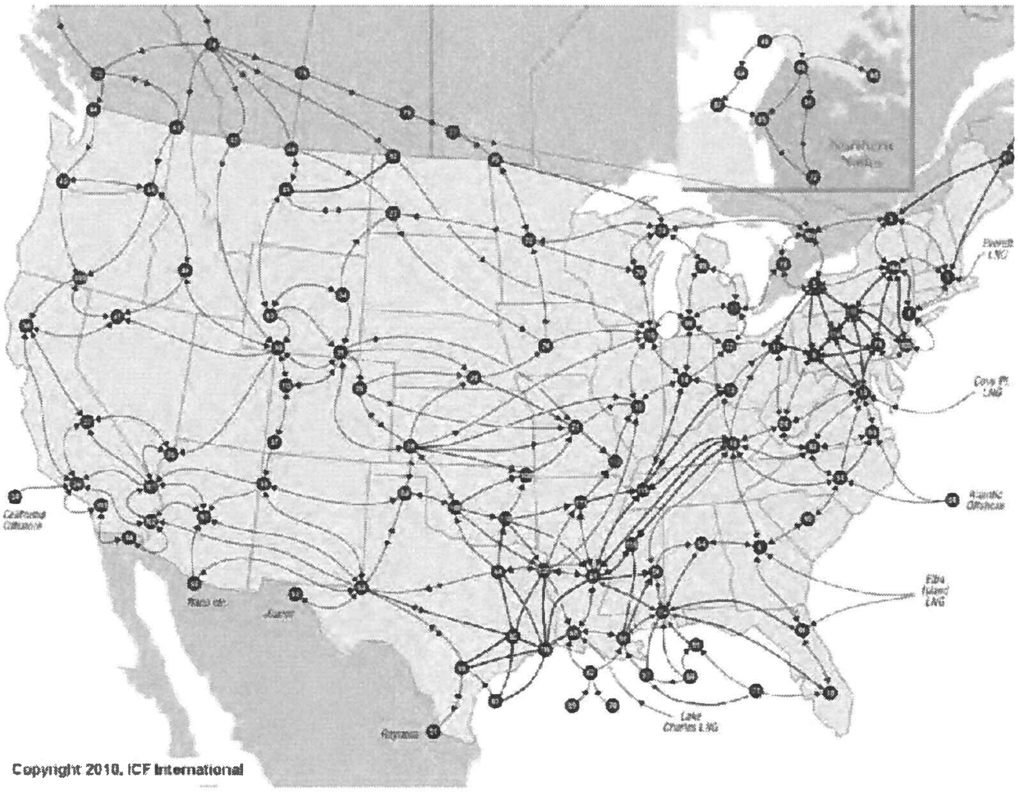
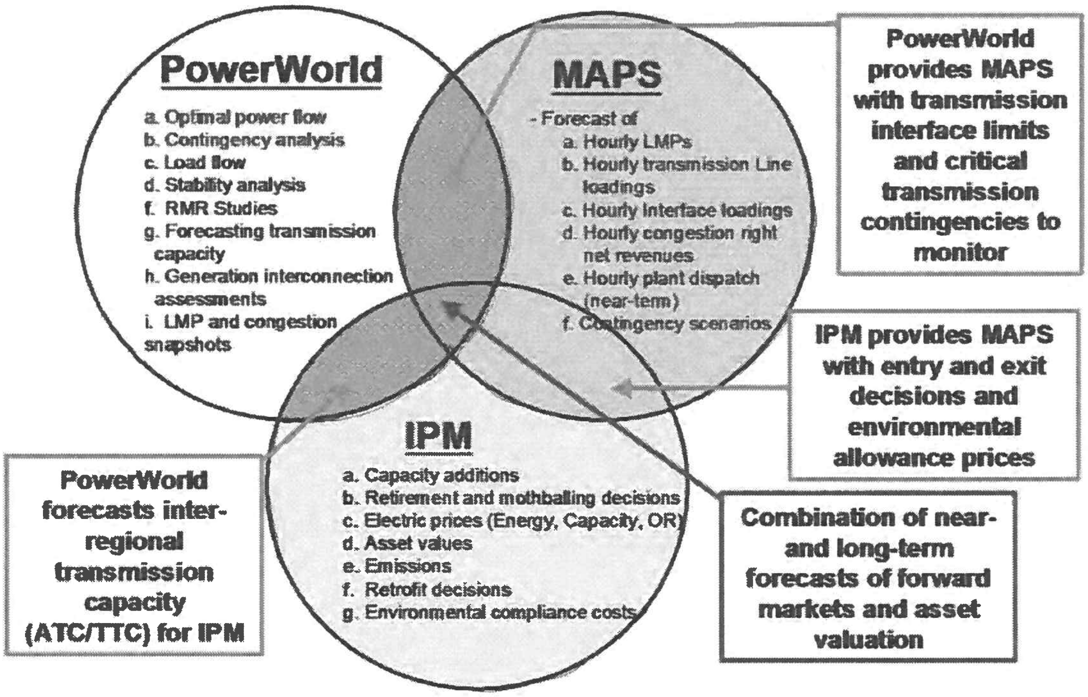


Figure 3: GMM Transmission Network



ICF utilizes several modeling tools to simulate the power markets (see Figure 4). ICF has calibrated these tools internally to produce consistent market results and often combines the tools to perform overlapping analysis. For Eversource, we have used ICF's proprietary Integrated Power Model (IPM®) to determine short and long term demand for natural gas in New England. Subsequently, ICF used GEMAPs to model New England's power grid in the cold winter and nuclear outage scenario.

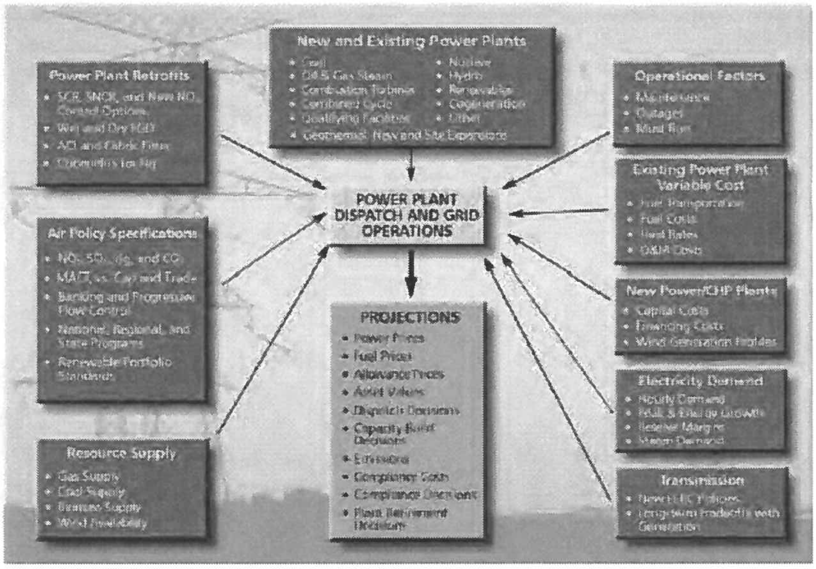
Figure 4: ICF Analytical Tools Focus on Specific Problems



The Integrated Planning Model (IPM®) - IPM® is a detailed engineering/economic capacity expansion and production-costing model of the power and industrial sectors supported by an extensive database of every boiler and generator in the nation. It is a multi-region model that provides capacity and transmission expansion plans, unit dispatch and compliance decisions, and power and allowance price forecasts, all based on power market fundamentals. IPM® explicitly considers gas, oil, and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals. Figure 5 illustrates the key components of IPM®.

IPM® uses a dynamic linear programming model the electric demand, generation, and transmission within each region as well as the transmission grid that connects the regions.

Figure 5: IPM Framework



All existing utility-owned boilers and generators are modeled, as well as independent power producers and cogeneration facilities that sell firm capacity into the wholesale market. IPM® also is capable of explicitly modeling individual (or aggregated) end-use energy efficiency investments. Each technology (e.g., compact fluorescent lighting) or general program (e.g., load control) is characterized in terms of its load shape impacts and costs. Costs can be characterized simply as total costs or more accurately according to its components (e.g., equipment or measure costs, program or equipment costs, and administrative costs), and penetration curves reflecting the market potential for a technology or program. End-use energy efficiency investments compete on a level playing field with traditional electric supply options to meet future demands. As supply side resources become more constrained or expensive (e.g., due to environmental regulation) more energy efficiency resources are used.

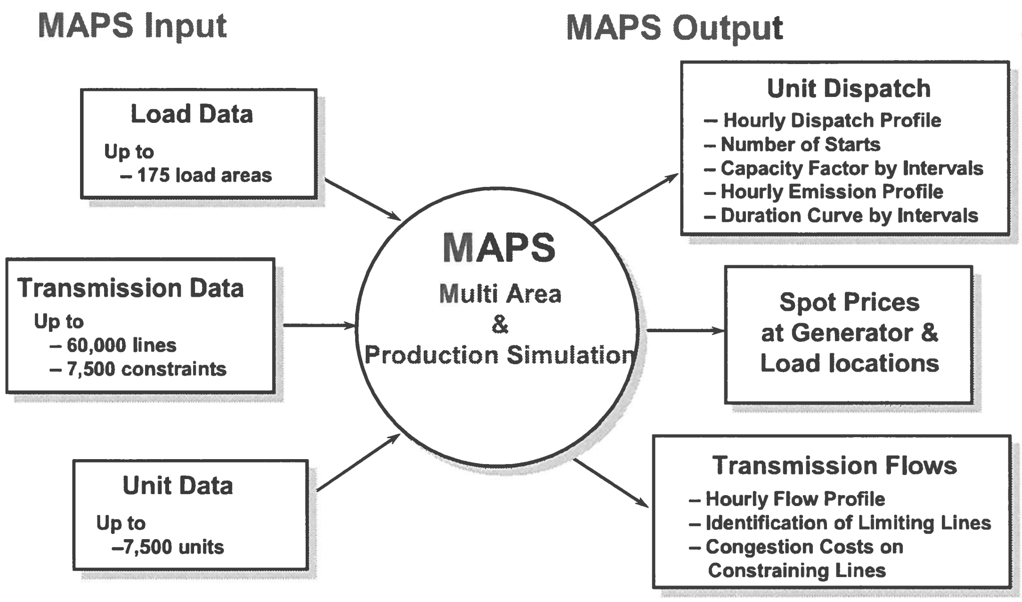
Outputs of IPM® include estimates of regional energy and capacity prices, optimal build patterns based on timing of need and available technology, unit dispatch, air emission changes, retrofit decisions, incremental electric power system costs (capital, FOM VOM), allowance prices for controlled pollutants, changes in fuel use, and fuel price impacts. Results can be directly reported at the national and power market region levels. ICF can readily develop individual state or regional impacts aggregating unit plant information to those levels.

ICF regularly analyzes transmission issues including the grid impacts of generation and bulk power transactions, transmission congestion costs, load pocket isolation issues, value of transmission assets, and the tradeoff between transmission expansion and generation expansion. The PowerWorld Simulation model and the General Electric Multi-Area Production Simulation model (GEMAPs®) are the primary tools utilized. For this Eversource work, ICF relied on the GEMAPs tool to identify the impacts of cold weather and nuclear outage scenario.

GE's Multi Area Production Simulation Model – ICF is a licensed user of GEMAPS, a highly detailed model that chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. GE-MAPS uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved alternating current (AC) load flow, to calculate the real power flows for each generation dispatch. This enables MAPS to capture the economic penalties of re-dispatching generation to satisfy transmission line flow limits and security constraints.

The outputs of GEMAPS include hourly locational marginal prices for all generator and load busses, hourly forecast of congestion across transmission lines and interfaces and associated congestion cost, system-wide congestion cost, and hourly dispatch of generation units (see Figure 6).

Figure 6: GEMAPS Framework



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03/24/16

THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 16-241

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

Petition for Approval of Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery

ORDER OF NOTICE

On February 18, 2016, Public Service Company of New Hampshire d/b/a Eversource (Eversource) filed a petition with the New Hampshire Public Utilities Commission (Commission) for approval of a proposed 20-year contract between Eversource and Algonquin Gas Transmission, LLC (Algonquin) for natural gas capacity on Algonquin's Access Northeast Project, and recovery of associated costs through a new distribution rate tariff, to be assessed on all Eversource customers. Eversource filed supporting testimony and related exhibits with the petition. The petition and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, will be posted to the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2016/16-241.html.

Eversource is a public utility operating under the laws of the State of New Hampshire as an electric distribution company (EDC), headquartered in Manchester, New Hampshire. Algonquin is an owner-operator of an interstate gas pipeline located in New England; Algonquin is owned by a parent company, Spectra Energy Corp (Spectra), a publicly-traded corporation headquartered in Houston, Texas. Algonquin has partnered with Eversource's parent company, Eversource Energy, headquartered in Boston, Massachusetts, and Hartford, Connecticut, and National Grid to develop the Access Northeast Project. In general terms, Eversource Energy's

EDC subsidiaries in Connecticut, Massachusetts, and New Hampshire and National Grid's EDC subsidiaries in Rhode Island and Massachusetts are individually seeking regulatory approval of gas capacity on the Access Northeast Project. National Grid EDC subsidiaries are also seeking approval of gas capacity on Tennessee Gas Pipeline's Northeast Energy Direct pipeline project.

In total, the Access Northeast project will provide 500,000 MMBtu/day of incremental gas transportation capacity and 400,000 MMBtu/day of incremental liquefied natural gas (LNG) storage deliverability. Under the proposed Access Northeast contract, Eversource will hold contractual entitlements for firm gas transportation and storage deliverability up to a Maximum Daily Transportation Quantity of 66,600 MMBtu/day or 7.4% of the total capacity of the project. Eversource states that this contract quantity reflects the electric load share of Eversource within the load served by all investor-owned EDCs in New England. Eversource asserts that energy cost savings resulting from the increased supply of gas capacity to New England electric generators will exceed contract-related costs by a 3:1 ratio, excluding any consideration of capacity-release revenues that will be credited to Eversource customers, thereby offering Eversource customers significant benefits justifying the recovery of the contract costs through rates. Eversource further asserts that this proposed acquisition of gas capacity on the Access Northeast Project was developed through a Request for Proposals (RFP) process that met all requirements of New Hampshire law, including the Commission's affiliate-transaction rules of N.H. Code Admin. Rules Puc 2100, and the requirements specified by the Commission in Order No. 25,860 (January 19, 2016). Eversource requests approval of the proposed contract and related mechanisms by October 1, 2016.

In its petition, Eversource seeks approval of: (1) a 20-year interstate pipeline transportation and storage contract providing natural gas capacity for use by electric generation facilities in the New England region (Access Northeast Contract); (2) an Electric Reliability Service Program (ERSP) to set parameters for the release of capacity and the sale of LNG supply made available to electric generators through the Access Northeast Contract; and (3) a Long-Term Gas Transportation and Storage Contract (LGTSC) tariff for Eversource rates, to be applied through uniform cents-per-kWh rate on all retail electric customers served by Eversource, to provide for recovery of costs associated with the Access Northeast Contract. If Eversource were to receive the approval of the Commission, Eversource would release the natural gas capacity to the electric generation market in accordance with an Algonquin Electric Reliability Service tariff, approved by the Federal Energy Regulatory Commission (FERC) as a wholesale gas tariff, that would reflect the ERSP structure approved by the Commission.

Eversource, in support of its petition, also asserts that: (1) Eversource's participation in the Access Northeast Contract does not violate the Restructuring Principles of RSA Chapter 374-F; (2) the corporate powers granted to Eversource by RSA Chapter 374-A and RSA 374:57 appear to encompass and authorize such contract execution; (3) the exercise of Commission authority is in the public interest under RSA 374:57; (4) Eversource's participation in a contract designed to improve regional and state electric reliability is consistent with the planning principles set out in RSA 378:37 and 378:38 as well as the New Hampshire 10-Year State Energy Strategy; and (5) cost recovery through rates charged to all Eversource distribution customers is allowed by and consistent with New Hampshire law, including RSA 374:57 and the provisions of RSA Chapter 374-A, as well as the Commission's plenary authority with respect to utility rates.

The filing raises, inter alia, issues related to whether Eversource has the corporate authority to enter into the Access Northeast Contract under RSA Chapter 374-A and RSA

374:57; whether Eversource's entering into the Access Northeast Contract, development of the ERSP, and assessment of the LGTSC would violate the Restructuring Principles of RSA Chapter 374-F, or any other New Hampshire law, or any federal law, including the Federal Power Act; whether the LGTSC assessment would be permitted under RSA Chapter 374-A, RSA 374:57, and RSA Chapter 378, and Commission precedential standards for ratemaking, as just, reasonable and in the public interest; whether the RFP process presented by Eversource in support of its selection of the Access Northeast Contract comports with the requirements of N.H. Code Admin. Rules Puc 2100, Order No. 25,860, and the standards of prudency applied by the Commission for such contracting; whether the assertions made by Eversource regarding expected benefits and costs of its participation in the Access Northeast Contract are supported by the evidence, including evidence of economic, engineering, and environmental costs, benefits, and feasibility; and whether ERSP and companion FERC tariff filing comport with relevant federal law, including the Natural Gas Act, and whether FERC approval should be a condition precedent for the enactment of any Commission approval.

As indicated by the Commission in Order No. 25,860, issued in Docket No. IR 15-124, the Commission will divide its review of this petition into two phases. In the first phase, the Commission will review briefs submitted by Eversource, Staff and other parties regarding whether the Access Northeast Contract, and affiliated program elements, is allowed under New Hampshire law. If the Commission were to rule against the legality of the Access Northeast Contract, this petition will be dismissed. If the Commission were to rule in the affirmative regarding the question of legality, it will then open a second phase of the proceeding to examine the appropriate economic, engineering, environmental, cost recovery, and other factors presented by Eversource's proposal. This Order of Notice opens the first phase of this review proceeding.

Each party has the right to have an attorney represent the party at the party's own expense.

Based upon the foregoing, it is hereby

ORDERED, that a Prehearing Conference, pursuant to N.H. Code Admin. Rules Puc 203.15, be held before the Commission located at 21 S. Fruit St., Suite 10, Concord, New Hampshire on April 13, 2016 at 1:30 p.m., at which each party will provide a preliminary statement of its position with regard to the question of Eversource's legal authority to enter into the Access Northeast Contract, and the legality of other features of Eversource's proposal, and any of the issues set forth in N.H. Code Admin. Rules Puc 203.15; and it is

FURTHER ORDERED, that Eversource, the Staff of the Commission, and any interested persons file legal briefs regarding the legality of Eversource's proposal no later than April 28, 2016, with reply briefs due no later than May 12, 2016; and it is

FURTHER ORDERED, that pursuant to N.H. Code Admin. Rules Puc 203.12, Eversource shall notify all persons desiring to be heard at this hearing by publishing a copy of this Order of Notice no later than March 30, 2016, in a newspaper with general circulation in those portions of the state in which operations are conducted, publication to be documented by affidavit filed with the Commission on or before April 11, 2016; and it is

FURTHER ORDERED, that consistent with N.H. Code Admin. Rules Puc 203.17 and Puc 203.02, any party seeking to intervene in the proceeding shall submit to the Commission seven copies of a Petition to Intervene with copies sent to Eversource and the Office of the Consumer Advocate on or before April 11, 2016, such Petition stating the facts demonstrating how its rights, duties, privileges, immunities or other substantial interest may be affected by the proceeding, as required by N.H. Code Admin. Rule Puc 203.17 and RSA 541-A:32,I(b); and it is

FURTHER ORDERED, that any party objecting to a Petition to Intervene make said Objection on or before April 13, 2016.

By order of the Public Utilities Commission of New Hampshire this twenty-fourth day of March, 2016,

Debra A. Howland
Executive Director

Individuals needing assistance or auxiliary communication aids due to sensory impairment or other disability should contact the Americans with Disabilities Act Coordinator, NHPUC, 21 S. Fruit St., Suite 10, Concord, New Hampshire 03301-2429; 603-271-2431; TDD Access: Relay N.H. 1-800-735-2964. Notification of the need for assistance should be made one week prior to the scheduled event.

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

Executive.Director@puc.nh.gov
alexander.speidel@puc.nh.gov
allen.desbiens@nu.com
amanda.noonan@puc.nh.gov
dhartford@clf.org
donald.kreis@oca.nh.gov
dpatch@orr-reno.com
escott@rc.com
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sgeiger@orr-reno.com
steve.frink@puc.nh.gov
tom.frantz@puc.nh.gov

Docket #: 16-241-1   Printed: March 24, 2016

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

April 13, 2016 - 1:35 p.m.
Concord, New Hampshire

RE: **DE 16-241**
EVERSOURCE ENERGY:
Petition for Approval of Gas Infrastructure Contract with Algonquin Gas Transmission, LLC.
(Prehearing conference)

PRESENT: Chairman Martin P. Honigberg, Presiding
Commissioner Kathryn M. Bailey

Sandy Deno, Clerk

APPEARANCES:

Reptg. Eversource Energy:
Matthew J. Fossum, Esq.

Reptg. Algonquin Gas Transmission, LLC:
Kenneth C. Baldwin, Esq. (Robinson & Cole)
Emilee M. Scott, Esq. (Robinson & Cole)

Reptg. Repsol Energy:
Robert Neustaedter, Esq.

Reptg. Tennessee Gas Pipeline:
Susan S. Geiger, Esq. (Orr & Reno)

Reptg. NextEra:
Christopher Roach, Esq. (Roach Hewitt)
Amie Jamieson, Esq. (NextEra)

Reptg. ENGI Gas & LNG, LLC:
Thaddeus Heuer, Esq. (Foley Hoag)

Court Reporter: Steven E. Patnaude, LCR No. 52

APPEARANCES: *(c o n t i n u e d)*

Reptg. the Coalition to Lower Energy Costs:
Anthony Buxton, Esq. (Preti Flaherty)
Robert (Benji) Borowski, Esq. (Preti...)

Reptg. the Conservation Law Foundation:
Melissa E. Birchard, Esq.

Reptg. N.H. Municipal Pipeline Coalition and the Pipe Line Awareness Network of the Northeast:
Richard A. Kanoff, Esq. (Burns & Levinson)

Reptg. the Merrimack Citizens Group:
Mary Beth Raven

Reptg. the Office of Energy & Planning:
Meredith A. Hatfield, Director

Reptg. Residential Ratepayers:
Donald M. Kreis, Esq., Consumer Advocate
Pradip Chattopadhyay, Asst. Consumer Advocate
Office of Consumer Advocate

Reptg. PUC Staff:
Alexander F. Speidel, Esq.
George R. McCluskey, Electric Division

I N D E X

P R O C E E D I N G

CHAIRMAN HONIGBERG: We're here this afternoon in Docket DE 16-241, which is Public Service Company of New Hampshire doing business as Eversource Energy's Petition for Approval of a Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details and Distribution Rate Tariff for Cost Recovery.

The Order of Notice, which I will not read, states that we are going to do this in two phases. The first phase is going to be about the legality of entering into an agreement of this nature. I know we have a lot of intervenors who have filed.

The next thing we're going to do is take appearances. What I'm going to ask is that you -- if, at this point, if you're identifying yourself, it's only if you have already filed to intervene. If there are others here today who feel they want to participate in some way, I'll ask you to wait until we've gotten through the folks who have already filed to intervene.

So, let's take appearances.

MR. FOSSUM: Good afternoon, Commissioners. Matthew Fossum, here on behalf of Public Service Company of New Hampshire doing business as Eversource Energy.

MR. BALDWIN: Good afternoon, Commissioners. Kenneth Baldwin, with my colleague, Emilee Scott, of Robinson & Cole, on behalf of Algonquin Gas Transmission, LLC.

MR. BUXTON: Good afternoon, Mr. Chairman, the Commission. Tony Buxton, of Preti Flaherty, here with Robert (Benji) Borowski, representing the Coalition to Lower Energy Costs.

MR. ROACH: Good afternoon, Mr. Chairman and Commissioner. I'm Chris Roach, from Roach Hewitt on behalf of NextEra Energy Resources, and with me is Amie Jamieson, Senior Counsel to NextEra.

MR. HEUER: Good afternoon. Thaddeus Heuer, on behalf of ENGIE Gas & LNG, LLC, from Foley Hoag.

MS. GEIGER: Susan Geiger, from the law firm of Orr & Reno, representing Tennessee Gas Pipeline, LLC.

MR. NEUSTAEDTER: Robert Neustaedter, with Repsol Energy North America Corporation.

MS. HATFIELD: Good afternoon, Commissioners. Meredith Hatfield, for the Office of Energy & Planning.

MS. BIRCHARD: Good afternoon, Chairman and Commissioner. I'm Melissa Birchard with Conservation Law Foundation.

MS. RAVEN: Mary Beth Raven, with Merrimack Citizens for Pipeline Information.

CHAIRMAN HONIGBERG: Have you filed a motion to intervene?

MS. RAVEN: I believe so.

CHAIRMAN HONIGBERG: What's your last name?

MS. RAVEN: Raven, R-a-v-e-n. My letter was on your website.

CHAIRMAN HONIGBERG: Then, you probably filed. I probably didn't see it yet.

MR. KANOFF: Good afternoon. Richard Kanoff, appearing on behalf of the New Hampshire Municipal Pipeline Coalition, and also submitting in the afternoon a petition to intervene on behalf of Pipe Line Awareness Network for the Northeast.

MR. KREIS: Good afternoon, Mr. Chairman. I am Donald Kreis, of the Office of Consumer Advocate, here on behalf of residential utility customers.

MR. SPEIDEL: Good afternoon,

Commissioners. Alexander Speidel, representing the Staff of the Commission. And I have with me the Assistant Directer of the Electric Division for Wholesale Matters, George McCluskey.

CHAIRMAN HONIGBERG: Ms. Raven, I'm looking at what we -- what our system has docketed as the list of comments and I see your name there. So, we definitely have it.

MS. RAVEN: Okay. Thank you.

CHAIRMAN HONIGBERG: Can you tell me the name of the organization you're representing again?

MS. RAVEN: Merrimack Citizens for Pipeline Information.

CHAIRMAN HONIGBERG: Is that the Town of Merrimack or the county? Okay.

MS. RAVEN: The town.

CHAIRMAN HONIGBERG: All right. Are there others here who intend to participate in this docket in some way, other than as commenters?

Is Mr. Husband here?

[No verbal response]

CHAIRMAN HONIGBERG: Oh, I should probably go through the other intervenors. I'm going to go through the list. And I know I'm -- I'm going to do them all, just to make sure I don't miss anybody.

But Algonquin is here, correct?

MR. BALDWIN: Correct.

CHAIRMAN HONIGBERG: Sunrun? Is anyone here for Sunrun?

[No verbal response]

CHAIRMAN HONIGBERG: I'll take that as a "no".

NextEra is here. Mr. Husband is not here. TransCanada or PNGTS? Anybody here for one of them?

[No verbal response]

CHAIRMAN HONIGBERG: No. Exelon?

[No verbal response]

CHAIRMAN HONIGBERG: I heard the Coalition to Lower Energy Costs. Yes. Tennessee is here. The Municipal Pipeline Coalition and PLAN are here. Repsol is here. OEP is here. CLF is here. ENGIE? ENGIE is here, right? Yes.

All right. So, we are missing some intervenors. How careless of us.

All right. The Order of Notice set a briefing schedule. So, we don't need to be talking about that. There is no technical session scheduled for after this, as far as I know.

Is that right, Mr. Speidel?

MR. SPEIDEL: That's correct, Mr. Chairman. And one of the intervenors had informed me that, due to personnel difficulties, they weren't going to be able to send a representative to this prehearing conference. But, of course, all their papers for intervention stand, and I think that's true of a lot of these folks.

I heard through the grapevine that there's a legislative hearing on this topic downtown. So, that might explain some intervenors not being here.

CHAIRMAN HONIGBERG: Competition between the Executive Branch and the Legislative Branch, and we apparently have lost, in some people's eyes. Well, they write the laws, we just execute them.

We're going to ask for people to state their preliminary positions. This is not an invitation to give us your full argument. We want to see how people line up and the types of arguments they expect to make. If we're here for long on this, then you've done it wrong. And I will ask you to stop, if you're going on too long on these issues.

We do have a lot of petitions to

intervene. Mr. Fossum, do you know yet your position on all of these interventions? Have you filed anything yet?

MR. FOSSUM: Yes. We filed a few -- well, I can run through the list, and it wouldn't be that long. I will say that, for -- at least for Ms. Raven, I did receive an e-mail from her. I understood that the Commission treated that as a public comment, not as a formal request to intervene. So, I didn't treat it that way. I'm not saying that I object or take a position. I'm saying, right at the moment, I have no response whatsoever, because I didn't read it as a request to intervene. So, I would reserve the right to respond at some point, if appropriate.

As for all of the others, the Company did file, about three or four hours ago, a couple of objections, in addition to the one relative to Sunrun that had been filed a few weeks ago. The objections that we filed were -- there was a specific objection to CLF, in light of the characterization of its participation that it had included in its petition. And there were partial objections submitted relative to the Coalition to Lower Energy Costs, to PLAN, and to the Municipal Coalition. Primarily, because it was not clear to us, from their petitions, exactly what interests they were here to represent or what they would be doing. And, so, our objections state that we -- we don't object to them generally speaking, but would request that they be required to further define the scope of their participation.

Other than that, we support the intervention of Algonquin, as the contract counterparty. I think that they're essential to this process.

And, as to the other intervenors that I haven't mentioned in the last few moments, the Company has no position on their requests to intervene.

CHAIRMAN HONIGBERG: I think, for the purposes of the first phase of this, it's less important, frankly, because anyone who wants to file a legal memorandum on the issue is going to be allowed to. And they will all have -- if you're really persuasive, it doesn't matter if you're an intervenor or not. The idea is to get this one right, understanding that someone who is aggrieved can certainly take it up to the Supreme Court.

So, we'll review the intervention situation and issue an order as appropriate at some point.

Is there anything else we need to do, Mr. Speidel, before hearing from the parties and prospective intervenors?

MR. SPEIDEL: I did pull out from my files Ms. Raven's letter or e-mail. It's relatively short. It doesn't mention her agency's or her organizational name. But it does refer to some general comments that she's made regarding her point of view of the filing made by Eversource.

So, I think it was correctly filed as a public comment, rather than a motion for intervention. There's no mention of the word "intervention" that I can find here.

CHAIRMAN HONIGBERG: Ms. Raven, is there anything else you sent in, other than that e-mail?

MS. RAVEN: No. So, I did not follow the process appropriately.

CHAIRMAN HONIGBERG: Okay. Anything else, Mr. Speidel?

MR. SPEIDEL: I think that would be all, before the initial positions are taken.

CHAIRMAN HONIGBERG: All right. Why don't we proceed then. Mr. Fossum, you get to go first.

MR. FOSSUM: Thank you. I think that the position of Eversource is succinctly set out in the petition that was filed that led to the opening of this docket.

We have entered into what we believe to be an economic and beneficial contract for the procurement of -- well, to assist, essentially, in the procurement of necessary natural gas pipeline capacity to serve the electric generation needs of this region and of this state. It's our position that this contract is economic and ultimately beneficial to customers.

This contract is in line with the activities of similar entities taking place throughout the region. There is a very active docket in Massachusetts. There's a -- well, I hesitate to call it "active", but nonetheless a state process going on in Connecticut. There are other processes going on that I'm aware of in Rhode Island and Maine. This is a regional issue. And the contract that is before you, put before you by the Company, is part of a regional solution.

It's our position that we properly and

appropriately evaluated the terms and conditions of the contract, and we did so in line with the expectations of the PUC, following the review that this Commission conducted on its own motion in IR 15-124, and that this Commission has itself recognized that there is an underlying problem to be addressed, and that we believe that this contract addresses it.

We would ask that the Commission review this contract efficiently, that it keep an appropriate scope. And that it find that this contract is reasonable, it's legal, it's an appropriately designed solution for the region's issues and for the state's issues, and that this Commission approve the Petition before it before -- on or by October 1st of this year, so that all of the other schedules that go along with the underlying project may be adhered to.

And, that's our position.

CHAIRMAN HONIGBERG: Let's go off the record for a second.

[Brief off-the-record discussion ensued.]

CHAIRMAN HONIGBERG: All right. Thank you. Mr. Baldwin.

MR. BALDWIN: Thank you, Mr. Chairman.

[Court reporter interruption and brief off-the-record discussion ensued.]

MR. BALDWIN: Thank you, Mr. Chairman. I can be brief, as instructed at the beginning of this proceeding. Algonquin Gas Transmission, LLC, adopts the positions taken by Eversource. We do believe that what Eversource has done is fully concurrent with New Hampshire statute and we support the filing.

We would like to emphasize, however, something that I'm sure the Commissioners understand already, but I think important to state again. This is a regional problem and this is a proposed regional solution. Anything that happens here in New Hampshire is affected by and will be affected by other proceedings in the other New England states, either that are a little bit ahead of New Hampshire right now or are not far behind. And we want to make sure that there is consistency amongst the state and amongst the region in this proceeding.

And we would also emphasize, as I did in the more recent letter, our desire to see that this matter be expedited as much as possible. We are cognizant of the October 1st deadline, as Eversource stated, and we would support that position also.

Thank you very much.

CHAIRMAN HONIGBERG: All right. Who was next? Mr. Buxton, I think.

MR. BUXTON: Thank you, Mr. Chairman. The Coalition to Lower Energy Costs advocates a solution on a regional basis of two pipelines with at least 2 BCF of capacity to mitigate or entirely eliminate the basis differential for New England electric and gas consumers.

The filing before us is a step in the right direction. We are concerned that Eversource is incorrect, may be incorrect, that it is an appropriately designed solution for a regional solution. The causes of that are not important. What is important is that this proceeding evaluate whether it is an appropriate solution on a regional basis. And, if not, indicate what would need to be done on the part of the State of New Hampshire and its utilities to accomplish that regional solution.

Thank you.

CHAIRMAN HONIGBERG: Mr. Roach.

MS. ROACH: Yes. Thank you, Mr. Chair. Most of what we've heard so far from the Petitioner and Algonquin, and indeed from the Coalition, has to do, I think, with issues that ought to be addressed at Phase 2, which is whether or not this particular contract is a good contract, an economical contract, a beneficial contract.

Our own view at this point, on behalf of NextEra, is that that's not what Phase 1 is about. Phase 1 is about whether or not this is lawful under state and federal law. Our firm position is that it is not lawful under either state law, under the Restructuring Act, nor did we find persuasive any of the arguments that have been posed by any other party in writing, in terms of 374-A or 374:57 dealing with capacity contracts that was promulgated back in the bankruptcy of PSNH.

Again, our view is I think pretty straightforward. It violates both the Restructuring Act and federal law, and it should be rejected.

Thank you.

CHAIRMAN HONIGBERG: Mr. Heuer, is that how you pronounce your name?

MR. HEUER: Yes. Tad Heuer, on behalf of ENGIE Gas & LNG, LLC. We similarly take the position as articulated by NextEra in some substance. As the Commission has noted, this is a two-phase proceeding. The first phase is legality, and the second phase goes to the specific contract at issue. Our position is a similar belief that this is contrary to both state and federal law, for the reasons Mr. Roach had just mentioned.

NextEra has also participated actively. As we've heard, this is a regional issue and they're seeking a regional solution. We've participated in the proceeding before the Massachusetts Department of Public Utilities, where we have objected to the Department's similar response in what is the equivalent of their Phase 1, that was their order of 15-37. And we are currently appealing that to the Massachusetts Supreme Judicial Court. That argument will be held there on the 5th of May.

So, we similarly believe that the issues before the Commission right now are those dealing with legality. Certainly, if the Commission found that this was permissible under New Hampshire law, we would be intending to participate actively in Phase 2, as to the merits of the contract, and particularly, as we noted in our Petition to Intervene, the effect of these proposals on the energy markets, and particularly ENGIE's participation therein.

CHAIRMAN HONIGBERG: Ms. Geiger.

MS. GEIGER: Thank you, Mr. Chairman. TGP understands that the first phase of this proceeding is devoted to an examination of the legal issues raised in the Order of Notice. And I won't be providing any detailed comment on those, only to note that we will be filing a brief in this docket by the deadline indicated in the Order of Notice.

But, in summary, TGP believes that the Commission does have the legal authority to approve an Eversource contract for gas pipeline capacity in support of electric reliability and lower energy costs for New Hampshire customers, and that such a contract does not violate the Restructuring principles of RSA 374-F, or any other New Hampshire law or federal law.

In addition, TGP believes that a long-term gas transportation and storage contract tariff is permissible under RSAs 374-A, 374:57, and 378. Although, we have not had time to examine the particular tariff that has been filed by Eversource to determine whether or not the rates expressed therein are just and reasonable.

The Order of Notice also raises another very important issue, and that is whether the RFP and bid evaluation process employed by Eversource, in reaching a contract with Algonquin, complies with the requirements of the Commission's Order 25,860, issued in IR 15-124. In that Order, the Commission made clear that an EDC's bid evaluation and selection process must be undertaken by entities unaffiliated with the project sponsors.

Eversource's filing in this docket clearly reveals that it participated in the evaluation and selection process that led to the Algonquin contract, which is for service on a pipeline in which Eversource's parent company has an ownership interest. We do not believe that this process comports with the Commission's order that bid evaluation and selection be undertaken by entities that are unaffiliated with the project that submitted bids in response to the RFP for transportation service.

Although TGP believes that Eversource's failure to comply with the Commission's order constitutes dismissal of Eversource's Petition, we believe that another approach could be taken in lieu of that. The Commission's website indicates that the Commission is seeking proposals from consultants to assist the Commission Staff in conducting an independent evaluation of the bids received in response to the RFP that Eversource issued in Massachusetts. That effort is being pursued simultaneously with the Commission's examination of the legal issues in this docket, and TGP believes that that course of action is appropriate and consistent with Eversource's request that the Commission issue an order by October 1st.

Another issue that TGP would note is that Staff and OCA have commenced discovery in this docket. TGP believes that it should be allowed to conduct discovery as soon as possible for the purpose of verifying the information attributed to TGP in the documents that Sussex and Eversource reviewed in evaluating bids provided in response to the Mass. RFP. Assuming that this docket proceeds to Phase 2, TGP believes that discovery on other relevant issues should occur as soon as possible.

And, although the Commission's Order of Notice did not provide for a technical session to discuss a procedural schedule for Phase 2, TGP believes that such a session should be scheduled soon and need not wait until after the legal issues are decided.

And, lastly, related to the issue of discovery, is the outstanding confidentiality pleadings that have been filed in this docket. TGP would request that the Commission rule on them as soon as possible, so that the parties can gain a better understanding of what information they will be able to access and use in this proceeding, as well as the scope of any protective orders that will be issued to protect information from public disclosure. In addition, TGP would note that it needs access to as much information as possible to meaningfully participate in this docket.

Thank you.

CHAIRMAN HONIGBERG: Mr. Neustaedter.

MR. NEUSTAEDTER: We don't take a --

[Court reporter interruption.]

MR. NEUSTAEDTER: At this time, Repsol doesn't take any position with regard to the legality of the contract. However, as a owner of capacity in the Canaport LNG facility and majority owner of capacity on Maritimes & Northeast Pipeline, we believe that the use of existing transportation -- or, pipeline facilities into the region, along with the imported or the use of imported LNG, is a better solution for New Hampshire's gas needs, rather than the construction of new and expensive pipeline facilities.

CHAIRMAN HONIGBERG: Ms. Hatfield.

MS. HATFIELD: Thank you, Mr. Chairman. The Office of Energy & Planning does not have a position on the legality of the proposal at this time, but we will participate in the process. Thank you.

CHAIRMAN HONIGBERG: Ms. Birchard.

MS. BIRCHARD: Thank you, Mr. Chairman. CLF believes that the Eversource contract is illegal under state and federal law. New Hampshire's electric utility restructuring law is premised on the foundational principles of an unambiguous purpose of establishing competitive markets, in which electric generation is separated from transmission and distribution services.

Indeed, in furtherance of this purpose, Eversource is currently moving towards divestiture of its remaining generation assets. The Restructuring law provides no allowance or exception for the kind of arrangement that Eversource now asks the Commission to approve.

CLF also takes the position that approval of this contract would violate federal law and the project should be rejected.

CLF would ask to reserve the right to comment on other aspects of the Eversource proposal at a later time. Thank you.

CHAIRMAN HONIGBERG: Mr. Kanoff.

MR. KANOFF: Good afternoon. On behalf of the Coalition, we don't believe that the proposal is consistent with statutes or precedents. We don't believe that there's a regional need for new pipelines. And we don't believe that electric ratepayers should pay for gas infrastructure.

With respect to Pipe Line Awareness Network for the Northeast, they take a similar position.

CHAIRMAN HONIGBERG: Hardly surprising. Mr. Kreis.

MR. KREIS: Thank you, Mr. Chairman. On behalf of residential utility customers, the Office of Consumer Advocate emphatically and unambiguously opposes this Petition. Twenty-eight years ago, a bankrupt New Hampshire electric utility went before the New Hampshire Supreme Court to argue the absurd proposition that, thanks to the utility's obdurate refusal to abandon its dream of nuclear grandeur, its shareholders were entitled to a whopping 19 percent return on equity. The Court's opinion, authored by a soon-to-be-very-famous jurist by the name of David

Souter, emphatically and unambiguously rejected the utility's argument. The Company's logic, wrote Justice Souter, "would provide the Company not with a reasonable rate of return, but the plenary indemnification" --

CHAIRMAN HONIGBERG: Mr. Kreis, slow down just a little. Mr. Patnaude needs to be able to keep up with you.

MR. KREIS: Understood. Justice Souter said that "that return on equity would provide the Company, not with a reasonable rate of return, but with plenary indemnification, nothing less than a shifting of the entire risk from the investors to the ratepayers."

We won the battle in 1988. But, since then, we, residential electric customers, have been losing the war. The Rate Agreement, the Restructuring Agreement, the Scrubber, and now here we are again.

This time, the request for plenary indemnification comes in the form of Eversource's request to double down on natural gas for 20 years and guarantee that consumers will cover the costs no matter what. No matter that, when this possibility first came before the Commission last year, Eversource was touting this idea as an important reliability initiative. Now, the justification is no longer reliability, but wholesale price effects.

The Eversource Petition asks the Commission for a finding that its proposed Access Northeast deal "is in the public" -- "will provide net benefits at a reasonable cost to Eversource customers in the form of lower electric retail prices." We believe the Company will not be able to sustain its burden of proof when it comes to such a proposition.

Like other parties here today, we will argue strenuously that Eversource lacks the authority under New Hampshire law to impose this 20-year burden on its customers. We will further demonstrate that, even if the Commission could approve what Eversource is requesting here, as a matter of law, such action would be preempted by both the Federal Power Act and the Natural Gas Act. We look forward to presenting that issue in due course to the New Hampshire Supreme Court, even if Justice Souter isn't there anymore.

We share the concerns of many in this room that have to do with how competitive a solicitation and selection process Eversource could possibly have conducted, given the breathtaking speed with which it unfolded. And, of course, the fact that the chosen project happens to be one in which Eversource has a 40 percent ownership interest.

And, of course, for the reasons OCA has now twice stated in writing, we are concerned about the request of the two contracting parties to treat essentially all of the important information in this docket as secret.

Twenty years after the adoption of the Restructuring Act, it looks like the customers of the Company, formally known as "Public Service Company of New Hampshire", are finally going to be served by a truly restructured utility. Consumers have paid dearly to get PSNH to that point. And, now, Eversource is here asking to replace competition with more of the same old 1980s style plenary indemnification, this time in the guise of a firm natural gas transportation deal. It's illegal, it's unjust, and it's unreasonable.

CHAIRMAN HONIGBERG: Mr. Speidel.

MR. SPEIDEL: Thank you, Mr. Chairman and Commissioners. We certainly, as Staff, look forward to filing a legal memorandum, as specified in the Order of Notice, by April the 28th. With some level of forbearance, we'd like to delve a little bit into some Phase 2 type matters.

CHAIRMAN HONIGBERG: You wouldn't be the only one who did. So, feel free.

MR. SPEIDEL: I appreciate that. Thank you very much, Mr. Chairman.

Just on the basis of what is out there and current and what's of interest to Staff, and I think of all the parties. A letter was filed by the Governor dated April the 13th, meaning today, regarding this instant docket. And I thought that was worthy of mention. I don't know if the Commissioners have had a chance to read it or not. It just came in around noontime.

CHAIRMAN HONIGBERG: Mr. Speidel, if it came in today, the chances of it having made it to us are really pretty slim.

MR. SPEIDEL: Well, I can give you a little bit of a sneak preview.

CHAIRMAN HONIGBERG: I can't wait.

MR. SPEIDEL: So, the Staff agrees with the Governor that it is appropriate and required that the filing party, in this instant proceeding, to some level compare its proposal with alternatives, in order to demonstrate that the proposed solution is most cost-effective for consumers. And the Governor's letter refers to RSA 378:38, the Least Cost Integrated Resource Plan statute. And Staff agrees with that approach. We think it's very much appropriate and necessary.

In turn, we would hope and expect that the various entities that have filed to intervene in this proceeding, upon receiving intervention, or in the form of pleadings that they might make in the legal memorandum section, they should advocate for alternative approaches that interest them. I think that's important. And they should do so with specificity.

We are fully supportive of having these entities file detailed alternative proposals that would be of use for the Commission and the Staff in examining the Petition made by the Company in this proceeding. So, we think that could be a very effective means of gauging the cost-effectiveness of this proposal, and for making sure that no stone left is unturned in makings sure that alternatives are considered fairly.

In this way, we can meet the record burden for this proceeding, not only on the terms that are elucidated within the public interest standard that is being considered, but also in terms of the Least Cost Planning statute. So, we believe that's useful.

And, also, even in this early phase, as mentioned by one of the parties, I think it was Ms. Geiger, on behalf of TGP, the Staff is seeking the services of an independent consultant. I think Mr. McCluskey could give a little summary of what Staff's thinking is on that.

Thank you.

CHAIRMAN HONIGBERG: Mr. McCluskey.

MR. McCLUSKEY: Thank you, Commissioners. The order issued by the Commission in IR 15-124 does not require New Hampshire EDCs to purchase capacity from project developers. Rather, the order details the Commission's preferred acquisition process should an EDC decide to procure gas capacity for ultimate benefit of its customers. Under that process, any acquisition of gas capacity by a New Hampshire EDC is to be undertaken through a competitive solicitation, with the evaluation, selection of competing projects administered by entities that have no affiliation with any of the project developers.

That expectation has not been met in the instant proceeding. The capacity contract submitted for Commission approval in this docket is the product of a competitive solicitation issued by Eversource's Massachusetts EDCs, in which evaluation and selection were conducted not by an independent entity, but by Eversource's EDCs, even though the parent company of those EDCs holds a 40 percent stake in one of the competing projects.

Rather than recommend that Eversource's filing be thrown out on the ground that it's not compliant with the Commission's order, the Staff recommends that the bids submitted in response to the Massachusetts RFP be reevaluated by an independent consultant working under Staff's direction. An independent evaluation of the bids is also supported by a review of Eversource's evaluation materials in this docket, which we believe lack objectivity.

Thank you.

CHAIRMAN HONIGBERG: Mr. Speidel, anything else?

MR. SPEIDEL: Well, in summary, Staff would like to express its opinion that it does not object to any of the motions for intervention, if they were to be granted intervention on Subpart II grounds.

Certainly, in the case of -- I would

recommend that Ms. Raven, if she wishes to have a late filing for intervention, she still has a window to do so, and it would be under the Commission's discretion to entertain it or not. But it would have to essentially state the grounds for her intervention.

CHAIRMAN HONIGBERG: Ms. Raven, is it your desire to intervene and participate in this proceeding or is it your desire instead to be -- to follow it, observe, and provide comment?

MS. RAVEN: At this point, I think providing comment would be the most appropriate thing.

CHAIRMAN HONIGBERG: Thank you. And you can certainly -- you can speak with Mr. Kanoff, you can speak with Mr. Speidel about what your options are in that regard.

MS. RAVEN: Okay.

CHAIRMAN HONIGBERG: Mr. Fossum, since you are the moving party here and ultimately the burden of proof, is there anything you want to add at this point?

MR. FOSSUM: Only just one thing. There were a few mentions in the room relative to the confidential treatment or the outstanding request therefore and objections to it. The only comment I would make on that is that I don't believe that that is an issue that, at the Phase 1 part of this, really needs to be addressed by the Commission.

I think the Commission has made quite clear, both in its order in 15-124 and the Order of Notice here, that, if the legality hurdle is not overcome, then the Petition would be dismissed, and, essentially, everything that was filed would become a moot point anyway.

So, my only suggestion is that, at this point, that there's no cause for the Commission to take up that issue, and that it can be done down the road, once there's a better idea whether this proceeding will actually continue.

CHAIRMAN HONIGBERG: All right. I know there's a group of people in the back, and I'm not sure if they are just here to watch the festivities or if someone back there is interested in participating in the proceeding. If there is someone back there who wishes to intervene and become part of this, I would encourage you to, again, approach Mr. Speidel, or one of the other lawyers in the room who are experienced, Mr. Kreis, for example, about what the options are for participation.

I know we have -- oh, Mr. Speidel.

MR. SPEIDEL: Yes. If I may? There is a sign-up sheet. I would invite anyone who would like to have some level of marking down as a commenter or as an intervenor or as a potential intervenor, please sign up this sheet, if you wouldn't mind, by the close of today. Thank you.

CHAIRMAN HONIGBERG: The next step is for people to file legal memoranda. I mean, we have other things we can do, and I've heard -- we've heard the recommendations from some of you about things we can do in the interim, and I understand those.

Certainly there are a lot of people in this room who agree with others in the room. There is nothing preventing you from signing onto one legal memorandum or two legal memoranda that take the same positions. I mean, there appears to have been some, you know, some cooperation in advance, because I think most of you gave your adverbs and adjectives to Mr. Kreis before we started today.

And, so, I mean, if you want to formalize some of that, and reduce the number of filings, we would certainly have no objection to that. But, of course, you all have the positions that you want to articulate regarding legality, some of you are going to want to talk preemption, some of you are going to want to focus on state law. There's lots of different ways to talk about this, and they're all significant and all potentially important for us to hear and understand.

But, again, if you can cooperate and reduce the number of filings, that could be a very good thing, because your voice can be just as powerful when multiplied that way.

Is there anything else that we need to do? Mr. Kreis.

MR. KREIS: Thank you, Mr. Chairman. Lest my silence deemed to be acquiescence, I would like to express a concern about the Petitioner's insistence, and we heard articulated by Algonquin as well, that this proceeding be reduced to a final order by October 1st. I do not believe that it is possible to conclude this docket by October 1st. And I think that is an issue that we ought to confront sooner, rather than later.

CHAIRMAN HONIGBERG: Well, I think the typical way of setting schedules is for the parties to discuss a schedule in a technical session. And, if they can't agree, then they seek the assistance of the Commissioners. I think it's premature for us to weigh in on that.

I understood Mr. Fossum's and Mr. Baldwin's -- I think your word was "insistence", I hear those as requests. I understand them to be requests. And, as we go, we will see how things are proceeding.

I know that Staff has been working on things that are going to be relevant or would be relevant to Phase 2, if we get there. Others certainly can as well, and I expect are preparing things that they would be using in Phase 2, should we get there. I think, to the extent that we can advance the ball in ways, we will discuss that with Staff and see if we can do other things.

So, I heard Ms. Geiger's suggestion that a technical session be scheduled, that may well be a good idea, and we'll discuss that with Staff as well.

MR. KREIS: I think, Mr. Chairman, that probably is a good idea. The reason I raise this now is the fact that there is not presently a technical schedule -- a technical session schedule, so the ordinary conversation that would take place as soon as we're done here will apparently not take place. And I'm concerned that October 1st is very, very soon.

CHAIRMAN HONIGBERG: Now, I understand we didn't notice a technical session. So, those who would be interested in participating might feel left out if they were not present. It sounds like some of them wanted to be at the Legislature anyway.

But there's nothing preventing parties from discussing with each other an appropriate schedule and being prepared when the technical session starts to do have something like that.

Mr. Speidel.

MR. SPEIDEL: In light of that, there was some level of informal understanding that quite a few of the parties might not be able to make it all the way up to New Hampshire to just talk in a room about a procedural schedule.

What Staff was going to do, given the framework that we have at hand, number one, we have to file the legal memoranda first and foremost. So, that's going to be a lift, that's going to take some time. Whatever schedule features we've got, they're going to take place after the April 28th deadline for that. And, on top of that, once we have an idea of who's intervening and who will be granted intervention, who will be on the service list, we can simply send out emails to the service list inquiring as to whether folks would like to sign on to a procedural schedule. And that would include folks that are in Maryland and other parts of the country that can participate in such an effort remotely, rather than being here in person.

CHAIRMAN HONIGBERG: Understood. Yes, Mr. Roach.

MS. ROACH: Thank you, Mr. Chairman. I just wanted to note for the record, NextEra objects to delaying the issuance of an order on the confidentiality issues. I think, in the prior order from the Commission, the Commission said "We are not going to rule on the legality of any proposal in the hypothetical. We want an actual application that can be reviewed in detail by the parties, and then submission of legal memoranda." We also have the parties suggesting a very rapid procedural schedule here.

And, I think, in light of both of those, we would request to be able to see that information sooner rather than later.

CHAIRMAN HONIGBERG: I understand the

request. Were you quoting from the order in what you just said, because I don't think you were?

MR. ROACH: I believe that the prior order, not the Order of Notice --

CHAIRMAN HONIGBERG: I know which order you're referring to. But were --

MR. ROACH: The prior order said --

CHAIRMAN HONIGBERG: Mr. Roach, let me talk right now.

MR. ROACH: Certainly.

CHAIRMAN HONIGBERG: Were you quoting from that order?

MR. ROACH: I was not. I was quoting from -- I was reciting from memory.

CHAIRMAN HONIGBERG: Yes. I think, if you pull that order, I'm not 100 percent sure it says exactly what you think it said. I think it said we would "wait for an actual petition to be filed". And I think, without parties to contest each other, it's like the sound of one hand clapping, and I think that's what we're looking for. I'm not sure it went quite as far as you think it went in the sentence that you were paraphrasing.

And I could be wrong. I don't have it

in front of me, and I may be misremembering what's in that order. But I think we're going to get some good quality legal memoranda on this, and that's what we're going to need to decide the initial issue.

We'll issue an order on confidentiality as soon as we feel it's appropriate to do so.

MR. ROACH: Thank you.

CHAIRMAN HONIGBERG: Is there anything else that needs to be brought to our attention or need to deal with? Mr. Fossum.

MR. FOSSUM: Just one last thing on the confidentiality. In light of the fact that this is one of a number of similar proceedings going on in the region, a good many of those issues have been addressed at some length elsewhere, particularly in the Massachusetts proceeding. And I'd simply encourage the Commission to review what has happened down there relative to confidentiality, and potentially see that as a -- I won't say a "model", but as something that could be brought to New Hampshire.

CHAIRMAN HONIGBERG: Instructive. You're saying it would be instructive?

MR. FOSSUM: Yes. And which a great many of the folks in this room are already familiar.

CHAIRMAN HONIGBERG: Okay. Anything else that anyone wants to bring to our attention at this time? Yes.

MR. BALDWIN: Mr. Chairman, just one other thing. I did hear you mention that, for the purposes of Phase 1 of this proceeding, certainly anyone who's expressed interest in intervening will be granted that ability.

Does the Commission anticipate the ability of the parties to speak further on perhaps opposition to those requests, as and if we get to Phase 2?

CHAIRMAN HONIGBERG: I'm not sure I understand the question.

MR. BALDWIN: Well, I guess, to the extent that the Commission has already determined that those who are seeking party or intervenor status in this proceeding are going to be allowed to file a brief in Phase 1. That said, there may be some -- or, I guess the question is, will there be an opportunity to oppose intervention requests at Phase 2, if we get there?

CHAIRMAN HONIGBERG: I think it depends on how we deal with the intervention requests at this time. I think it's quite possible that we will rule on the intervention requests with both phases in mind. That would be the plain vanilla way that we would deal with intervention requests in the normal course. We would assume that the matter was going to proceed all the way through all of its phases and grant intervention as appropriate, if there needs to be limitations on people's participation or if people need to be denied intervenor status.

If we do something else, then I think it will probably invite those who are concerned about levels of participation in Phase 2 to raise those concerns at that time.

Mr. Kreis, you look like you want to say something? Oh, sorry. Is that -- all right.

MR. BALDWIN: It is. Thank you.

CHAIRMAN HONIGBERG: Anything else that people want to bring to our attention at this time?

[No verbal response]

CHAIRMAN HONIGBERG: If not, thank you all. We will adjourn.

(Whereupon the prehearing conference was adjourned at 2:20 p.m.)

04/17/15

THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

IR 15-124

ELECTRIC DISTRIBUTION UTILITIES

Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire

ORDER OF NOTICE

The Commission announces an investigation, pursuant to RSA 365:5, RSA 374:3, RSA 374:4, RSA Chapter 374-F generally, and RSA 374-F:8 specifically, into potential approaches involving New Hampshire's electric distribution utilities (EDCs) to address cost and price volatility issues currently affecting wholesale electricity markets in New Hampshire.

Electric Utility Restructuring legislation, codified as RSA Chapter 374-F, passed in 1996, included the following statements of purpose in RSA 374-F:1:

> The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment.

Over the subsequent two decades, competitive electricity markets have developed in New Hampshire, at both the wholesale and retail levels. At the wholesale level, EDCs have selected among competing offers of power to serve EDC Default Service loads, on the basis of lowest wholesale cost. At the retail level, the resultant wholesale costs have been passed to Default Service customers of the EDCs. Also, retail customers have been free to select from among competitive electric power suppliers (CEPS) to supply their energy needs, instead of taking the

Default Service offerings of EDCs. Until recently, market competition at the wholesale and retail levels has tended to keep electricity prices at reasonable levels for New Hampshire consumers.

The past two years, however, have seen significant transitions in New Hampshire's wholesale and retail electricity markets, and those of the New England region generally. ISO-New England (ISO-NE), the regional electricity market administrator, has pointed to an increasing dependence on natural gas-fueled generation plants within the region over the past two decades as aging coal, oil, and nuclear plants have been retired. During recent winters, significant constraints on natural gas resources have emerged in New England, despite abundant natural gas commodity production in the Mid-Atlantic States and elsewhere. These constraints have led to extreme price volatility in gas markets in the winter months in our region, which, in turn, have resulted in sharply higher wholesale electricity prices.[1] Correspondingly, rates charged for Default Service to certain EDCs' customers have escalated sharply in New Hampshire for winter period service. *See* Order No. 25,719 (September 29, 2014) and Order No. 25,720 (October 3, 2014). Overall, the average retail price of electricity in New England is the highest in the continental United States, posing a threat to our region's economic competitiveness. (*See* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a).

The Commission has a fundamental duty to ensure that the rates and charges assessed by EDCs are just and reasonable. RSA Chapter 378. We share ISO-NE's view, expressed in its 2014 Regional System Plan, that the potential development of additional natural gas resources for the benefit of the electricity supply in our region should be carefully considered. The consideration of such approaches was also endorsed by our State's Ten-Year Energy Strategy (Energy Strategy),

[1] *See, e.g.,* ISO-NE 2014 Regional System Plan, at pp. 124-147, available here: http://www.iso-ne.com/system-planning/system-plans-studies/rsp

available here (*see* pp. 46-47): http://www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf

The Commission also takes note of the Energy Strategy's multi-level approach to addressing New Hampshire's energy challenges, including the fostering of energy efficiency, examining renewable generation resources (including "behind-the-meter" Distributed Generation resources), and considering other innovative means of seeking to reduce New Hampshire's dependence on fossil-fueled electricity. To that end, the Commission is engaged in an Energy Efficiency Investigation, Docket No. IR 15-072, with Staff offering a Straw Proposal for an Energy Efficiency Resource Standard, which is currently under stakeholder review. Also, the Commission is engaged in a general review of Default Service procurement processes for our State's EDCs, Docket No. IR 14-338, in an effort to examine potential responses to the wholesale electricity market challenges facing New Hampshire EDCs.

A targeted Staff investigation to examine the gas-resource constraint problem that is affecting New Hampshire's EDCs and electricity consumers generally may yield potential solutions to these market issues. To that end, we direct Staff to inquire with the EDCs – which are to be mandatory participants in this investigation– regarding potential means of addressing these market problems, using legal authorities such as, but not limited to, RSA Chapter 374-F; RSA Chapter 374-A; RSA Chapter 378; RSA 378:37-41; and RSA 374:57. Staff should also solicit the views of other stakeholders in its inquiry. Staff is to provide a report to the Commission, no later than September 15, 2015. (Other stakeholders, and the EDCs, are also invited to make reports by September 15, 2015, if they so choose.) Staff may retain a consultant to assist it in its effort. Staff shall conduct a public stakeholder meeting at the Commission on May 12, 2015, at 10:00 a.m. to enable interested persons to make their views regarding this Investigation known to Staff.

Based upon the foregoing, it is hereby

ORDERED, that the Commission Staff investigate the matters delineated herein, with a report to be made to the Commission no later than September 15, 2015, for which a Staff consultant may be retained, and contribute to the report; and it is

FURTHER ORDERED, that participation by Public Service of New Hampshire d/b/a Eversource Energy, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities, and Unitil Energy Systems, Inc., collectively, "EDCs," is mandatory for this Investigation, and that these utilities shall respond to Staff's inquiries, subject to protective treatment as appropriate, pursuant to RSA 91-A; and it is

FURTHER ORDERED, that Staff make inquiries of other stakeholders as needed in its investigation, with responses afforded protective treatment as appropriate, pursuant to RSA 91-A; and it is

FURTHER ORDERED, that Staff shall conduct a public stakeholder meeting at the Commission's offices at 21 South Fruit Street, Concord, New Hampshire, to be held on May 12, 2015, at 10:00 a.m., at which time interested persons may make statements of position regarding the matters considered in this Investigation, and at which time the EDCs shall appear.

By order of the Public Utilities Commission of New Hampshire this seventeenth day of April, 2015.

Debra A. Howland
Executive Director

Individuals needing assistance or auxiliary communication aids due to sensory impairment or other disability should contact the Americans with Disabilities Act Coordinator, NHPUC, 21 S. Fruit St., Suite 10, Concord, New Hampshire 03301-2429; 603-271-2431; TDD Access: Relay N.H. 1-800-735-2964. Notification of the need for assistance should be made one week prior to the scheduled event.

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

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Docket #: 15-124-1 Printed: April 17, 2015

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

STATE OF NEW HAMPSHIRE

Inter-Department Communication

DATE: July 10, 2015
AT (OFFICE): NHPUC

FROM: Alexander F. Speidel, Staff Attorney

SUBJECT: Gas Capacity Acquisitions by N.H. Electric Distribution Utilities

TO: George R. McCluskey, Assistant Director, Electric Division
Interested Stakeholders (IR 15-124)

Staff welcomes comments regarding this memorandum, e-mailed to alexander.speidel@puc.nh.gov, by August 10, 2015 (during the pendency of the Staff investigation and for incorporation into Staff's September 15 Report); these comments will be posted here:
http://puc.nh.gov/Electric/Investigation_into_Potential_Approaches_to_Mitigate_Wholesale_Electricity_Prices.html

In the context of the ongoing Staff Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire, docketed in Docket No. IR 15-124, the question has been raised by certain stakeholders: Do New Hampshire's Electric Distribution Utilities (EDCs), under existing New Hampshire law, have the corporate authority to enter into contractual arrangements to acquire pipeline, and/or Liquefied Natural Gas (LNG)-related, capacity to benefit their customers? If so, how can the costs of such arrangements be justified, and recovered from EDC customers through Commission-approved rates?

In examining this question from a legal perspective, Staff applies traditional New Hampshire principles of statutory interpretation, namely: the New Hampshire Supreme Court first looks to the language of a statute itself, and, if possible, construes that language according to its plain and ordinary meaning; the Supreme Court interprets statutes and regulations in the context of the overall statutory and regulatory scheme and not in isolation, with a goal to apply statutes in light of the Legislature's intent in enacting them, and in light of the policy sought to be advanced by the entire statutory and regulatory scheme; the Supreme Court construes statutes, where reasonably possible, so that they lead to reasonable results and do not contradict each other; when interpreting a statute, the Supreme Court must give effect to all words in the statute and presume that the legislature did not enact superfluous or redundant words; the Supreme Court reviews legislative history to aid its analysis when statutory language is ambiguous or subject to more than one reasonable interpretation. (*See Appeal of Old Dutch Mustard Co., Inc.*, 99 A.3d 290 (N.H. 2014); *State v. Collyns*, 99 A.3d 300 (N.H. 2014)).

This memorandum will not directly address the economic questions surrounding the advisability of EDCs making investments in gas capacity on behalf of their customers, presumably to reduce wholesale electric power costs prevailing in New England, beyond the role of such analysis as a factor in Commission decision-making. Also, this memorandum will focus on New Hampshire law, leaving aside the question of federal preemption (under the Federal Power Act, Natural Gas Act, and allied statutes) for now. Staff is of the opinion that any EDC participation in gas-capacity acquisition should be voluntary, as a private-sector business decision of each EDC, and not mandated by the Commission *a priori*. Staff considers such voluntary, permissive participation to pose less of a litigation risk on the question of federal preemption than a State-mandated program, in that the Commission's role in the wholesale markets in a voluntary approach would be in its traditional role as regulator, rather than as a direct market participant directionally enacting a specific approach. On this basis, Staff analyzes the potential legal issues faced by the Commission in deciding whether to approve a hypothetical EDC petition to acquire gas capacity, and recovery of related costs, in sequence.

Issue 1: Does the Electric Utility Restructuring statute (RSA Chapter 374-F) prohibit EDCs from acquiring gas capacity?

The threshold question regarding any potential proposal for gas capacity acquisition by a New Hampshire EDC is whether the Electric Utility Restructuring statute, which was originally enacted in 1996 with subsequent amendments, categorically prohibits such activity. RSA 374-F:3 outlines the Restructuring Policy Principles meant to govern the Commission's approach to electric market matters. RSA 374-F:3, III plainly states: "Generation services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services which should remain regulated for the foreseeable future. However, distribution service companies should not be absolutely precluded from owning small scale distributed generation resources as part of a strategy for minimizing transmission and distribution costs." An acquisition of gas capacity, of the type referred to by certain stakeholders, most certainly does not qualify as a small-scale distributed generation resource. The Commission may determine that this Restructuring Policy Principle is prescriptive and overrides any other statute related to the Commission's jurisdiction, including any other Restructuring Policy Principle. On this basis, the Commission could reasonably conclude that an EDC acquisition of gas capacity for the use of gas-fired generators and, by extension, the benefit of EDC customers, would violate the principle of separation of distribution and generation functions, and is therefore prohibited.

However, the Restructuring Policy Principle presented in RSA 374-F:3, III related to separation of generation and distribution functions does not stand in isolation. RSA 374-F:3, I states: "Reliable electricity service must be maintained while ensuring public health, safety, and quality of life." RSA 374-F:3, VI: "A nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system may be used to fund public benefits related to the provision of electricity. Such benefits, as approved by regulators, may include, *but not necessarily be limited to*, programs for low-income customers, energy efficiency programs, funding for the electric utility industry's share of commission expenses pursuant to RSA 363-A, support for research and development, and investment in commercialization strategies for new and beneficial technologies" (emphasis added). RSA 374-F:3, XII: "New Hampshire should work with other New England and northeastern states to accomplish the goals of restructuring. Working with other regional states, New Hampshire should assert maximum state authority over the entire electric industry restructuring process." RSA 374-F:3, VIII: "Continued environmental protection and long term environmental sustainability should be encouraged….As generation becomes deregulated, innovative market-driven approaches are preferred to regulatory controls to reduce adverse environmental impacts."

The Commission may find that a proposal by an EDC to acquire incremental gas capacity, for the use of gas-fired generators, could enhance power system reliability (especially in winter when existing gas capacity is constrained), and thus help the EDC meet its duty to provide reliable service under RSA 374:1; provide public benefits related to the provision of electricity (e.g., less price volatility, enhanced winter reliability, etc.); and serve as an element of New England-wide cooperation to reduce gas capacity constraints in order to provide for the displacement of oil and coal-fired electric generation by cleaner gas-fired electric generation. If the Commission were to decide that these goals were congruent with various Restructuring Policy Principles, and that these principles were not overridden by the single principle of generation-distribution separation in RSA 374-F:3, III, it could conclude that RSA Chapter 374-F does not preclude such an EDC capacity purchase. Furthermore, an EDC making such a proposal could argue that provision of gas capacity to unaffiliated merchant generators does not violate the functional separation principle of RSA 374-F:3, III in the first instance, in that New Hampshire EDCs would not actually acquire the gas capacity for their own use, but rather, would make such capacity available for the use of merchant generators in a bilateral transaction. If the Commission were to accept this broader approach, it could rule that EDC acquisition of gas capacity for the benefit of gas-fired generators does not violate RSA Chapter 374-F.

In addition, RSA 374-F:3, V(e) offers a path for EDCs to potentially seek approval of gas capacity acquisition programs in the context of their provision of Default Service supply to their customers: "Notwithstanding any provision of subparagraphs (b) and (c), as competitive markets develop, the commission may approve alternative means of providing transition or default services which are designed to minimize customer risk, not unduly harm the development of competitive markets, and mitigate against price volatility without creating new deferred costs, if the commission determines such means to be in the public interest." If the Commission were to evaluate the costs and benefits of a gas capacity acquisition program designed to benefit EDC's Default Service customers with lower electricity costs, and found that such means were to be in the public interest using these criteria, it would be a finding embedded within the terms of the Restructuring Statute itself, and could likely be upheld against challenge under RSA 374-F:3, III.

Issue 2: Do New Hampshire EDCs have the corporate power under RSA Chapter 374-A, and allied statutes, to acquire gas capacity?

RSA Chapter 374-A is an act, originally passed in 1975, "Authorizing Electric Utilities to Participate in Electric Power Facilities." Under RSA 374-A:1, II, "Domestic electric utility" is defined as "an electric utility resident in, or organized under the laws of this state." All of New Hampshire's EDCs would therefore qualify as "Domestic electric utilities." Further, "Electric power facilities" are defined under RSA 374-A:1, III as "generating units rated 25 megawatts or above and transmission facilities rated 69 kilovolts or above planned to be placed in service in New England after June 24, 1975."

RSA 374-A:2, entitled "Powers of Domestic Electric Utilities," states: "*Notwithstanding any contrary provision of any general or special law* relating to the powers and authorities of domestic electric utilities or any limitation imposed by a corporate or municipal charter, but subject to the conditions set forth in this chapter, a domestic electric utility shall have the following additional powers:

I. To jointly or separately plan, finance, construct, operate, maintain, use, *share costs of*, own, mortgage, lease, sell, dispose of *or otherwise participate in* electric power facilities or portions thereof *within or without the state* or the product or service therefrom or securities issued in connection with the financing of electric power facilities or portions thereof; and

II. To enter into and perform contracts and agreements for such joint or separate planning, financing, construction, purchase, operation, maintenance, use, *sharing costs of*, ownership, mortgaging, leasing, sale, disposal of *or other participation in electric power facilities, or portions thereof*, or the product of service therefrom, or securities issued in connection with the financing of electric power facilities or portions thereof…." (emphasis added).

Under the plain language of RSA Chapter 374-A, it would appear that New Hampshire EDCs are granted the corporate power to share the costs of, or otherwise participate in, electric generating units rated 25 megawatts or above, or portions thereof, both inside and outside of New Hampshire. Arguably, the contracting for gas capacity from pipeline and/or LNG enterprises, on behalf of electric generators of at least 25 MW, would constitute permissible contracting under RSA 374-A:2, II for the sharing of costs of, and a form of other participation in, such electric power facilities. Furthermore, the actual transfer of such capacity rights, and the payment therefor, would arguably be allowable sharing in the costs of, or otherwise participating in, such electric power facilities under RSA 374-A:2, I. These provisions were not repealed twenty years later, with the advent of restructuring, but have rather remained as part of the statutory scheme administered by the Commission. Staff anticipates that the Commission could consider RSA Chapter 374-A as an ongoing basis for authority to act by New Hampshire EDCs, and that if the Commission initially rules that EDC participation in a gas capacity acquisition program did not violate the Restructuring Principles of RSA Chapter 374-F, RSA Chapter 374-A would grant authorization to the EDCs to enter into such activities, subject to Commission review.

As part of its analysis of RSA Chapter 374-A, Staff engaged in research at the New Hampshire State Archives regarding the 1975 legislative history in this enactment, which is scanty. Staff does note that references were made to New Hampshire EDCs (then vertically integrated) being granted authorization to participate in the New England Power Pool (NEPOOL) through the statute, which is to be expected. However, there were more general public policy considerations at work. In the words of Senator Stephen W. Smith, on May 29, 1975, "I feel that what [RSA Chapter 374-A] will do as far as the consumer is concerned is that in the long haul it is going to allow the consumer to have adequate power facilities so that we can have electricity in our homes and factories and other places. I think it is going to give the consumer the ability to have this power and in the long run at a lower rate." (N.H. Senate Journal, 29 May 75, at p. 971). Staff considers RSA Chapter 374-A's survival into the current "restructured" age to be worthy of attention, in that it potentially offers EDCs the ability to engage in creative approaches towards reducing their customers' energy costs through the acquisition of gas capacity resources, as part of the costs of electric power facilities. Within the language of RSA Chapter 374-A itself, there is no affirmative limitation on the powers enumerated to the NEPOOL context alone, and the savings clause "[n]otwithstanding any contrary provision of any general or special law…" still stands, which should be a factor for consideration by the Commission when interpreting RSA Chapter 374-A in light of the Restructuring Principles of RSA 374-F.

Though Staff is of the view that RSA Chapter 374-A provides New Hampshire EDCs with the most foursquare statutory authorization for entering into gas capacity activities, such as that is available, additional indirect statutory support may be found at RSA 374:57, titled "Purchase of Capacity." The "capacity" in question is not specified as either gas or electric capacity: "Each electric utility which enters into an agreement with a term of more than one year for the purchase of generating capacity, transmission capacity or energy shall furnish a copy of the agreement to the commission no later than the time at which the agreement is filed with the Federal Energy Regulatory Commission pursuant to the Federal Power Act or, if no such filing is required, at the time such agreement is executed. The commission may disallow, in whole or part, any amounts paid by such utility under any such agreement if it finds that the utility's decision to enter into the transaction was unreasonable and not in the public interest." RSA 374:57. It could be argued that this reporting requirement does not only pertain to electric transmission capacity arrangements by New Hampshire EDCs, but to gas transmission capacity arrangements as well, which would dovetail with the corporate powers of RSA Chapter 374-A, and establish a public interest standard for a Commission review proceeding.

Issue 3: Could New Hampshire EDCs recover the costs associated with gas capacity acquisition in rates under RSA Chapter 378 and allied statutes?

If the Commission were to rule, upon receiving an EDC proposal, that (1) participation in capacity-purchase arrangements by New Hampshire EDCs did not violate the Restructuring Principles of RSA Chapter 374-F, and (2) the corporate powers granted to EDCs by RSA Chapter 374-A did embrace such activities, and that exercise of such powers would be in the public interest per RSA 374:57, the Commission would then be left with the question of whether the costs of such programs could be recovered from

EDC ratepayers, and under what terms. RSA Chapter 374-A itself, within RSA 374-A:6, III, specifies: "In addition to ownership, sole or joint in electric power facilities, the commission shall include in the rate base of a domestic electric utility any investments, including securities, prepayments or other investments, acquired by it in connection with its participation in an electric power facility within or without the state." This provision contemplates cost recovery for investments made by New Hampshire EDCs pursuant to RSA 374-A:2 through rates, without specifying the rate category from which this recovery would be made. Arguably, a recurring expense item for gas capacity reservation by an EDC could qualify as an "investment" for inclusion in rate base in this context.

Further guidance may be found in RSA 374:2, which states: "All charges made or demanded by any public utility for any service rendered by it or to be rendered in connection therewith, shall be just and reasonable and not more than is allowed by law or by order of the public utilities commission. Every charge that is unjust or unreasonable, or in excess of that allowed by law or by order of the commission, is prohibited." RSA Chapter 378 further elaborates on the Commission's ability to adjudicate proposed rates for all utilities, and, under RSA 378:8, establishes that the burden of proof for higher rates lies with the utility petitioning for such rates.

Broad discretion is assigned to the Commission in the fixing of rates. This memorandum will not serve as a primer for utility rate regulation in New Hampshire; however, Staff has developed a framework for analyzing issues that would arise from an EDC seeking rate recovery for a gas-capacity related recurring cost or expense. Initially, though RSA 374-A:6, III does authorize the addition of qualifying EDC investments in electric power facilities into rate base, which could potentially embrace a recurring expense item for gas capacity reservation, Supreme Court precedent has held that "[p]roperty not devoted to the production and delivery of energy to the consumer is not includable in the rate base." *Legislative Utility Consumers' Council v. Public Service Co.*, 119 N.H. 332, 354 (1979). It could be argued that this principle would override the authorization of RSA 374-A:6, III for inclusion of gas-capacity related costs in rate base, in that there would be too tenuous a link between the electrical energy delivered to EDCs' customers and the gas capacity proffered to merchant generators by the EDCs. This problem would be less attenuated if an EDC were to rely on RSA 374-F:3, V(e) alternative default service provision authority, in that the EDC could more firmly argue that lower Default Service rates made possible through a gas capacity arrangement with merchant generators (through, for instance, paired energy supply contracting arrangements with merchant generators/suppliers receiving the gas capacity) would result in direct delivery of lower-cost energy to the EDC's Default Service customers, and thereby be in the public interest. This, in turn, could justify rate recovery for such a program through Default Service rates approved by the Commission, with a fairly tight nexus between the gas-capacity acquisition activities of the EDC and the energy supplied to Default Service customers.

However, an EDC seeking recovery of gas capacity acquisition costs through distribution rates (as opposed to Default Service rates) could argue that, in a seamless

ISO-New England electricity supply market, the provision of gas capacity to merchant generators in the region would still be "devoted to the production and delivery of energy to the consumer," in that all EDC distribution customers draw energy from the same collective ISO-New England system. Furthermore, such an EDC could argue that the lower electricity prices resulting from a gas-capacity acquisition program would benefit all classes of distribution customers, including those taking supply service from competitive suppliers, insofar as all EDC customers are exposed to ISO-New England prevailing market conditions to some extent. Conversely, competitive suppliers or other stakeholders could raise objections to such an approach on the basis that such intervention into ISO-New England pricing structures could impair the value of their business arrangements with their wholesale upstream suppliers and/or merchant generators, and their competitive position in the supply market generally, and thereby violate the Restructuring Principles and the "just and reasonable" standard of ratemaking. In seeking to expand the Commission's ability to develop novel ratemaking approaches to these questions, authority could be sought by an EDC under RSA 374:3-a (Alternative Regulation), which states: "Upon petition of a regulated utility or upon its own initiative and after notice and hearing, the public utilities commission may approve alternative forms of regulation other than traditional methods which are based upon cost of service, rate base and rate of return, provided that any such alternative results in just and reasonable rates and provides the utility the opportunity to realize a reasonable return on its investment."

In any event, Staff has developed the following list of preliminary criteria, subject to future expansion, for the assessment of whether a proposal by a New Hampshire EDC for the acquisition of gas capacity resources for provision to merchant generators, and recovery of related costs, would be in the public interest, and result in just and reasonable rates for approval by the Commission:

I. There must be a clear, verifiable cost-benefit advantage for EDC customers that would result from enactment of the gas capacity program. Such an advantage should be demonstrated through hard pricing data and quality studies. If the program is limited to recovery from Default Service customers (authority sought pursuant to RSA 374-F:3, V(e)), rate reductions for Default Service must be demonstrated. If rate recovery is sought from all EDC customers, through distribution rates, electricity cost savings for all customers, including those taking competitive supply, must be demonstrated.

II. In order for rate recovery to be held just and reasonable, and the program costs in rate base to be considered prudently incurred, it is imperative that EDC gas capacity-acquisition arrangements with pipeline and/or LNG counterparties be accomplished at arm's length, in compliance with affiliate transaction rules, and through RFP-based project selection processes applying least-cost and reliability criteria in EDC decision-making.

III. An EDC seeking Commission authority to engage in gas-capacity acquisition should demonstrate that such activity would not result in "re-vertical integration" of the ISO-New England wholesale electricity market, would not result in undue competitive harms to New Hampshire competitive electric suppliers, nor cause undue competitive harms to wholesale electric market participants generally. RSA 374-F:3.

IV. An EDC seeking authority to engage in such gas-capacity arrangements must demonstrate that the proposed program is unlikely to result in stranded, or deferred, costs for EDC customers.

Staff expects to provide more legal analysis of these and related matters in its September 15 Report.

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

IR 15-124

Report on Investigation into Potential Approaches to Mitigate Wholesale Electricity Prices

Prepared by:

The Staff of the New Hampshire Public Utilities Commission

September 15, 2015

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EXECUTIVE SUMMARY

In April of this year, the New Hampshire Public Utilities Commission announced in an Order of Notice the opening of a non-adjudicative investigation, to be conducted by its Staff, into potential approaches involving New Hampshire's electric distribution companies (EDCs) to mitigate the high and volatile electricity prices that have affected electricity markets in New Hampshire and other New England states in recent winters. On June 2, Staff received twenty five sets of comments from stakeholders in the investigation, some of which include detailed solutions to the high electricity price problem. Two such solutions (Access Northeast and PNGTS) propose to expand existing New England natural gas pipelines whereas a third (Northeast Energy Direct) is based on the construction of a new "greenfield" pipeline that runs through Massachusetts and New Hampshire. All three pipeline-based solutions propose to deliver significant volumes of incremental natural gas supplies to New England from the Marcellus Shale gas formation in Northeastern Pennsylvania. Another stakeholder (CLF) proposes to address the problem not by adding incremental pipeline capacity but by increasing the utilization of the region's existing LNG infrastructure, which it defines as the combination of local gas distribution company (LDC)-owned satellite liquefied natural gas (LNG) storage and vaporization facilities and LNG import terminals. Other stakeholders have suggested the introduction of a combination of energy efficiency, demand response, and distributed generation solutions, without specifying the costs and benefits of such an approach.

In addition to the above referenced comments and solutions, Staff and several stakeholders submitted memoranda addressing the legal question set forth in the Order of Notice; namely, whether New Hampshire EDCs, under existing New Hampshire law, have the authority to enter into contractual arrangements with sponsors of regional projects to acquire pipeline and/or LNG related products and services to benefit their customers and, if so, whether the associated costs can be recovered from EDC customers through Commission-approved rates.

In this executive summary we summarize our key findings regarding the legal question and the detailed solutions proposed to mitigate the high and volatile wholesale electricity prices. In brief, we view Access Northeast and Northeast Energy Direct (NED) as two very cost-effective projects that will moderate future winter electricity prices though the numbers clearly indicate that NED will provide the greatest benefits to regional electricity customers. Nonetheless, Staff's principal recommendation in this report is that if the Commission chooses to participate in a regional procurement of gas capacity (whether pipeline or LNG) for the benefit of electricity consumers it should condition that participation on the procurement being conducted through an open and transparent process that is demonstrably competitive and results in the lowest possible cost to consumers. Our key findings are as follows:

1) From a legal perspective, Staff has concluded that the Commission may hold that New Hampshire EDCs have authority to enter into gas capacity contracts for the benefit of gas-fired generators, if such a proposal were to be made by a New Hampshire EDC.

2) All three of the pipeline-based projects will enhance electric grid reliability by providing gas generators access to firm fuel supplies through the provision of firm transportation and no-notice services. The sponsors of the Access Northeast project even assert that their solution is designed first and foremost to enhance electric grid reliability rather than mitigate high and volatile electricity prices; a statement Staff finds difficult to understand given that the region already has 6,000 MW of gas generation capacity with dual-fuel capability to

protect against gas supply interruptions.[1] In addition, ISO-NE's Pay for Performance capacity market redesign, which is expected to become fully operational in June of 2018, will provide both financial incentives and penalties to existing generators to improve generator performance and to new gas generators to improve fuel assurance. For these reasons, Staff places less weight on reliability benefits and more weight on the benefits of price mitigation.

3) In a report prepared for the sponsors of the Access Northeast project, ICF International projects that under normal weather conditions and without Access Northeast January average natural gas prices will increase steadily from about $15/MMBtu in 2019 to about $23/MMBtu in 2028 due to expected growth in the demand for natural gas for heating and electric generation and decreased gas supplies from Atlantic Canada.

4) With Access Northeast but without taking into account the positive effects of reduced price volatility, ICF projects January average natural gas prices to remain at relatively high levels ranging from $12/MMBu to $20/MMBtu over the 2019 through 2028 period, a result that reflects an expectation of continued bottlenecks on the Algonquin pipeline. The $3/MMBtu reduction in average January gas prices, which together with smaller average price reductions in other months, translates to an annual average wholesale energy cost saving of $450 million over the first ten years after the project is placed in service.

5) When the effects of reduced price volatility are taken into account, ICF estimates wholesale energy cost savings to increase by an additional $330 million annually under a low price volatility scenario and by $750 million annually under a high price volatility scenario. Overall, the total annual average wholesale energy cost savings are estimated at $780 million to $1.2 billion for the low and high volatility scenarios respectively. The corresponding annual cost to achieve these savings is estimated at about $600 million.

6) Based on these savings and cost estimates, Staff estimates the benefit to cost ratio for the Access Northeast project to be in the range of 1.3 to 2.0. Further, in order to allow such a cost-effective project to proceed, we estimate that the Commission would need to approve a distribution surcharge on all New Hampshire electricity consumers of about 4.8 mills per kWh. Revenues received from the release of the pipeline capacity to gas generators or to secondary market participants could result in a lower distribution surcharge.

7) Tennessee Gas Pipeline's NED project will deliver up to 1.3 Bcf/day of firm gas supplies from Wright, New York to several existing New England pipelines in the vicinity of Dracut, Massachusetts. Upon completion of the NED project, TGPwill have the ability to physically deliver into every pipeline system serving New England as well as to incrementally serve markets along its own pipeline system. In addition, because of the location the NED pipeline relative to the Central Massachusetts Hub (Mass Hub) area, TGP could play a critical role in serving future new generation expected to be located in that area.

[1] Or 1,000 MW more than the sponsors of Access Northeast contend is needed to supply load reliably.

8) In a report prepared for TGP on the impact of the NED project on New England gas and electricity markets, ICF[2] projects that under normal weather conditions and without NED in place January average natural gas prices will increase steadily from about $15/MMBtu in 2019 to about $30/MMBtu in 2028.[3] To put these prices in context, the average Algonquin citygate price for January 2014, an extremely cold month, was about $23/MMBtu and February 2015, the coldest Febuary on record, was $17/MMBtu.

9)With NED but without taking into account the positive effects of reduced price volatility, ICF projects January average natural gas prices to range from about $10/MMBu to $18/MMBtu over the 2019 through 2028 period, equivalent to January average price reductions of $5/MMBtu to $12/MMBtu. These average price reductions when combined with smaller average price reductions in other months translates to an annual average wholesale energy cost saving of $2.1 billion over the first ten years after the project is placed in service.

10) When the effects of reduced price volatility are taken into account, ICF estimates total annual average wholesale energy cost savings for NED to range from $2.1 billion to $2.8 billion assuming zero volatility and high volatility scenarios respectively. The corresponding annual cost of the electric portion of the NED project is estimated at $400 million.

11) Based on the above savings and cost estimates, we estimate the benefit to cost ratio for the NED project to be in the range 5.25 to 7.0 not including the value of enhanced electric grid reliability and the investment cost to provide enhanced transportation services. Further, in order to allow such a cost-effective project to proceed, we estimate that the Commission would have to approve a distribution surcharge on all New Hampshire electricity consumers of about 3.3 mills per kWh. Revenues received from the release of the pipeline capacity to gas generators or to secondary market participants would further lower the distribution surcharge

12) While Staff has no reason to believe that the new pipeline expansion project proposed by Portland Natural Gas Transmission System (PNGTS) will not also enhance electric grid reliability and mitigate winter electricity price spikes, the magnitude of the potential improvements is unknown because PNGTS is in a fairly early stage of its project-development process, and has not been able to convey cost estimates as of this present time.

13) According to CLF, the most cost-effective way to address the current shortage of pipeline capacity is not to construct new or expanded pipelines from the west but to increase the utilization of the region's existing LNG infrastructure, which it defines as the combination of LDC-owned satellite LNG storage and vaporization facilities and onshore and offshore LNG import facilities. Under CLF's proposal, the LNG import facilities would be used in conjunction with expanded truck deliveries to refill the satellite LNG facilities to effectively base-load

[2] That is, the same consulting firm used by sponsors of the Access Northeast project but under a separate engagement. ICF used the same methodology for both reports.
[3] See footnote 56 for an explanation of why the ICF gas price projection in the NED report differs from the corresponding projection in the Access Northeast report.

these LDC assets. This would create, a winter-only LNG "pipeline" for LDCs to supply gas customer demands on 50 days each winter when the demand for natural gas is projected to exceed pipeline capacity with excess supply available for release to gas generators. Though Staff does not take a position on CLF's proposal at this time, we do note that ICF has recently projected that under normal weather conditions daily gas demands in 2020 will exceed daily supply capacity on 63 days and in 2035 by 113 days. Further, under design weather conditions the duration of capacity deficits is projected to increase from 78 days in 2020 to 122 days in 2035. Assuming ICF's projections to be accurate, the volume of LNG required to meet the capacity deficits (under both normal and design weather conditions) will be far greater than CLF has estimated, thus significantly reducing if not eliminating the claimed cost savings relative to pipeline capacity purchases.

14) In the event the New England states decide as a group to proceed with the procurement of incremental pipeline capacity on a regional basis, Staff strongly recommends that procurement not be based on the results of pipeline open seasons. Given that the capacity purchased by EDCs will be paid for by the customers of those companies and not by the shareholders, Staff believes that it is incumbent on regulators to ensure that the needed capacity be allocated among pipeline projects through an open and transparent process that is demonstrably competitive and results in the lowest possible cost to consumers. Because most of the largest EDCs in New England are affiliated with the sponsors of one of the competing pipeline projects, we believe it will be difficult if not impossible for EDCs to make a convincing case that pipeline open seasons qualify as fair, open and transparent competitive processes. For this reason, Staff believes it is imperative that the states develop and post for comment an alternative competitive solicitation process (i.e., a Request for Proposals). In Staff's opinion, the terms and conditions for a gas capacity RFP including the criteria for bid evaluation should be the responsibility of the states assisted by an independent consulting firm with extensive expertise in gas and electricity procurement matters.

Absent a demonstrably competitive solicitation, Staff foresees a significant risk that the negotiations between a project sponsor and potential customers will not be at arms-length and thus will not produce the most advantageous cost and commercial terms for consumers. We also foresee the prospect of lengthy and costly delays due to litigation initiated by aggrieved project sponsors.

INTRODUCTION

On April 17, 2015, the New Hampshire Public Utilities Commission (Commission) announced in an Order of Notice (Order) the opening of a non-adjudicative investigation, to be conducted by its Staff, into potential approaches involving New Hampshire's electric distribution companies (EDCs) to mitigate the high and volatile winter electricity prices affecting electricity markets in New Hampshire and other New England states.[4] As noted in the Order, competition in wholesale and retail electricity markets had, until recently, kept electricity prices at reasonable levels for New Hampshire consumers. The past two winters, however, have seen significant changes in New Hampshire's wholesale and retail electricity markets, and those of the New England region generally; changes that some have attributed to the increasing dependence on natural gas generation plants to supply the region's electricity requirements.

On May 12, 2015, Staff met informally with interested stakeholders regarding its investigation and invited them to propose specific detailed solutions to the problem, no later than June 2, 2015. Detailed guidance on the content of submissions including commercial and analytical data was communicated to stakeholders through a May 14 letter from Staff, a copy of which was placed on a public website created especially for the investigation. In addition, written comments that do not offer specific solutions but instead provide advice on how the state and the region should address the winter price problem were welcomed. Staff also advised that it could issue written questions to stakeholders that make submissions, and also potentially schedule bilateral meetings with certain stakeholders. Staff questions and stakeholder responses were also placed on the public website.

On June 2, 2015, Staff received twenty five submissions including two solutions that propose the expansion of existing New England natural gas pipelines and one solution that is based on the construction of a new "greenfield" natural gas pipeline that runs through Massachusetts and New Hampshire. All three pipeline-based solutions propose to deliver to New England significant volumes of incremental natural gas supplies from the Marcellus Shale deposit in Pennsylvania. In addition, two stakeholders proposed that the problem be solved through the use of existing or new LNG storage facilities located within New England. Others have proposed to address the problem through a combination of expanded energy efficiency programs, increased importation of Canadian hydroelectricity and increased development of renewable resources. All submissions are available for public inspection on the Commission's website, as are Staff's written questions and stakeholder responses, here:
http://www.puc.nh.gov/Electric/Investigation_into_Potential_Approaches_to_Mitigate_Wholesale_Electricity_Prices.html.

During the course of our investigation, we conducted a number of interviews with nine stakeholders to better understand how the proposed solutions will work in practice including obtaining better information on the potential costs and benefits of each project.

In addition, Staff and several stakeholders submitted memoranda addressing the legal question set forth in the Order; namely, whether New Hampshire EDCs, under existing New Hampshire law, have the authority to enter into contractual arrangements with project sponsors to acquire pipeline and/or LNG-

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[4] Staff's investigation is limited to issues relating to the high and volatile electricity prices that have affected regional electricity markets over the past few winters and therefore does not address other important issues like project siting and the impacts to the environment and landowners that are the responsibility of other state and federal agencies.

related capacity to benefit their customers and, if so, whether the associated costs can be recovered from EDC customers through Commission-approved rates. Staff also hereby requests that the Commission grant leave for stakeholders to file comments with the Commission on Staff's report, which summarizes the investigation and the findings based on that investigation. Staff suggests that stakeholders be given one month after the filing of our report, until October 15, 2015, to submit their comments.

LEGAL ANALYSIS OF EDC AUTHORITY TO ENTER INTO PIPELINE CAPACITY CONTRACTS

As an initial matter, Staff wishes to clarify that in its analyses of the legal questions related to potential acquisition of gas infrastructure capacity by New Hampshire EDCs, Staff is not proposing any solution to the Commission. In actuality, Staff is analyzing the potential solutions that have been proffered by certain stakeholders. Therefore, characterizing Staff's discussion of such potential solutions in the context of this Investigation as a "Staff proposal," or a "proposal favored by Staff"[5] is not adequately precise, nor is it accurate.

Staff engaged in an initial discussion of legal issues related to this Investigation in a memorandum dated July 10, 2015 (July 10 Memorandum), which was made available to stakeholders and the public via the NHPUC website.[6] In response, several stakeholders (the Conservation Law Foundation (CLF)[7], the Office of the Consumer Advocate (OCA)[8], Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource)[9], Algonquin Gas Transmission, LLC/Spectra Energy Partners, LP (Spectra)[10], Tennessee Gas Pipeline Company, L.L.C (TGP)[11], the New England Power Generators Association, Inc. (NEPGA)[12], and the Coalition to Lower Energy Costs (CLEC)[13]) issued responses to the July 10 Memorandum on August 10, 2015. These responses presented a wide diversity of views regarding the potential legality of New

[5] *See* OCA Response to Staff, August 10, 2015 at p. 2.
[6] *See* Memorandum of Alexander Speidel to George McCluskey, July 10, 2015, at http://www.puc.nh.gov/Electric/Wholesale%20Investigation/20150710%20IR%2015-124%20Staff%20Legal%20Memorandum%20on%20Authorities%207-10-15.pdf
[7] CLF August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/2015-08-10%20CLF%20Comments%20on%20Staff%20Legal%20Memorandum.pdf
[8] OCA August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/OCA%20Comments%20re%20Staff%20Memo%208-10-15.pdf
[9] Eversource August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Cover%20Letter%20to%20August%2010%20Reply%20Comments.pdf
[10] Spectra August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Spectra%20Energy%20comments%20on%20Staff%20Legal%20Memorandum%2015-124%20(3).pdf
[11] TGP August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Comments%20of%20TN%20Gas%20Pipeline%20Co.%20on%20Staff%20Legal%20Memo%208-10-15.PDF
[12] NEPGA August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/NEPGA%20Comments%20to%20Staff's%207-10-15%20Memo%20IR%2015-124%20(8-10-15).pdf
[13] CLEC August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Comments%20of%20CLEC%20to%20Staff%20Memo%208_10_15.PDF

Hampshire EDCs acquiring gas pipeline capacity for the ultimate use of gas generators. Having reviewed the responses of these stakeholders, and having considered the matter further, Staff re-adopts the conclusions of the July 10 Memorandum, with the following expansions and clarifications.

On the question of whether the New Hampshire Electric Restructuring Statute (RSA Chapter 374-F) allows or prohibits New Hampshire EDCs to engage in such activities:

In their responses to the July 10 Memorandum, certain stakeholders supported the proposition that RSA Chapter 374-F allows for the acquisition of pipeline capacity by New Hampshire EDCs (CLEC, Eversource, Spectra, TGP), and others (CLF, NEPGA, OCA) opposed this proposition. In its July 10 Memorandum, Staff indicated that the Commission could conceivably hold that RSA 374-F allows such activity by EDCs. Staff re-affirms this position.

In Staff's view, the Commission could determine that the Restructuring Policy Principle delineated in RSA 374-F:3, III, regarding the functional separation of generation services from transmission and distribution services, could be complied with by an EDC acquiring gas capacity on behalf of merchant generators, insofar as separate ownership of the actual generation plants will remain in the hands of merchant generation companies, rather than the EDCs. The Commission could therefore find that an adequate level of "functional separation" for the purposes of RSA 374: F-3, III is thereby maintained.

Furthermore, Staff continues to recognize that the Commission could reasonably find that the functional-separation principle of RSA 374: F-3, III should be read in concert with the other Restructuring Policy principles of RSA Chapter 374-F. RSA 374-F: 3, I states: "Reliable electricity service must be maintained while ensuring public health, safety, and quality of life." RSA 374-F: 3, VI: "A nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system may be used to fund public benefits related to the provision of electricity. Such benefits, as approved by regulators, may include, *but not necessarily be limited to*, programs for low-income customers, energy efficiency programs, funding for the electric utility industry's share of commission expenses pursuant to RSA 363-A, support for research and development, and investment in commercialization strategies for new and beneficial technologies" (emphasis added). RSA 374-F: 3, XII: "New Hampshire should work with other New England and northeastern states to accomplish the goals of restructuring. Working with other regional states, New Hampshire should assert maximum state authority over the entire electric industry restructuring process." RSA 374-F: 3, VIII: "Continued environmental protection and long term environmental sustainability should be encouraged....As generation becomes deregulated, innovative market-driven approaches are preferred to regulatory controls to reduce adverse environmental impacts."

Staff considers these other Restructuring Policy Principles to be of similar importance to the functional separation principle, and therefore, Staff believes that the Commission could rule, in response to a proposal being made by a New Hampshire EDC, that the potential benefits of a gas-capacity acquisition project would foster the overall goals of the Restructuring Policy Principles of RSA 374-F. These goals include, but are not limited to: cost savings for distribution customers of EDCs; enhanced reliability for New England's increasingly gas-dependent electric generation fleet and electric transmission system; and environmental benefits from the displacement of inefficient coal and oil generation units by highly efficient gas generation units. Staff believes that quality evidence of such benefits will be of critical importance in gauging the appropriateness of a given proposal under RSA 374-F.

On the question of statutory/corporate authority for New Hampshire EDCs to engage in such activities:

In its July 10 Memorandum, Staff indicated that RSA Chapter 374-A offered the most foursquare authorization for New Hampshire EDCs to acquire gas pipeline capacity on behalf of merchant generators. In response, Eversource stated that RSA Chapter 374-A "is not directly applicable to the potential solution described by Eversource."[14] Instead, Eversource pointed to RSA 374:57, relating to the "Purchase of Capacity" as the "most appropriate" basis for potential Commission review of Eversource's proposal.[15] CLEC stated, in its August 10 response, that "there is no need to find specific language in NH law authorizing EDCs to purchase pipeline capacity," as the general corporate powers delineated in RSA Chapter 295 granted such authority.[16] TGP concurred generally with Staff's analysis of RSA 374-A in its August 10 response, while CLF and NEPGA directly opposed Staff's conclusion regarding RSA 374-A.[17]

Staff re-affirms its July 10 Memorandum analysis of RSA Chapter 374-A. Staff does note, however, that the New Hampshire EDC most likely to submit an actual proposal for Commission review, Eversource, has indicated that it would likely rely upon RSA 374:57, not Chapter 374-A, as its primary statutory authority in its proposal. In its July 10 Memorandum, Staff characterized the 374:57 statute as providing "additional indirect statutory support."[18] Staff views the applicability of RSA 374:57 to gas capacity acquisitions, in addition to electric capacity acquisitions, to be the key question for Commission resolution regarding the applicability of this statute to the activities being proposed by Eversource. Given that the plain language of the statute does not specify the type of capacity (the term "capacity" being in common use in both the gas and electric industries), the Commission could rule that gas capacity purchases were contemplated by RSA 374:57, and therefore allowed.

Staff also takes note of the disallowance and public-interest review standards of RSA 374:57 ("The commission may disallow, in whole or part, any amounts paid by such utility under any such agreement if it finds that the utility's decision to enter into the transaction was unreasonable and not in the public interest"), to which the following criteria (delineated in the July 10 Memorandum) should be applied by the Commission: (1) There must be a clear, verifiable cost-benefit advantage for EDC customers that would result from enactment of the gas capacity program. Such an advantage should be demonstrated through hard pricing data and quality studies. If the program is limited to recovery from Default Service customers (authority sought pursuant to RSA 374-F:3, V(e)), rate reductions for Default Service must be demonstrated. If rate recovery is sought from all EDC customers, through distribution rates, electricity cost savings for all customers, including those taking competitive supply, must be demonstrated; (2) in order for rate recovery to be held just and reasonable, and the program costs in rates to be considered prudently incurred, it is imperative that EDC gas capacity-acquisition arrangements with pipeline and/or LNG counterparties be accomplished at arm's length, in compliance with affiliate transaction rules, and through RFP-based project selection processes applying least-cost and reliability criteria in EDC decision-making; (3) an EDC seeking Commission authority to engage in gas-capacity acquisition should demonstrate that such activity would not result in "re-vertical integration" of the ISO-New England wholesale electricity market, would not result in undue competitive harms to New Hampshire

[14] Eversource August 10 Response at p. 11.
[15] Eversource August 10 Response at pp. 11-14.
[16] CLEC August 10 Response at pp. 2-6.
[17] *See* TGP, CLF, and NEPGA August 10 Responses.
[18] July 10 Memorandum at 5.

competitive electric suppliers, nor impair the ability of the Commission to manage New Hampshire's competitive electric and gas markets; (4) an EDC seeking authority to engage in such gas-capacity arrangements must demonstrate that the proposed program will not result in stranded, or deferred, costs for EDC customers.

On the question of cost recovery for such EDC investments:

In its August 10 response, Eversource indicated that it would not seek to place its proposed investments of gas capacity, made pursuant to RSA 374:57, into its EDC rate base.[19] Eversource generally indicated that "[s]imilar to the manner in which power purchase agreements ('PPAs') have been handled in New Hampshire, the expenses of the [gas capacity] contract would be reduced by the revenues generated when the capacity was released and sold, and the resulting amounts would either be credited to, or recovered from, customers from their rates. It would not be an item in the EDC's rate base subject to traditional cost-of-service ratemaking."[20]

Staff points to RSA 378:8, which establishes the general principle that a utility seeking higher rates bears the burden of proving the necessity of the increase. Staff would expect the Commission to apply the traditional ratemaking criteria of least-cost procurement, prudency, and allocation fairness to any surcharge sought by an EDC for gas capacity activities, and that any surcharge should be justified by a proposing EDC under a specific statutory provision, or provisions, of New Hampshire law.

On the need for competitive bidding for pipeline capacity:

Staff, in its July 10 Memorandum, strongly advocated for the requirement that New Hampshire EDCs seeking to acquire gas pipeline capacity do so through a competitive bidding (Request for Proposals, or RFP) process, in which different pipeline companies would compete for the EDCs' contracts.[21] Staff also pointed to the need by EDCs to maintain compliance with affiliate transaction rules within any gas-capacity acquisition program, an issue also discussed by NEPGA in its August 10 response.[22] Staff reiterates, in the strongest terms, that Staff views RFP-based competitive processes to be critical to the economic procurement of gas capacity at the lowest cost by EDCs from pipeline developers, and Staff will not support any EDC proposal that fails to incorporate such a competitive process in its capacity procurement structure. Staff strongly disagrees with Spectra's conclusion that there is an "absence of a legal mandate for an RFP"[23]; such processes are critical for protecting ratepayer interests, and ensuring that cost recovery of such investments are just, reasonable, and in the public interest.

On federal preemption, and litigation risk generally:

Staff acknowledges that the role of the states in overseeing wholesale electricity and gas markets, in parallel with the primary jurisdiction of the Federal Energy Regulatory Commission (FERC), is currently in flux, and subject to challenge. A minimalist position, shared by some industry advocates and others, has developed which holds that states cannot act directly in shaping wholesale market outcomes through mandatory procurement programs, nor can states even approve, through their regulatory bodies'

[19] Eversource August 10 Response at pp. 14-15.
[20] Eversource August 10 Response at p. 15.
[21] July 10 Memorandum at p. 7.
[22] NEPGA August 10 Response at p. 11.
[23] Spectra August 10 Response at p. 7.

adjudicative processes, initiatives which could impact prevailing wholesale market prices and/or competitive conditions. This minimalist position, which fundamentally rejects any "dual responsibility" by both the FERC and states in wholesale market oversight, has been bolstered by recent (2014) decisions by the Third and Fourth Circuit U.S. Courts of Appeals in the *PPL EnergyPlus, LLC* cases, regarding New Jersey and Maryland mandates and incentives for specific generation-resource siting. These decisions, upholding the U.S. District Courts' decisions to strike down the state programs under the Supremacy Clause of the U.S. Constitution, on the basis that the states' incentive programs for generation violated FERC's jurisdiction over wholesale transactions and rate-setting under the Federal Power Act, were very broad in their language, implying that states' wholesale market activities would be subject to close judicial scrutiny going forward.[24] (Maryland and New Jersey have each sought Writs of Certiorari from the U.S. Supreme Court regarding the Circuit Courts' decisions, and similar litigation is pending before U.S. District Courts in Connecticut and Rhode Island).

Staff recognizes that state programs <u>mandating</u> acquisition of gas capacity by EDCs could face challenge under the *PPL EnergyPlus* line of reasoning. However, Staff does not share the view that a Commission adjudication, approving the <u>elective</u> acquisition of gas capacity by EDCs, would somehow trigger Supremacy Clause preemption. If the proposition that no Commission action that had an "impact" on wholesale electric and/or gas rates was allowed under the Federal Power Act or Natural Gas Act were to stand, many routine Commission approval processes (such as acceptances of precedent agreements by New Hampshire gas LDCs) could be purportedly disallowed as "preempted." Staff rejects this approach, and believes that Commission approval of a procurement investment decision by a market participant subject to its jurisdiction, that is, a New Hampshire EDC, does not run afoul of federal preemption.

Staff cannot predict how FERC would approach an innovative program such as that proposed by Eversource under the Federal Power Act and the Natural Gas Act. FERC could accept this program as a timely solution to gas-electric coordination problems, or it could reject it as unacceptable under principles such as FERC's "open-access" gas capacity allocation structure established pursuant to the Natural Gas Act and FERC precedent. Staff would expect that any Commission approval for a New Hampshire EDC would be subject to a condition of FERC/federal approval of the program.

That said, it can be expected that vigorous litigation, within and beyond the Commission, would arise from any Commission review of an EDC proposal to acquire gas capacity for the ultimate use of merchant generators. CLF, NEPGA, and OCA were clear in their August 10 responses that they did not see any legal basis for Commission action to approve such activities, or to grant rate recovery for such activities, and other stakeholders have expressed their dismay with the prospects of such a program. At every decision point, parties could challenge Commission determinations in either direction, and Staff does not expect that an approval process would prove to be as abbreviated as certain stakeholders expect (e.g., Spectra: "Spectra Energy recommends that the Commission accepts EDC contracts for filing so that review and approval may be obtained no later than the end of this calendar year.")[25]

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[24] Fourth Circuit Decision (re: Maryland), dated June 12, 2014, available at:
https://statepowerproject.files.wordpress.com/2014/03/4th-cir-opinion-060214.pdf ;
Third Circuit Decision (re: New Jersey), dated September 11, 2014, available at:
https://statepowerproject.files.wordpress.com/2014/03/3rd-cir-nj-decision.pdf

[25] Spectra August 10 Response at p. 7.

THE CAUSE OF HIGH AND VOLATILE ELECTRICITY PRICES

The May 14 guidance issued by Staff on the content of submissions began by inviting stakeholders to identify the root cause of the high and volatile winter period wholesale and/or retail electricity prices. Almost all of the stakeholders that addressed this issue directly expressed the opinion that cause of the problem can be attributed to a wholesale market imbalance of supply and demand for natural gas. Eversource, for example, asserted that this issue has been extensively studied in the last few years, with the studies reaching the almost universal conclusion that increased reliance on natural gas as a fuel for electric generation without a corresponding expansion of natural gas capacity resources into New England leads to pipeline constraints during the winter months and in turn high and volatile wholesale gas and electricity prices. Elimination of these pipeline constraints will require, according to Eversource, the construction of incremental pipeline capacity resources "as no other comparable resource is reasonably available in an adequate quantity to alleviate the supply and demand imbalance in the wholesale electricity market."

Spectra agreed that the lack of adequate natural gas pipeline infrastructure to supply regional electric generation is the primary cause of the high gas and electricity prices and, moreover, of diminished electric reliability in New England. The reason for the high prices, according to Spectra, is that the increased utilization of natural gas for home and commercial heating, industrial uses and electric generation has made the demand for firm interstate pipeline capacity in New England extremely competitive. This increasing demand has placed additional burdens on an infrastructure that was already constrained resulting in natural gas and electricity prices that are higher in New England than in markets elsewhere in North America.

CLEC noted that the Low Demand Study prepared for the Massachusetts Department of Energy Resources in early 2015, which took into account all technologically and economically feasible alternative energy resources, concluded that "[i]nsufficient natural gas capacity for the electric sector has contributed to high wholesale gas prices to generators and thus high electricity prices."

Even CLF, which appears to question in its comments whether the region actually has a high winter period electricity price problem, says in a report submitted on its half that the dramatic gas and electricity price spikes of winter 2013/14 were the result of not enough natural gas to meet demand.

Only one stakeholder, Ms. Martin, appears to question that the cause of the high price problem rests with natural gas supply winter shortages. Ms. Martin argues that the EIA electric price data cited in the Order relate to early 2015 and therefore takes no account of the lower rates in effect during the second half of the year. According to Ms. Martin, all New Hampshire utilities announced significant default service rate reductions for the second half of 2015. Averaged over the course of the year, New Hampshire electric bills have not risen dramatically above the bills paid in previous years.

Ms. Martin also argues that customers do not pay rates, but rather bills based on usage, and New England and New Hampshire customers use less electricity than most regions and states. In the case of New Hampshire residential households, Ms. Martin argues that the most recent full year price data, from 2014, when combined with the most recent average usage data, from 2013, show that New Hampshire residential electric bills were 29th highest in the United States and the District of Columbia, below the national average. Residential bills in New England overall were very consistent with the national average, and less than in the regions often cited for lower energy costs such as the South and the Middle Atlantic.

The May 14 guidance then invited stakeholders to propose solutions to the high electricity price problem and to explain in detail how the solutions would reduce prices at the wholesale and/or retail levels. Each of these project proposals are described below beginning with the Access Northeast project. These are followed by brief summaries of comments from stakeholders that do not offer specific solutions.

ACCESS NORTHEAST

Project Overview

Spectra, Eversource and National Grid, the joint owners of the Access Northeast project, have submitted a solution that they contend is designed first and foremost to enhance electric grid reliability through the provision of a new Energy Reliability Service (ERS) tariff for firm transportation customers that depends in part on the supply of natural gas from new LNG storage facilities.[26] The key features of the ERS are described below. In addition to enhancing electric grid reliability, the sponsors assert that Access Northeast will mitigate the expected future high and volatile winter period gas and electricity prices.[27]

The Access Northeast project will provide incremental firm transportation service to gas generators through a 0.5 billion cubic feet per day (Bcf/day) expansion of the existing Algonquin and Maritimes pipelines largely through the use of the "lift and lay" method, which requires the removal of smaller diameter pipe and its replacement with larger diameter pipe in the existing pipeline right of way. The expansion will also include looping in areas where extra capacity is needed.[28] As noted, Access Northeast also includes new LNG storage facilities with a combined usable capacity of 6.0 Bcf, which when combined with liquefaction and vaporization equipment will deliver up to 0.4 Bcf /day of gas on peak winter days.

Together these facilities will provide <u>up to</u> 0.9 Bcf/day of incremental capacity, sufficient according to the sponsors to supply approximately 5,000 MW of generating capacity.[29] According to the sponsors, 5,000 MW is the amount of gas-fired generation capacity that must have firm fuel supplies on peak winter days in order for load to be served reliably.[30] Although Access Northeast has been marketed to electric (rather than gas) distribution companies, one of the sponsors has been quoted as saying that the project has received interest from both EDCs and LDCs and that negotiations on long-term contracts with both have begun. Staff understands that any long term commitments with LDCs will be met from an expansion of the project above the 0.9 Bcf/day level. The proposed in-service date for the project is November 1, 2018.

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[26] Spectra owns the Algonquin pipeline and is the majority owner of the Maritimes pipeline.
[27] See Spectra Response to Initial Staff Question 5, July 6, 2015.
[28] Looping is the addition of a parallel pipe laid next to a segment of the existing pipeline. Since Access Northeast has yet to announce the project route, the location and extent of these parallel pipelines is currently unknown.
[29] Staff questions the claim that the project can supply 5,000 MW of generating capacity. While the claim would be accurate if the project was a pipeline expansion of 0.9 Bcf/day, the fact that it comprises a storage element limits its continuous supply capability. ICF modeled Access Northeast as project capable of providing 0.6 Bcf/day capacity, which would be capable of supplying between 3,100 MW and 3,500 MW depending on heat rate.
[30] A 2014 ICF International study for ISO-NE indicates a need for up to 1.1 Bcf/d of additional gas supply by 2020 to meet projected power plant fuel requirements on a design day. This, according to ICF, equates to roughly 5,700 MW of capacity.

Figure 1: Algonquin and Maritimes & Northeast Pipelines

Energy Reliability Service

The Energy Reliability Service (ERS) tariff is designed to work in tandem with incremental pipeline capacity to provide the flexibility gas generators need to accommodate large swings in electrical load and hence gas demand. ERS will be available as part of the integrated transportation/storage service provided by the Algonquin and Maritimes pipelines (see below under Firm Transportation Service). ERS is designed to provide two complimentary features that the sponsors claim are highly valued by the gas generation market.

The first feature is the reservation of pipeline transportation capacity. Under the current nomination and scheduling rules for requesting space on natural gas pipeline, a generator must comply with specific timelines established by the natural gas industry. At the timely nomination cycle, which ends 11:30 am Central Clock Time (CCT) on the day before gas flows at 9:00 am CCT, generators nominate their specific transportation capacity requirements. Pipelines evaluate those requirements in aggregate and schedule their pipelines based on the priority of services nominated. If there are potential choke points on a particular pipeline or, as is the case with Algonquin, the pipeline is fully subscribed, a particular transportation request may not be scheduled at the timely cycle or any subsequent nomination cycle that has been established. Under the ERS, the primary firm transportation capacity procured by an EDC and transferred to gas generators is reserved so that it can be nominated at the timely cycle or any subsequent nomination cycle. In essence, the primary firm transportation capacity will be available to be nominated 24/7 and, as long as gas supply is confirmed, gas deliveries can be ramped up or down based on the expected generator loads.

The second feature of ERS is the ability of a generator to ramp up its electrical output on short notice: commonly referred to as the "quick start" feature. With the transportation space already reserved on the pipeline, this quick start feature allows the generator to start flowing gas before it has submitted a nomination or has had a nomination confirmed. A generator simply has to notify Algonquin or Maritimes that it will be using the ERS before taking gas off the pipeline. The ERS allows the generator to take gas for up to two hours without having a nomination confirmed by the pipeline. This is referred to as no-notice firm transportation service. The source of this no-notice gas supply will be a combination of pipeline line pack and LNG storage withdrawals.

LNG Storage Facilities

As noted, the LNG component of Access Northeast is designed to meet the large fluctuations in demand that generators experience on a daily basis. At the present time, the sponsors contemplate that domestically sourced natural gas will be placed into storage during off-peak periods (typically, spring, summer and fall) at a cost equal to the sum of the price of gas at the receipt point where it is purchased,[31] the variable cost of transportation to the LNG storage facility, the variable cost of liquefaction, and the variable cost of storage. On peak demand days during the winter or during operating reserve deficiencies, the stored LNG would be vaporized and released to generators first and foremost at the daily spot price of natural gas in New England on the day of delivery. Any positive margin between the selling price of natural gas and the actual delivered cost of LNG to generators (i.e., cost in storage plus the variable costs of vaporization and transportation to generator delivery meters) would be credited to EDC customers.

In the event of negative margins, the sponsors contend that the Capacity Manager would likely decide not to sell gas and instead hold on to it until such time as either the market price appreciates enough to sell gas at a positive margin or the supply is needed for reliability purposes. If the negative margin scenario were to occur, sponsors argue that power prices which have typically tracked gas prices will be lower and electric customers would realize the benefit of lower electricity prices. Taken to its logical conclusion, this argument suggests that if the variable costs of LNG turn out to be higher in most hours than the spot price of gas and LNG remains in storage, Access Northeast will be incapable of fulfilling one of its primary design objectives, which is to address the unique requirements of gas generators.

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[31] The gas may be purchased inside New England at spot market prices or outside New England and transported to the region at an appropriate firm or interruptible transportation rate. Optional natural gas receipt points for Access Northeast are Brookfield, Connecticut, Mahwah, New Jersey , Ramapo, New York and Wright, New York. These receipt points connect with the following upstream pipelines: TGP, Millennium and Iroquois. See Figure 1 above.

In addition, Staff does not understand the sponsors' argument that the project was conceived with the primary goal of enhancing electric grid reliability by providing fuel assurance to gas generators. As Spectra itself acknowledges, the regional power system already has 6,000 MW of gas-fired generation with dual-fuel capability to protect against gas supply interruptions, or 1,000 MW more than Spectra contends is needed to supply load reliably. In addition, ISO-NE's Pay-for-Performance capacity market redesign, which is expected to become fully operational in June of 2018, will provide both financial incentives and penalties to existing generators to improve generator performance during times of system emergencies and new generators to acquire dual-fuel capability. To be clear, Staff is not suggesting that construction of the Access Northeast project, or for that matter the NED and PNGTS projects, will not enhance reliability. They will. Rather, we question Access Northeast's focus on system reliability at a time when ISO-NE has only recently received FERC approval of its Pay-for-Performance program, which was designed to address among other things the reliability risks associated with New England's growing dependence on natural gas and attendant vulnerability to interruptions in gas supply. The Pay-fo-Performance program will provide strong incentives for the installation and operation of dual-fuel capable generation to improve gas generator performance – if a dual-fuel generator cannot get natural gas (or if the price of natural gas is too high), the generator can instead use fuel oil or LNG as back-up fuel sources to meet its capacity obligations.[32] While the resulting increase in dependence on back-up fuel for generation can also present reliability risks, as demonstrated by the difficulties of replenishing oil supplies in winter 2013/14, Staff believes the system of incentives and penalties that constitute the Pay for Performance capacity market redesign will compel dual-fuel generators to address these risks through appropriate fuel supply planning.

Power Producer Aggregation Areas

Under the Access Northeast proposal, gas will be delivered via transportation on a primary firm basis to four Power Producer Aggregation Areas (PPAAs) as depicted in Figure 2 below. These are geographical areas that include 9,200 MW of existing gas generation capacity[33] directly or indirectly served by the Algonquin and Maritimes pipelines, which according to Spectra is equivalent to 60% of all natural-gas fired generation in New England.[34] These four areas include Connecticut, Massachusetts, Maine, and the G System on the Algonquin pipeline system. The G System is a segment of the Algonquin pipeline system from Mendon to Bourne in Massachusetts that is often fully utilized throughout the heating season. The upgraded facilities that comprise the Access Northeast project have been designed to provide all gas generators within a specific PPAA the opportunity to receive firm transportation service. However, the capacity of the generators that will actually receive such firm service in a specific PPAA will be limited by that PPAA's sub-total capacity as shown in Figure 2. As can be seen, the sub-totals sum to 5,000 MW, the amount of generation capacity the sponsors claim will be supplied by the Access Northeast project.

[32] These incentives already appear to be producing the intended market response, as evidenced by NEPGA's comments which state that six gas-fired units have committed to install dual-fuel capability including four totaling 1,039 MW in winter 2014/15 and two next winter for an additional 735 MW. In addition, two new dual-fuel units totaling 920 MW cleared the ninth FCA in February 2015.
[33] 6,900 MW is directly connected to Algonquin and the remaining 2,300 MW to Maritimes.
[34] The inference that the Algonquin/Maritimes system plays a greater role than the TGP system in meeting the needs of New England's gas generation market is disputed later in this report.

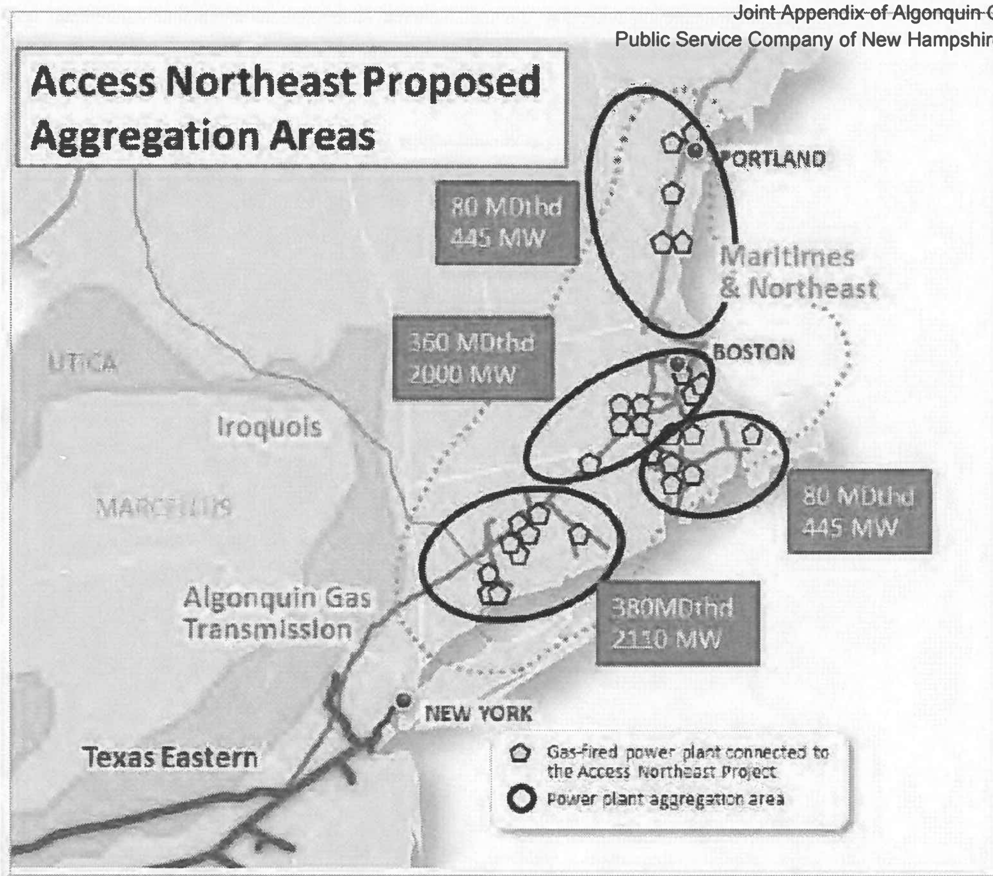

Figure 2: Access Northeast Proposed Aggregation Areas

Firm Transportation Service

Pipeline transportation service and LNG storage service will be offered as an integrated service under the Access Northeast project. Also, the Access Northeast rate for this integrated firm transportation service will be a "postage stamp" rate that applies to all generators regardless of Power Plant Aggregation Area and will cover all costs of providing transportation directly to generators including so-called "last mile" costs. The postage stamp rates will also apply to any LDC that elects to procure firm transportation service under the project.

Reliability Benefits and Energy Cost Savings

A. Reliability Benefits

As noted, the sponsors of Access Northeast view the project principally in terms of its ability to enhance grid reliability by increasing the deliverability of natural gas to electric generators. Reducing or eliminating winter period natural gas and electricity price spikes is considered to be a secondary benefit of the project.

The project sponsors assert that reliability will be improved in three ways. First, gas generators will be given the opportunity to enhance natural gas deliverability by allowing them to make firm transportation arrangements. Second, gas generators that have executed firm transportation arrangements will be given the flexibility to increase or decrease gas supplies in order to accommodate large swings in electrical load. As explained above, this will be achieved through the provision of a "no-notice" transportation service, which among other things allows gas generators to commence delivery of gas supplies to their facilities for a period of time not to exceed two hours prior to submitting a formal request for transportation space on the pipeline to deliver gas between receipt and delivery points – a process known as nomination. The importance of this "no-notice" service is that it ensures the generator is able to immediately come online when dispatched by ISO-NE. Third, the sponsors assert that the Access Northeast project has been sized to provide approximately 5,000 MW of generation capacity with firm transportation service, which is close to the amount of generation capacity that studies indicate need firm gas supplies in order to maintain power system reliability under extreme weather conditions.

B. Energy Benefits

In support of its contention that the Access Northeast project will also bring substantial economic benefits to the region, Spectra attached to its comments a February 2015 study by ICF International prepared for Eversource and Spectra of the potential impacts of the project on New England gas and electricity prices under both normal and abnormal weather conditions.[35]

(i) Normal Weather Analysis

There are two components to ICF's normal weather analysis: one that excludes the impact of reduced price volatility and the other that includes it. As can be seen in Figure 3 below, which is a plot of average monthly Algonquin citygate gas prices with and without Access Northeast but excluding the effects of price volatility, ICF projects January average natural gas prices without Access Northeast to increase steadily from about $15/MMBtu in 2019 to about $23/MMBtu in 2028 due to expected growth in the demand for natural gas for heating and electric generation and decreased gas supplies from Atlantic Canada. That is, without additional pipeline capacity in the region, the growth in the demand for gas is expected to drive up the spot market price of natural gas. Note also that over the four year period 2016 through 2019, January average prices are projected to decline due to the effects of the AIM, TGP Connecticut Expansion, and Atlantic Bridge pipeline expansion projects. In other words, ICF expects the decline in prices caused by these expansion projects to be slowed and eventually reversed by the growth in the demand for natural gas.

With Access Northeast, January average natural gas prices are projected to remain at relatively high levels ranging from $12/MMBu to $20/MMBtu over the 2019 through 2028 period, suggesting that Algonquin citygate prices will continue to reflect high basis differentials if no further pipeline capacity investments are made. According to ICF, these high citygate prices are not the result of winter price spikes on upstream pipelines feeding the Algonquin system. On the contrary, ICF's modeling assumes existing constraints on upstream pipelines will be resolved over time with investments in new pipeline capacity expansion projects. The high Algonquin citygate prices are a reflection of continued bottlenecks on the Algonquin pipeline.

Under the with Access Northeast scenario, ICF assumes the project will add 0.6 Bcf/day of incremental capacity comprising 0.5 Bcf/day of new pipeline capacity and 0.1 Bcf/day of LNG storage capacity.[36] The incremental capacity reduces January gas prices by about $3/MMBtu on average, which together with even smaller average price reductions in other months translates to an annual average wholesale energy

[35] Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England, ICF International, February 18, 2015.
[36] The assumed incremental LNG capacity is less than 0.4 Bcf/day because the stored LNG must be managed judiciously given that abnormal weather conditions can occur at any time during the coldest winter months.

cost saving of $450 million over the first ten years after the the project is placed in service. It must be emphasized, however, that the changes in natural gas and electricity prices summarized above do not take into account the effect of reduced price volatility benefits.

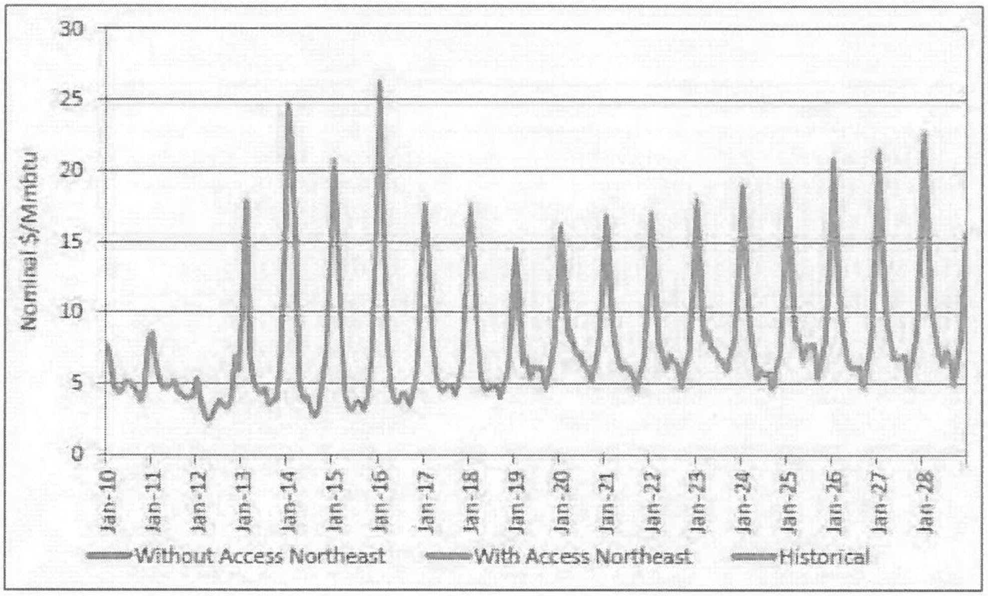

Figure 3: ICF's natural gas price forecast for New England (excluding volatility reduction benefits)

In addition to the above described average annual energy cost savings, ICF asserts that the project will produce other energy cost savings that relate to reductions in daily natural gas price volatility, i.e., reductions in the frequency and magnitude of daily gas price spikes. For this analysis, ICF analyzed two volatility reduction levels: low and high. Under the low volatility analysis, ICF assumed that the frequency and size of price spikes would be reduced by half from a moderate volatility level similar to that experienced in the 2010/11 or 2012/13 winter. This analysis resulted in an additional $330 million in annual average wholesale energy cost savings over the first ten years of the project. In contrast, the high volatility analysis, which was based on a high volatility level similar to that experienced in the 2013/14 winter, produced an additional $750 million in annual average wholesale energy cost savings. Overall, the total annual average wholesale energy cost savings is $780 million to $1.2 billion for the low and high volatility scenarios respectively.[37]

Regrettably, the ICF report does not include a projection of wholesale electricity prices that correspond to the energy cost savings estimate of $780 million to $1.2 billion. As a result, Staff is unable to provide the Commission with a complete assessment of Access Northeast's ability to mitigate future winter electricity prices. We consider this to be a major weakness of the ICF analysis. Further, because ICF used the same methodology to develop the cost savings estimates in its report on the NED project, this criticism applies to that report also.

[37] Given the weather conditions in 2013/14 were abnormal, the $1.2 billion energy cost savings estimate can reasonably be interpreted as being consistent with some hybrid of normal and abnormal weather conditions.

(ii) Abnormal Weather Analysis

ICF estimates that had the Access Northeast project been in operation during the abnormally cold winter of 2013/14, it could have eliminated gas price spikes on 49 days resulting in wholesale energy cost savings totaling about $2.5 billion. ICF attributes this cost saving to 0.5 Bcf/day of incremental pipeline capacity plus daily withdrawals of LNG that vary depending on the actual load factor on New England's pipeline system. On days when the actual load factor was at or above 95%, higher LNG withdrawals were assumed to bring the load factor below 75%. When load factors on New England pipelines are at or below 75%, natural gas price spikes and associated electric price spikes are much less likely to occur, according to ICF.

Benefit-Cost Analysis

Whether during normal or abnormal weather conditions, ICF asserts that the potential annual energy cost savings from adding new gas infrastructure to the region will exceed by a large margin the levelized annual cost of constructing that infrastructure, which it estimated at approximately $400 million.[38] To be conservative, we use a levelized annual cost of $480 million. Based on this cost estimate and the wholesale energy cost savings as described above, the Access Northeast project would produce benefit to cost ratios of 1.63 and 2.5 not including the value of enhanced electric grid reliability associated with providing secure winter fuel supplies to 5,000 MW of gas generation capacity. The total cost to consumers of the project under our annual cost estimate would be $9.6 billion.[39]

However, ICF's estimate of the levelized annual cost of the project was prepared at a time when the sponsors were considering providing the proposed LNG storage service out of upgraded LNG storage facilities owned and operated by affiliated LDCs. Since that time, Eversource has decided not to upgrade those facilities and instead is proposing to construct two new LNG storage tanks and associated liquefaction and vaporization facilities at an existing site in Acushnet, Massachusetts. The cost of this project is reported to be $600 million which may include the cost of a new, three-mile pipeline from the Acushnet facility to an interconnection with Algonquin, raising the total investment cost for the Access Northeast project to about $3 billion.[40] Although Eversource has declined to provide an updated estimate of the levelized annual cost of the project, Staff estimates the new cost could be about $600 million based on the same 20% carrying charge rate. A levelized annual cost of $600 million would lower the benefit to cost ratios to 1.3 and 2.0.

Cost to Electric Consumers

Based on a $600 million levelized annual cost for the project and assuming only Eversource and National Grid EDCs choosing to enter contracts with project sponsors, New Hampshire's Eversource affiliate Public Service Company of New Hampshire (PSNH) would be allocated 9% of the total capacity of the project at an annual cost of $54 million.[41] If this cost is recovered from all PSNH customers via a per kWh distribution surcharge, we estimate the surcharge would be about $0.0068 per kWh or 6.8 mills per kWh. To put this surcharge in context, this is 106% higher than New Hampshire System Benefit Charge

[38] This annual cost is based on a total investment cost for the project of $2.4 billion and a 16.667% carrying charge rate. To be conservative when calculating the benefit to cost ratio for the project, we adopted the 20% carrying charge rate recommended by Black & Veatch for interstate natural gas pipelines employing 20-year firm transportation contracts. This produces an annual cost of $480 million.
[39] $9.6 billion is the product of a $480 million levelized annual cost and a 20-year contract term.
[40] The two new tanks would have a combined useable storage capacity of 6.0 Bcf.
[41] See Eversource's August 20, 2015 response to Staff Follow-Up Question.

(SBC). However, we consider 6.8 mills per kWh to be a worst case outcome assuming of course the $600 million annual cost estimate is reasonable. If all other EDCs in the region (including the region's consumer-owned municipal and cooperative utilities) agreed to shoulder their load ratio shares of project costs, then the size of the surcharge could be reduced. However, because the Eversource and National Grid affiliated EDCs account for approximately 71% of all retail sales by EDCs in New England, the surcharge would not fall below 4.8 mills per kWh.

The discussion thus far has assumed that retail electricity consumers incur the full cost of the project and gas generators, the ultimate users of the purchased capacity, none. However, under the NESCOE model adopted by Eversource in its comments, capacity contracted by EDCs would be released to gas generators through an auction administered by a capacity manager. Revenues received by the capacity manager from winning bidders would be returned to the EDCs as an offset to the cost of the project as would any revenues received from capacity sales in the secondary market if generators choose not to purchase all of the capacity in the auction. Clearly, the higher the price paid by generators (or by end users in the secondary market) for released capacity, the greater the offset to project costs and the lower the distribution surcharge.

In this regard, it is worth considering the comments of CLEC on the potential for gas generators to benefit from purchasing the rights to firm transportation capacity. CLEC estimates that as long as the incremental pipeline capacity of the NED project does not exceed 1 Bcf/day, the throughput from this new capacity will be less than the combined electric and non-electric market demand for natural gas in New England on most days of the year and certainly on winter days. This means that the remaining gas demand must be met by existing and other new pipelines at prices based in large part on the price of gas at higher cost receipt points. And it will be the prices at these higher cost receipt points that will set the clearing prices in the New England natural gas market. Moreover, CLEC believes that if a generator shipping gas on NED is able to secure gas delivered to its facility at a lower price than other generators shipping gas on other pipelines, then the bid price of the higher gas cost generator will set the LMP of electricity, and the difference between the LMP and the bid of the lower gas cost generator will be retained by that generator as a form of energy-market rent. Staff believes this energy-market rent could function as an incentive to gas generators to not only bid for EDC capacity but to bid prices higher than otherwise, potentially producing a larger offset to project costs and a reduced distribution surcharge.

NORTHEAST ENERGY DIRECT

Project Overview

Tennessee Gas Pipeline Company (TGP), a Kinder Morgan subsidiary, currently plays a significant role in transporting gas to generators that supply the ISO-NE electric grid. While TGP is directly connected to only 27% of total installed gas capacity, or about 4,900 MW, ICF estimates that during 2012-14 TGP was responsible for supplying gas to over 9,000 MW of generation capacity or about 50% of total gas capacity.[42] TGP was able to achieve this level of coverage by delivering gas on behalf of customers directly connected to Algonquin via the Mahwah, New Jersey and Mendon, Massachusetts interconnections. Upon completion of the Northeast Energy Direct (NED) project, those specific pipeline

[42] New England Energy Market Outlook – Demand for Natural Gas Capacity and Impact of the Northeast Energy Direct Project, ICF International, 2015, Page 10.

interconnections will be maintained and, importantly, TGP will have the ability to deliver additional volumes to Portland Natural Gas Transmission Service (PNGTS), Maritimes and Northeast (Maritimes), Iroquois Gas Transmission (Iroquois) and Algonquin.[43] Therefore, as a result of the NED project, TGP will have the ability to physically deliver into every pipeline system serving New England as well as to incrementally serve markets along its own pipeline system. In addition, the NED project will play a critical role in serving future new generation expected to be located in proximity to the Central Massachusetts Hub (Mass Hub) area.[44]

The NED project comprises two separate segments or paths: the Supply Path and the Market Path. The Supply Path will supply up to 1.2 Bcf/day of Marcellus Shale gas from one or more receipt points on TGP's 300 Line[45] in Northeast Pennsylvania and extend to Wright, New York where it will interconnect with TGP's existing 200 Line, the proposed Constitution pipeline,[46] and the Iroquois pipeline. Figure 4 shows the existing TGP pipeline system and the proposed route for the NED project.

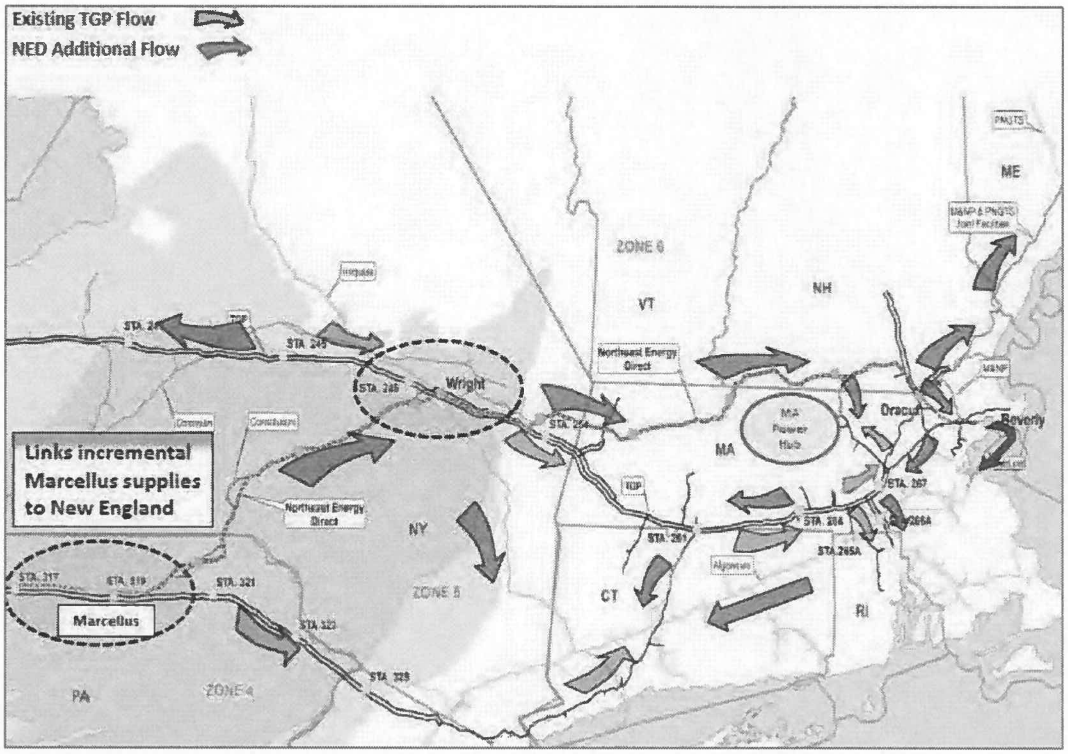

Figure 4: Tennessee Gas Pipeline Company's Northeast Energy Direct Project

The Market Path will be able to deliver up to 1.3 Bcf/day of incremental gas supplies from its receipt point at Wright, New York to interconnections near Dracut, Massachusetts with PNGTS, Maritimes, and TGP's 200 Line. Although the NED project is technically classified as a greenfield project, TGP asserts

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[43] TGP states that existing gas generators currently served by Algonquin and Maritimes will be free to contract for firm transportation services on the Market Path.

[44] TGP contends that ISO-NE has identified the Mass Hub as an area on the electric grid with few constraints and therefore ideal for adding new gas generation to replace retiring old and inefficient non-gas generation.

[45] See NED's Open Season for PowerServe, September 8, 2015.

[46] The Constitution pipeline has already received the necessary FERC certification to deliver gas to Wright, New York.

that 91% of the Market Path route will be co-located along existing electric utility rights of way or adjacent to the existing 200 Line. TGP initiated the FERC pre-filing process in September 2014 and expects to begin construction on the Market Path in January 2017 and be fully operational by November 2018.[47]

Because the primary delivery point for the Market Path will be located at the eastern end of the New England pipeline system, the NED project will be capable of flowing gas from an easterly direction into the TGP's existing 200 Line and the Algonquin pipeline[48] via the Joint Facilities and the Hubline. The NED project will also allow generators directly connected to the Algonquin pipeline to receive incremental gas supplies via TGP's interconnection with Algonquin at Mendon, Massachusetts provided such generators enter into firm transportation contracts with TGP and Algonquin.

As noted, the NED project is designed to interconnect near Dracut, Massachusetts with TGP's 200 Line and the Maritimes and PNGTS pipelines. The interconnection with TGP's 200 Line will enable natural gas supplies to flow south from Dracut to LDCs and gas generators directly connected to TGP's existing system in Massachusetts, Connecticut, and Rhode Island. The interconnection with the Maritimes and PNGTS pipelines through the Joint Facilities, together with the anticipated reversal of gas flow along those facilities from south to north, will enable the NED project to access more New England customers in New Hampshire, Maine and in the Atlantic Canada region.

Currently, TGP has secured long-term commitments from nine New England LDCs for approximately 0.55 Bcf/day of the NED Market Path capacity, leaving approximately 0.75 Bcf/d of incremental capacity available to EDCs for release to gas generators, enough to supply between 3,900 MW and 4,500 MW of generation depending on the heat rates of such generators.[49] TGP has announced that it will meet its LDC commitments by constructing a 30-inch pipeline and sufficient compression to meet those firm commitments.[50] Subject to additional long-term commitments with New England EDCs, TGP will increase the capacity of the Market Path up to 1.3 Bcf/day by adding incremental compression.[51]

Receipt Points

While the rates for firm transportation service largely determine a project's cost, the point of receipt of natural gas plays an important though not conclusive role in determining project benefits. This is because the price of natural gas often varies depending on where each project interconnects to the rest of the natural gas pipeline network. As noted, the primary receipt point for the NED project is Wright, New York, though EDCs and LDCs may elect to receive some or all of their gas supplies upstream of that point within the Marcellus Shale production area if they expect the price of natural gas at Wright to materially exceed the price in the production area plus the cost of firm transportation on the Supply Path for a significant portion of the contract term.

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[47] See TGP response to Staff Initial Question 14.

[48] Spectra asserts that NED deliveries to the Algonquin pipeline from the east are limited by constraints on the Hubline.

[49] See TGP response to Question 11 in Second Set of Staff Questions.

[50] TGP states that it has also executed binding precedent agreements for firm transportation service on the NED Supply Path and is in the final stages of negotiations with other LDCs, gas producers and other market participants. See NED Open Season for PowerServe Firm Service, September 8, 2015.

[51] See July 16, 2015 press release from Kinder Morgan announcing its decision to proceed with the Market Path segment of the NED project.

According to TGP, the option to purchase gas in the Marcellus Shale production area provides EDCs and LDCs direct access to abundant supplies of low-cost natural gas from more than twenty different producers at an incremental cost equal to the firm transportation rate on the Supply Path. Moreover, TGP contends this is a significant advantage over other proposed pipeline projects including Access Northeast that only offer access to natural gas at downstream interconnects supplied by only a few producers. In support, TGP points to a study prepared on its behalf by Competitive Energy Services (CES) that compared natural gas prices at points that could be accessed by various New England pipeline expansion projects. That study found that the price of gas at Wright, New York could be purchased at a price equal to the price of gas in the Marcellus Shale production area plus transportation on the Supply Path whereas the price of gas at the Mahwah and Ramapo receipt points on Access Northeast would be substantially higher equivalent to TETCO M3 pricing.

Spectra argues that the analysis performed by CES is fundamentally flawed. In summary, Spectra asserts CES reached its conclusion by focusing on only two factors: (1) the current depressed price of natural price in the Marcellus Shale production area and (2) a transportation charge for a project that has no announced commitments. Additionally, Spectra claims that CES neglected to factor in real influences on the future price of gas at Wright such as the current and future demand on Iroquois, the current premium pricing for Iroquois supplies that primarily originate from Canada, and the likelihood that those premium Canadian supplies and markets through reverse flow on Iroquois could result in a price at Wright that may trade at a significant premium to TETCO M3. Finally, Spectra contends that CES ignored what it believes could be a significant flattening of TETCO M3 prices relative to Marcellus production area prices through the construction of substantial pipeline expansion projects, into, within and around TETCO M3.

Firm Transportation Services

Firm transportation rates on the Market Path will vary depending on the delivery point. For example, generators that select Dracut, Massachusetts as the primary delivery point will pay the "Wright to Dracut" rate whereas generators that select delivery points on the 200 Line in Massachusetts will pay a "Wright to downstream of Dracut" rate. The "Wright to Dracut" rate will be set at a discount to the "Wright to downstream of Dracut" rate to reflect the fact that generators directly connected to the Market Path will not incur the cost of transportation on TGP's existing 200 Line including the costs of any new investments on that line to reach generators. The "Wright to downstream of Dracut" rate will also apply to generators directly connected to TGP's 300 Line in Connecticut or the Rhode Island lateral off of the 200 Line. Finally, generators located in the Mass Hub area will pay either the "Wright to Dracut" rate if they are directly connected to the Market Path pipeline or the higher "Wright to Downstream of Dracut" rate if they are connected to the 200 Line.

Enhanced Transportation Service

The rate for firm transportation service will also vary depending on whether the customer is an LDC or an EDC releasing capacity to gas generators. Gas generators may require enhanced transportation services to accommodate large load swings as they respond to rapid changes in power system demand or system contingencies, often with little no time to notify pipelines of their transportation needs. In order to ensure gas generators have access to natural gas transportation services when needed, TGP intends to offer an optional no-notice transportation service[52] that utilizes the NED facilities, reserved

[52] LDCs generally receive gas on a uniform basis throughout the gas day.

capacity on TGP's existing system and regional storage and/or line pack. Generators may select from the following no-notice service options: (a) a supply service option supported by regional storage or (b) an auto park and loan service supported by regional storage and/or line pack. TGP will reserve capacity on the pipeline to provide the no-notice service. Importantly, as currently envisaged by TGP, gas generators will be responsible for maintaining sufficient quantities of gas in storage to satisfy their no-notice service requirements. Staff interprets this language to mean that the commodity cost of gas withdrawn from storage will equal the weighted average cost of gas in inventory. Naturally, the rates charged to generators for these no-notice services are expected to be higher than the rate charged to LDCs. The higher rate for EDCs will recoup the incremental capital costs TGP incurs to provide a higher quality service that enhances electric reliability.

Reliability and Energy Cost Savings Benefit

A. Reliability Benefits

The New England region as a whole stands to benefit from the NED project in two significant ways: by improving electric grid reliability and lowering gas and electricity prices to consumers. As regards the first benefit, the problem of non-firm gas supplies to gas generators has been particularly acute in New England in recent years, resulting in impaired electric grid reliability on the coldest winter days when gas is scarce and service interruptions become more common. According to TGP, the NED project will provide enhanced delivery of firm gas supplies to between 3,900 MW to 4,500 MW of existing generation on the coldest winter days and potentially large quantities of future gas generation in and around the Mass Hub area where new generation would most conveniently be located to ensure reliability in the regional power market.[53] This future gas generation would replace some of the 8,300 MW of existing nuclear, oil and coal generation expected to retire by 2020. In addition, by providing deliveries to Dracut, Massachusetts, NED could enhance reliability for generators on the Algonquin, PNGTS and Maritimes pipelines assuming appropriate modifications to those pipelines and available transportation capacity on NED.

B. Energy Benefits

Regarding energy benefits, TGP engaged ICF to analyze the potential energy cost savings that might arise from the construction of the NED project. The principal objectives of ICF's analysis were to quantify future differences between the region's demand for natural gas and existing gas supply sources and the financial benefits for consumers if new pipeline capacity is added to narrow those differences.

Even though TGP serves a smaller proportion of the region's existing gas generation market than Algonquin and Maritimes pipelines combined, ICF estimated that on average New England's wholesale energy costs could be reduced by $2.1 billion to $2.8 billion a year for the ten-year period after NED is placed in service: substantially higher than the $780 million to $1.2 billion per year cost savings estimated for the Access Northeast project, which we discussed in detail above.[54] The difference is explained by the much larger NED project, which adds 1.3 Bcf/day of incremental pipeline capacity to

[53] If the proposed 0.75 Bcf/day of incremental capacity on NED is accounted for by existing generators directly or indirectly connected to TGP or other New England pipelines, additional supplies to future gas generation in the Hub area would require an expansion of NED above the currently proposed 1.3 Bcf/day level.

[54] Both estimates were prepared by ICF using the same methodology but under separate engagements.

the New England pipeline system whereas Access Northeast adds the equivalent of 0.6 Bcf/day of incremental pipeline capacity.[55]

Normal Weather Analysis

As with the analysis conducted for the Access Northeast project, ICF conducted a normal weather analysis with and without NED and without consideration of volatility effects. The results of that analysis are presented in Figure 5 below, which shows considerably larger reductions in average peak winter month natural prices due to NED compared to Access Northeast. Without NED, average January gas prices steadily increase over time from about $15/MMBtu in 2019 and $30/MMBtu in 2028.[56] To put these prices in context, the average Algonquin citygate price for January 2014, an extremely cold month, was about $23/MMBtu and for February 2015, the coldest month on record according to ISO-NE, about $17/MMBtu.

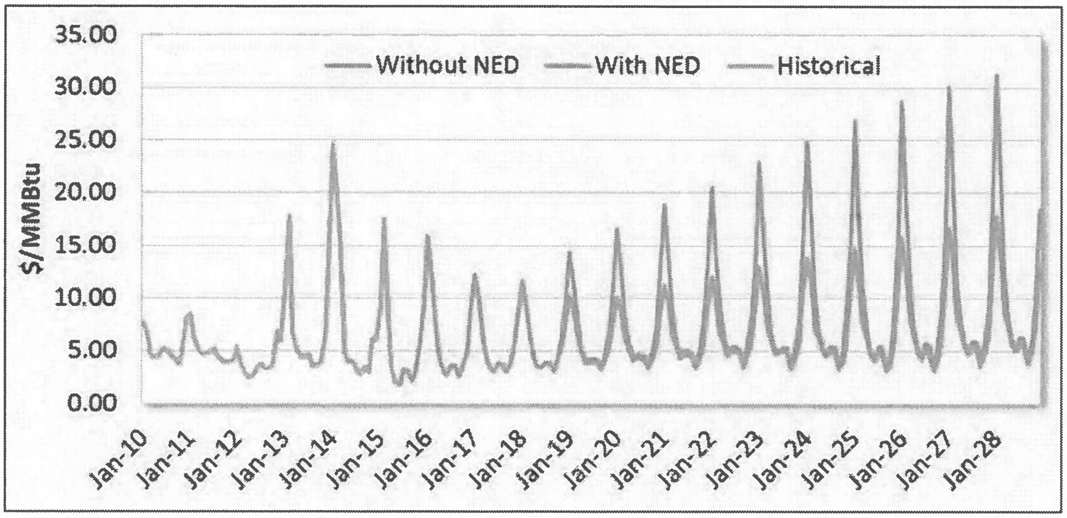

Figure 5: ICF's natural gas price forecast for New England (excluding volatility reduction benefits)

With NED, average January gas prices are projected to range from about $10/MMBtu to about $17/MMBtu over the same time period.

(ii) Abnormal Weather Analysis

In order to estimate the impact of the NED project under abnormal weather conditions, ICF analyzed New England's natural gas and electric markets during the "polar vortex" winter of 2013/14. It found that NED could have eliminated gas price spikes on 86 days during the 2013/14 winter resulting in wholesale energy cost savings totaling about $3.7 billion. ICF attributes this cost saving to the 1.3 Bcf/day of incremental pipeline capacity reducing the load factor on New England pipelines to levels equal to or below 75%. When load factors are at or below 75%, ICF asserts that natural gas price spikes and associated electricity price spikes are much less likely to occur.

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[55] The fact that 0.55 Bcf/day of the NED capacity will be contracted to LDCs rather than gas generators does not diminish the potential for that portion of the project to reduce natural gas prices for the benefit of regional electricity consumers.

[56] The projection of natural gas prices absent incremental capacity has increased relative to the projection in ICF's Access Northeast report. ICF attributes this to the use of an updated gas demand forecast that reflects increased growth in the demand for gas in the power sector and higher than previously expected demand for gas in Atlantic Canada.

Benefit-Cost Analysis

According to ICF, the investment cost for the electric portion of the NED project is $2.0 billion,[57] equivalent to a levelized annual cost of $400 million over a 20-year contract term.[58] At $400 million per year, electric customers would pay $8 billion over the contract term. Based on the above benefits and costs, we estimate the NED project would produce a benefit to cost ratio in the range 5.25 to 7.0 not including the value of enhanced electric grid reliability or the annual costs of providing enhanced transportation services.

Cost to Electric Consumers

Based on a $400 million levelized annual cost for the electric portion of the NED project and the assumption that only Eversource and National Grid EDCs choose to enter contracts with TGP, New Hampshire's Eversource affiliate PSNH would be allocated 9% of the total capacity of the project at an annual cost of $36.0 million.[59] If this cost is recovered from all PSNH customers via a per kWh distribution surcharge, we estimate the surcharge would be about $0.0046 per kWh or 4.6 mills per kWh. For context, this is about 40% higher than the New Hampshire System Benefit Charge (SBC). If all other EDCs in the region (including the region's consumer-owned municipal and cooperative utilities) agreed to shoulder their load ratio shares of project costs, we calculate the size of the distribution surcharge could be reduced to about 3.3 mills per kWh.

However, as noted above in the section addressing the cost to consumers of the Access Northeast project, the surcharge can be reduced further by offsetting the electric portion of the project cost with revenues received from releasing capacity contracted by EDCs to gas generators through an auction process. As explained, the higher the price paid by generators for released capacity the greater will be the offset to protect costs and the lower will be the distribution surcharge.

PORTLAND NATURAL GAS TRANSMISSION SYSTEM NEW EXPANSION

Project Overview

Portland Natural Gas Transmission System (PNGTS), a subsidiary of TransCanada and Gaz Metro, is a high pressure interstate natural gas pipeline providing transportation services to LDCs, paper mills, and electric generation plants throughout New England. PNGTS' pipeline extends in a southeasterly direction from a point on the border between the United States and Canada near Pittsburg, New Hampshire, where it interconnects with the TransCanada Pipeline. The PNGTS pipeline passes through New Hampshire, Vermont, and Maine to interconnections with Maritimes at Westbrook, Maine and TGP near Dracut and Haverill, Massachusetts. Figure 6 is a map of the existing PNGTS pipeline. The pipeline between Westbrook, Maine and Dracut, Massachusetts is known as the Joint Facilities because they are jointly owned by PNGTS and Maritimes.

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[57] Staff believes this estimate excludes investments to provide firm transportation customers with enhanced or no-notice transportation services.
[58] $400 million is equivalent to a carrying charge rate of 20% for pipelines 20-year firm transportation contracts. This is the same carrying charge rate used to calculate the levelized annual cost for the Access Northeast project.
[59] See Eversource's August 20, 2015 response to Staff's Follow-Up Question.

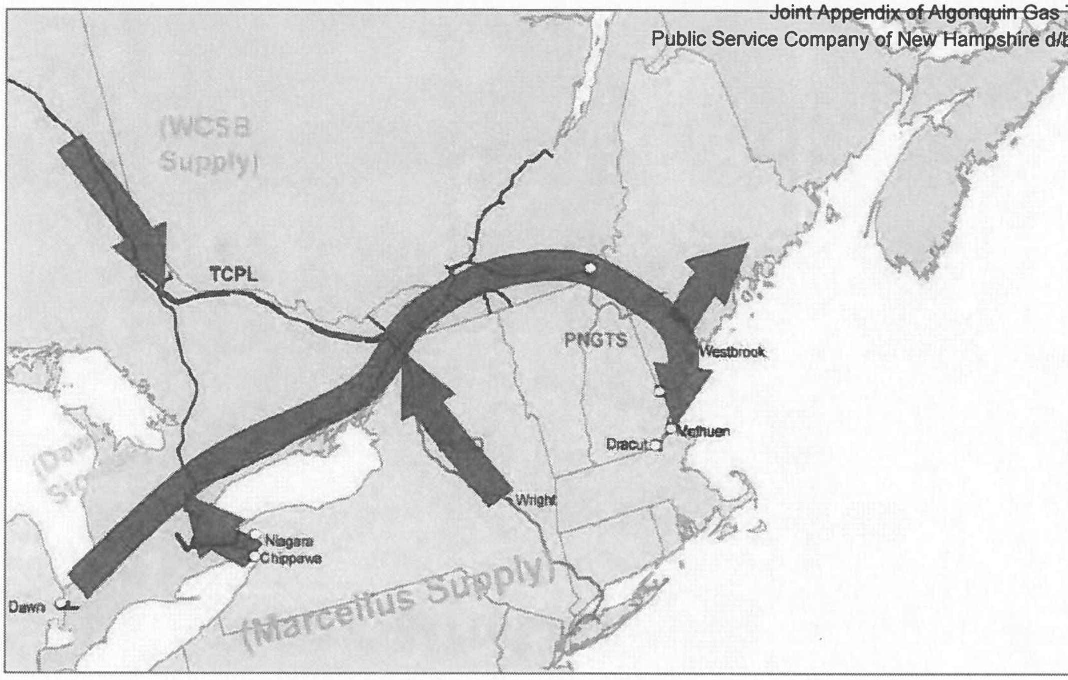

Figure 6: PNGTS Supply. Storage Access Options

PNGTS is in the early stages of developing a new expansion of its system that would be in addition to the capacity added as a result of its recent Continent-to-Coast (C2C) expansion project. By efficiently expanding its existing pipeline system, PNGTS believes it can offer EDCs a competitive alternative to the Access Northeast and NED projects. PNGTS is presently considering two scenarios. The first scenario is a scalable medium-sized project with incremental firm capacity up to 0.6 Bcf/day over a level that includes the C2C project. The new expansion would run from Pittsburg, New Hampshire to either Westbrook, Maine or Dracut, Massachusetts depending on the delivering points selected by expansion customers and provide firm transportation service to EDCs, LDCs and other markets in New England through the addition of three new compressor stations. The second scenario is a large expansion project up to 0.9 Bcf/day of incremental firm capacity over a level that includes the C2C project. This project would serve the same markets as the smaller project and would be based on the addition of two new compressor stations and 130 miles of looping of the existing 24" line. PNGTS states that any expansion of the Joint Facilities would depend on an analysis of existing facilities performed in conjunction with other changes proposed by co-owner Maritimes.

In addition to the above mentioned improvements on the PNGTS pipeline, incremental capacity would be required upstream on the TransCanada and Iroquois pipelines. TransCanada will add compressor and pipeline facilities from its interconnection with Iroquois at Waddington, New York to Pittsburgh, New Hampshire. Under the 0.6 Bcf/day scenario, TransCanada will add new compressors at 5 locations but looping would not be necessary. Under the 0.9 Bcf/day scenario, TransCanada will add new compressors at 5 locations and 143 miles of 30 inch looping.

In contrast, Iroquois appears to have firm capacity available that PNGTS could utilize to reverse flow and access Marcellus gas at the Wright, NY trading point. PNGTS could also access Mid-Continent and Marcellus gas at Dawn, Niagara and Chippawa receipt points off of TransCanada. According to PNGTS, the gas supply diversity these receipt points offer will provide substantial benefits to shippers. For example, if the price of gas at Wright were to change over time, access to supplies from Dawn and Alberta could prove valuable to shippers.

That said, PNGTS expects Wright to be a liquid and reliable source of Marcellus Shale supply following the completion of the Constitution pipeline and TGP's proposed "Supply Path", which initially will deliver 0.65 Bcf/day and 1.2 Bcf/day respectively into the Iroquois pipeline. In addition, there is potential for expansion of both the Constitution and Supply Paths.

Enhanced Transportation Service

PNGTS does not currently offer generators on its system a no-notice service nor has it committed to do so in the future. The most it would say is that it is currently evaluating with counterparties the possibility of offering generators a no-notice service based on peaking facilities. That said, PNGTS currently has a firm transportation Hourly Reserve Service (HRS) rate schedule that would be available to any future expansion customers. According to PNGTS, HRS was specifically designed to help electric generation customers manage variations in hourly load needs. It does so by providing a generator the flexibility to contract for firm transportation service up to a specified Maximum Hourly Quantity (MHQ), as well as a specified Maximum Daily Quantity (MDQ). The MHQ allows the generator to receive delivery of its MDQ at an accelerated rate over a specified number of hours during the gas day, which is likely to be particularly useful to electric generators with loads that vary significantly during the gas day. PNGTS uses line pack as the basis of its HRS.

PNGTS states that a generator may contract for one of five different firm hourly flow options, ranging from 4.16% of its MDQ (which translates into uniform deliveries over a 24-hour gas day) up to 8.33% of the generators MDQ, which translates into full daily deliveries over 12 hours. By electing to receive firm higher hourly deliveries during a gas day, the generator will pay a higher reservation rate for the additional firm capacity required to provide the higher hourly deliverability. Also, the reservation rate will vary based on the firm hourly flow rate elected by the generator. The higher the firm hourly flow rate, the higher the reservation charge.

PNGTS also has a Park and Loan (PAL) service which generators can use to balance on a daily basis gas supplies and loads. PAL customers can request available capacity to "park" gas they have already scheduled and will not use, or receive a "loan" of gas from PNGTS to supplement their requirements. hourly or NAESB cycle basis.

Reliability Benefits and Energy Cost Savings

Unlike the Access Northeast and NED projects, PNGTS presented no studies of the potential energy cost savings associated with its proposed new expansion project. Nor was PNGTS willing to share with Staff its estimate of the total investment cost of the project, the associated annual cost, or details of the firm transportation rates that potential generators might pay to transport gas from receipt point to delivery point, citing the early stage of its project development cycle. For these reasons, Staff is unable to provide the Commission with any of the most basic information associated with this or any expansion project including its total investment cost, the associated annual cost, the required distribution surcharge, the estimated benefit to cost ratio, the potential reduction in wholesale electricity prices, or even the amount of new firm capacity that would be available to generators. Without such information, Staff can offer no quantitative assessment of the project's ability to mitigate wholesale electricity prices.

COALITION TO LOWER ENERGY COSTS

Introduction and Cost Savings Analysis

The Coalition to Lower Energy Costs (CLEC) is a non-profit association of individual consumers, large energy consumers, labor unions and institutions seeking to eliminate the threat to New England's families and economy from skyrocketing natural gas and electric prices. CLEC advocates for increased renewable energy, energy efficiency, demand response and new energy infrastructure to give natural gas and electricity consumers access to an adequate gas supply, a cleaner energy portfolio and lower energy costs.

CLEC contends that the best available information shows that the region will require large amounts of additional pipeline capacity from two major new or substantially new pipelines to fully solve the high electricity price problem. This pipeline capacity cannot, according to CLEC, be provided by the region's electricity market, which is designed on principles of theoretical short term "efficiency" that ISO-NE itself acknowledges cannot support the investment needed to remedy the problem. In this investigation, CLEC advocates for the creation of mechanisms to require each EDC in New England to contract to purchase capacity from interstate natural gas pipelines in an amount equal to the EDC's pro rata share of New England electricity consumption.

According to CLEC, the NED and Access Northeast projects benefit New England separately and then synergistically, providing 2.2 Bcf/d in additional capacity. Access Northeast serves southern New England directly whereas NED delivers low cost gas to the Dracut trading point where it can be delivered to generators directly connected to TGP's existing system and other pipelines.

CLEC's claim that the region will need the capacity from two major new pipelines to fully solve the high electricity price problem, it submitted a February 2014 study prepared by Competitive Energy Services (CES).[60] That study was updated by CES in a December 5, 2014 report titled Report to Tennessee Gas Pipeline Company L.L.C. and included in this investigation as part of a TGP discovery response. In that updated study, CES estimated the economic value (i.e., wholesale energy cost savings) of hypothetical 0.2 Bcf/day increments of pipeline capacity and found that between 2.0 to 2.4 Bcf/day of pipeline capacity was needed to completely eliminate the constraints on regional pipelines. Absent such capacity additions, CES estimates that regional electricity consumers would pay approximately $3.0 billion annually in additional wholesale energy costs; costs that will place the region at a severe economic disadvantage relative to neighboring regions of the country. As can be seen in Appendix 1, Page 1 below, with each 0.2 Bcf/day increment of capacity the cumulative power cost savings increase but at a diminishing rate suggesting that as the additional capacity approaches 2.4 Bcf/day the pipeline constraints become insignificant and the cumulative annual savings level off at about $3 billion.

Applying the results of CES' work to NED, which as noted is a 1.3 Bcf/day project, produces cumulative annual wholesale energy cost savings of about $2.5 million,[61] well within the range of cost savings projected by ICF for the NED project.

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[60] "Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices" February 17, 2014.
[61] This estimate assumes NED is the first project built.

Assessment of CES's Energy Cost Savings Analysis

Staff has reviewed CES' description of its dispatch model and concluded that some of the simplifying assumptions understate the estimated energy cost savings while others overstate the savings. For example, CES assumed that the spot price for natural gas in New England would be \$5/MMBtu during any hour when the combined demand for natural gas from LDCs and gas generators was less than the combined capacities of the region's pipelines. Other consulting firms such as ICF and Black & Veatch assert there is strong empirical evidence for natural gas prices to spike whenever pipeline utilization rates exceed 75%. This suggests that CES' \$5/MMBtu gas price assumption understates gas prices and hence energy costs under the base case scenario and as result understates the potential cost savings associated with incremental pipeline capacity.

The updated dispatch model used by CES to estimate cost savings reflects changes in several important variables including an expected decline in north-to south gas flow on Maritimes out of Canada; increased pipeline capacity into New England to reflect the likelihood that the AIM and TGP Connecticut Expansion project will get built; increased peak day LDC gas demands; and reduced oil and LNG prices to reflect changes in energy markets. Despite these changes, it is important to note that the modeling results depend in large part on two critical variables: the number of hours LNG-fueled generation is estimated to be on the margin prior to the addition of incremental capacity; and the assumed price of LNG. Changes in these variables can significantly impact the modeling results.

Because energy cost savings are directly proportional to the difference between the price of LNG and the price of natural gas assumed in the dispatch model, the expected future price of LNG is critically important to the modeling exercise. For example, had CES assumed that the price of LNG going forward was \$10/MMBtu instead of \$14/MMBtu, the cumulative annual cost savings at the 1.3 Bcf/day and 2.4 Bcf/day capacity levels are reduced to about \$1.4 billion and \$1.7 billion respectively. These results are shown in Appendix 1, Page 2. Because world LNG prices have fallen since CES completed its update, we believe the reduced cost savings may be more indicative of future benefits, all other things being equal.

However, all other things are rarely equal. If the addition of new pipeline capacity significantly reduces the demand for LNG during winter months it may be difficult for the region to maintain multiple LNG regasification facilities. In the event one of the two major LNG facilities closes, LNG prices may increase as the sole supplier seeks to recover its fixed costs over a smaller volume. Since this potential increase in LNG prices is not reflected in CES' estimate of energy costs under the incremental capacity scenarios, the cost savings estimates may be understated.

Finally, as noted, cost savings are driven in part by reductions in the number of hours LNG-fueled generation is on the margin. Data provided by CES shows that the modeled daily LNG requirements are higher than actual daily injections from Canaport in 2013, suggesting the cost savings are overstated. However, CES states that the model injections may be higher than Canaport deliveries during the winter months because it assumed that dual-fuel generators operate on LNG before they operate on oil when pipeline gas is un available, an assumption that may not hold under ISO-NE's Winter Reliability Program. That notwithstanding, CES states that since the delivered prices of oil and LNG are similar, the effect on energy cost savings should be small.

CONSERVATION LAW FOUNDATION

Initial Comments

Despite Staff's May 14 guidance letter encouraging stakeholders to submit non-pipeline as well as pipeline solutions to the high winter wholesale electricity price problem, the Conservation Law Foundation (CLF), a non-profit environmental advocacy organization, elected not to include in its submission a fully developed alternative to incremental pipeline capacity stating that the Commission appears to have already concluded that a pipeline solution is needed and that alternatives such as LNG natural gas are unreliable.

CLF believes that it is not necessary or wise for New Hampshire or the region to take actions that would promote construction of a new natural gas pipeline. CLF suggests that the volatility of the wholesale gas and electric markets argues against any intervention that requires funding by electricity consumers through significant subsidies. While Staff acknowledges there are risks to consumers of financing energy infrastructure projects through electric rates, we also recognize there are risks to consumers of continuing with the way things are now. For this reason, Staff disagrees with the contention that risk necessarily argues against market intervention. Clearly, state policy makers will have to weigh the potential benefits and costs of projects designed to reduce high winter electricity prices when deciding whether to have consumers fund those projects.

In support of its contention that the winter 2014/15 price reductions do not support state intervention in electricity markets, CLF notes that the futures markets for wholesale electricity are predicting another moderately priced winter. Specifically, it states that as of June 1, 2015 the CME Group's 5 MW day-ahead on-peak product for ISO-NE's internal hub for the six months December 2015 to May 2016 was trading at an average price of less than 8 ¢/kwh, significantly lower than the retail rates paid by some New Hampshire customers last winter. However, CLF was unable to provide any studies that show that wholesale electricity futures prices are a good predictor of future wholesale electricity prices. In fact, when asked to provide the corresponding CME Group futures market prices as of June 1, 2013 and June 1, 2014 in order to test their predictive ability, all CLF would say was that it does not have access to the requested information. The fact is that wholesale electricity prices are the result of many factors including weather conditions, the availability and price of LNG, fuel oil prices, and power plant outages, none of which can be predicted with great certainty. So, for CLF to suggest that prices for this coming winter could be far lower than last winter is completely contrary to what it says just two paragraphs later, which is that future wholesale prices are very uncertain.

CLF also contends that neither new pipeline capacity nor proximity to Marcellus Shale wellheads ensures protection from cold-weather price spikes. While it is true that the addition of incremental pipeline capacity in New England will have no effect on the constraints that drive price spikes on upstream pipelines such as those that deliver to the Texas Eastern M-3 trading point,[62] it is completely false to say that that incremental capacity will have no effect on prices at, say, Algonquin ciygates. The addition of incremental capacity to the regional pipeline system, whether through the expansion of existing pipelines or the construction of new pipelines, will reduce the constraints on Algonquin and TGP pipelines and lower gas and electricity market prices, particularly during the coldest winter days.

[62] The elimination of these price spikes will be resolved over time with investments in new upstream pipeline capacity expansion projects.

Furthermore, the extent of these price reductions depends on the amount of capacity added, as is so clearly demonstrated in the testimony of CES filed on behalf of CLEC, the report of ICF on behalf of Eversource and Spectra, and the report of ICF on behalf of TGP all of which are part of the record in this investigation. To be clear, Staff is not saying that the Access Northeast project or the NED project will eliminate the existing pipeline constraints. We are saying, however, that the benefits of each project will substantially exceed the project's implementation costs even ignoring the benefits of enhanced electric grid reliability.

On the potential role of LNG in addressing winter peak prices, the Commission in its FERC Fuel Assurance filing acknowledged that the reduction in electricity prices in winter 2014/15 compared to winter 2013/14 can be attributed in large part to a surge in gas sendout from the region's LNG import terminals, including previously idled offshore terminals. That surge, however, was made possible by a reduction in world LNG prices that enabled terminal operators to successfully compete with fuel oil and high priced pipeline natural gas to supply gas generators. Unfortunately, as ISO-NE has so clearly stated, there is no guarantee that the market conditions that enticed LNG tankers to New England in winter 2014/15 will recur in future winters. This means the very high prices of 2013/14 could reappear just as quickly as they disappeared in 2014/15 assuming of course similar extreme weather conditions. Finally, it is important to note that the increased availability of LNG in winter 2014/15 did not eliminate price spikes or energy cost premiums as CLF seems to imply. As can be seen in Figure 7 below, which is copied from Attachment 2 to Eversource's filing in this investigation, wholesale electricity prices continued to exhibit substantial volatility though not as high as in winter 2013/14. This volatility resulted in wholesale electricity costs in winter 2014/15 about $2 billion higher than winter 2011/12.

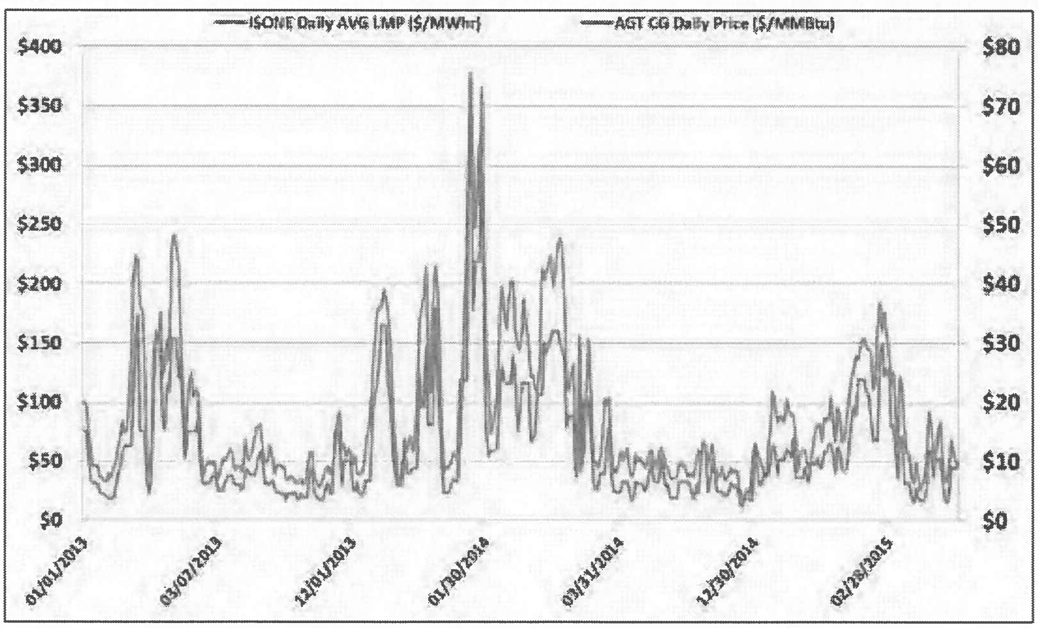

Figure 7: ISO-NE Winter Energy Market Prices (2013-2015)

Staff now turns to CLF's claim that the over 400,000 Dth/day of new LDC capacity associated with the Spectra AIM and TGP Connecticut Expansion projects, expected to be in service by November 2016, could achieve all or most of the objectives that special Commission action may target. If by this statement CLF is suggesting that the above referenced projects will alone result in a long-term reduction in winter period wholesale gas and electricity prices, Staff would dispute that claim. As Figure 3 in this report shows, and as we explain below in our response to similar comments by Unitil, under normal weather conditions and without the Access Northeast project peak winter gas prices are projected by ICF to fall during the 2016 through 2019 period as a direct result of the capacity added by the AIM, Connecticut Expansion and Atlantic Bridge projects. However, from 2019 through 2028 peak winter gas prices are projected to increase significantly due to expected strong growth in the demand for gas for heating and electric generation and associated growing supply constraints. That is, while gas and electricity consumers will continue to benefit from the new capacity throughout the term of the contracts, the forecast growth in the demand for gas is projected to result in price increases over time rather than decreases. In short, the new LDC capacity will not produce the long-term reduction in gas and electricity prices that presumably would be the goal of any regional pipeline capacity initiative.

CLF notes that LDCs currently release surplus pipeline capacity on the secondary market, and use the resulting revenues to reduce gas rates to residential and business customers. However, state intervention in the gas market that results in the procurement by generators of incremental pipeline capacity and lower natural gas prices will reduce the revenues available from the release of capacity and in turn raise the rates paid by gas customers, according to CLF.

Staff has several concerns with this argument. The first is that CLF's inability to quantify the alleged negative rate impact makes it difficult to determine whether this is an issue worthy of consideration. The second and far more important concern is that CLF fails to take into account the positive impact on natural gas prices and hence rates resulting from adding incremental pipeline capacity to the regional pipeline system. That is, the reduction in natural gas prices associated with new pipeline capacity will benefit gas consumers as well as electricity consumers.

Finally, CLF contends that Commission action to add new pipeline capacity to the region "is emphatically not a positive step for achieving the needed reductions in carbon emissions from the electric sector to achieve New England and New Hampshire's climate goals." However, when questioned on this issue, CLF was less emphatic and appeared to agree that displacing an existing non-gas generator that has a high CO2 emissions rate with a new combined cycle gas generator that has a low CO2 emissions rate would lower the average system-wide emissions rate and in the process contribute to reductions in carbon emissions.

Winter Only LNG "Pipeline" Solution

A. Project Overview

On August 31, just two weeks before Staff's report to the Commission was due, CLF supplemented its comments in the investigation with a 46 page report prepared by the consulting firm Skipping Stone that proposes a solution to what it terms New England's natural gas deliverability problem.[63] Because the report was presented by CLF in this investigation, Staff naturally assumed that the proposed solution was submitted as an alternative to the procurement of incremental pipeline capacity to solve the gas and electricity prices spikes that have plagued New England over the past few winters. However, it quickly became apparent that the principal purpose of the proposed solution was not to offer an incremental LNG capacity solution but instead to modify the gas supply procurement practices of New England's LDCs in order to reduce the cost of meeting peak winter gas demands and only secondarily

[63] *Solving New England's Gas Deliverability Problem Using LNG Storage and Market Incentives, Skipping Stone (undated).*

solve the high winter period electricity price problem. While a case could possibly be made that such a proposal is consistent with the Commission's Order, or at least Staff's broad interpretation of that Order, it would appear that our investigation is missing some obvious parties of interest including but not limited to LDCs, LDC consumers and the Commission's gas division. Those concerns notwithstanding, we summarize in the following pages the proposal put forth by Skipping Stone and offer our initial observations. Clearly, a proposal of this magnitude and complexity requires far more time and consideration than we have been able to devote to it over the past two weeks.

According to Skipping Stone, the most cost-effective way to address the current shortage of pipeline capacity is not to construct new or expanded pipelines from the west but to increase the utilization of the region's existing LNG infrastructure, which it defines as the combination of LDC-owned satellite LNG storage and vaporization facilities and onshore and offshore LNG import facilities. Under this solution, the LNG import facilities are used in conjunction with expanded truck deliveries to refill the satellite LNG facilities to effectively base-load what Skipping Stone claims are currently underutilized LDC assets.[64] This different use of existing satellite LNG facilities would create, according to Skipping Stone, a winter-only LNG "pipeline" for LDCs to meet their gas demands on peak days while maintaining excess supply available for sale on the secondary market to gas generators and other spot market consumers.

Skipping Stone contends that this different use of the satellite LNG assets would require advance contracting of approximately eight cargoes or 24 Bcf of LNG delivered over a 90 day winter period to meet 2020 gas demands, during which time LNG would be vaporized 50 days each winter when the demand for natural gas is projected to exceed pipeline capacity from the west with the excess supply available for release to gas generators.[65] Fifteen cargoes or 45 Bcf of LNG would be needed to meet forecasted 2030 gas demands.

Skipping Stone asserts that its solution is not only technically feasible, but would save LDC consumers initially over $340 million a year and as much as $4.4 billion over twenty years, as compared to new pipeline capacity, while also providing peak winter deliverability that will lower wholesale electricity prices on a scale comparable to new pipeline capacity additions.

B. Economics of Winter-Only LNG "Pipeline" vs. New Pipeline

For the purposes of this comparison, Skipping Stone assumes an LDC is faced with the option of entering into a precedent agreement to purchase 160,000 Dth/day (i.e., 0.16 Bcf/day) of incremental pipeline capacity[66] at a rate of $1.5 Dth/day or alternatively contract for 160,000 Dth/day of LNG for just 50 days.[67] While the former would cost $87.6 million per year in fixed cost exclusive of commodity costs, the latter would cost $76.7 million inclusive of gas cost.[68] After adding commodity costs[69] to the pipeline

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[64] According to Skipping Stone, the increased utilization of the region's LNG facilities will free up existing pipeline capacity under contract to LDCs that can in turn be released to the secondary market for the use of gas generators.
[65] On a September 11 conference call with Staff, Skipping Stone attributed the 50 day capacity deficit projection to a 2014 report by ICF International. It also stated that the 50 day capacity deficit applies to the years 2020 and 2030.
[66] The new or expanded pipeline is assumed to have a total capacity of 0.8 Bcf/day.
[67] That is, 8 Bcf of LNG gas supplies.
[68] Assumes an average landed LNG cost of $9.59/Dth (inclusive of margin for terminal operator) over the first 5 years and 8 Bcf of gas supply.
[69] Calculated as the product of 3.2 million Dth and an average natural gas price of $3.60 per Dth. The 3.2 million Dth is Skipping Stones estimate of the amount of gas actually needed.

option, the LDC cost saving would be about $22.4 million per year. Scaling this annual savings up to the full capacity of the pipeline would produce an annual savings of about $112 million for New England LDCs or approximately $2.2 billion over the 20-year life of transportation capacity contracts under the pipeline option. Skipping Stone asserts that only 3 Bcf of the 8 Bcf is actually needed to meet LDC capacity deficits leaving 5 Bcf for generators. That is, when scaled up to the full capacity of the pipeline, 9 Bcf of LNG is used to meet the capacity deficits.

Importantly, Skipping Stone says that "in order to facilitate this solution" regulators should permit LDCs to treat the difference between the landed cost of LNG and the cost of pipeline gas[70] (i.e., in the hypothetical $9.59/Dth of LNG on average over the 5 year period versus an assumed $3.60 /Dth winter average pipeline gas price over the same period) the same way they treat pipeline capacity payments: that is, as a fixed cost for accounting purposes.[71] This accounting treatment would allow the price of the surplus LNG to be sold to generators a price at least equal to the cost of pipeline gas, a result that means electric market clearing prices would be the same as if the LDC had purchased incremental pipeline capacity and released the rights to that capacity to gas generators. That is, the proposed accounting treatment is fundamental to achieving the wholesale energy cost savings that accrue to electric consumers under the pipeline capacity option.

While Staff does not take a position on the proposal at this time, we have one major concern. Our concern relates to the claim that the demand for natural gas exceeds pipeline capacity on just 50 days during the winter. If the region is capacity deficit on more than 50 days each winter then clearly the unmet electric sector demand for gas would increase as would the cost of the Skipping Stone proposal. In other words, the cost savings relative to the pipeline option would shrink. In this regard, it is important to note that ICF projects that in winter 2020 daily gas demand will exceed supply capacity under normal weather conditions on 63 days.[72] By 2035, the projected duration of capacity deficits lengthens to an estimated 113 days. Further, under design weather conditions ICF projects the duration of capacity deficits to be even longer ranging from 78 days in 2020 to 122 days in 2035. Clearly, if ICF's projections of capacity deficits are accurate, the volume of LNG required to meet the unmet electric sector gas demands (under both normal and design weather conditions) will be far greater than Skipping Stone has estimated, thus significantly reducing the cost savings relative to the pipeline option and decreasing the surplus gas supplies available for resale to gas generators.

Finally, because LDCs use the satellite LNG facilities to maintain gas distribution system reliability and help meet firm customer demands on peak winter demand days, Staff believes they will be very reluctant to use the associated capacity to mitigate non-firm gas and electricity price spikes.

NEW ENGLAND POWER GENERATORS ASSOCIATION

The New England Power Generators Association (NEPGA) is the trade association representing competitive electric generating companies that own approximately 25,000 MW of capacity throughout New England including 2,700 MW in New Hampshire. Most of these electric generators are fired by gas

[70] The cost of pipeline gas is defined as the price of gas at Henry Hub.
[71] Equivalent to $18 million per year.
[72] New England Energy Market Outlook – Demand for Natural Gas Capacity and Impact of the Northeast Energy Direct Projects, ICF International, September 2015.

alone or by a combination of gas and oil. According to NEPGA, New Hampshire's member companies provide over $46 million annually in state and local taxes and jobs for nearly 800 skilled employees.

NEPGA urges the Commission not to intervene in the competitive energy marketplace in support of out-of-market energy infrastructure initiatives that seek to subsidize interstate natural gas pipeline expansion projects and large-scale hydroelectric and wind energy purchases via the construction of high voltage transmission lines. NEPGA's principal argument in support of its recommendation is that New England's electricity and fuel supply markets are performing efficiently as evidenced by the significant investments being made in new power plants, the development of new pipelines, and the implementation of new and creative concepts to increase energy supplies, all without consumers bearing the risks associated with those investments. Undercutting those efforts through subsidized out-of-market initiatives could have significant unintended consequences for the power system and electricity consumers, according to NEPGA.

In the electric sector, NEPGA contends that the markets are responding appropriately and aggressively to price signals by making necessary investments to support reliability and enhance competitive pricing while continuing to meet or exceed state and federal environmental mandates. NEPGA notes that over 1,700 MW of new power plants have been selected in recent Forward Capacity Market (FCM) auctions and a further 16,000 MW of new resources have provided expressions of interest for the next auction commencing in early 2016. Subsidized initiatives of the type described above could undermine those investments as well as investments in power plants already operating and providing services to consumers, says NEPGA.

NEPGA also contends that LNG can play an important role in meeting winter electricity demands and reducing natural gas prices, presumably as an alternative to out-of-market pipeline expansion initiatives, although this argument does not actually appear in its comments. Instead, NEPGA seems content to draw attention to the 31 Bcf of LNG injections during the December 2014 through February 2015 period, almost double the 16 Bcf of gas from LNG imports the previous winter.

In the natural gas sector, NEPGA states that several natural gas pipeline projects have recently been proposed in New England with the potential to bring up to 2.74 Bcf/day of new capacity into service between 2016 and 2018, of which over 0.8 Bcf/day has already been subscribed and potentially available to generators during the winter months.

Turning to NEPGA's claim that three pipeline projects totaling 2.74 Bcf/day of new capacity have been proposed with the potential to reduce winter constraints, it is important to note that the Northeast Energy Direct project has been reduced in size from 2.2 to 1.3 Bcf/day. More importantly, that scaled down project will not go forward without regulatory commission approval of LDC and EDC customer charges to pay for the new capacity. Furthermore, the 0.642 Bcf/day of Spectra AIM and PNGTS Continent-to-Coast capacity is subscribed by LDCs and therefore completely dependent on gas customer approved rates for their development. Thus, to the extent NEPGA is offering these projects as examples of investor financed projects without the support of regulated rates, that obviously is not the case. Also, as demonstrated by the ICF study attached to Spectra's comments in this investigation and in particular Figure 18, while these and other LDC based pipeline expansion projects will benefit the region throughout their terms they are not sufficiently large to prevent the expected increase in demand for gas from driving prices up over the long term.

NEPGA also makes reference to four major high voltage electric transmission lines each capable of delivering 1,000 MW of clean energy to the region - the Green Line, Northern Pass, the Northeast Energy Link and the New England Clean Power Link – again presumably as examples of market-based energy projects developed in response to market signals and without out-of-market subsidies. However, none of these projects are likely to be implemented absent long-term contracts with regional EDCs.

Finally, regarding the potential role of LNG in mitigating future winter gas and electricity prices, Staff agrees with the implication that the reduction in wholesale energy prices and costs during the 2014/15 winter compared to winter 2013/14 can be attributed in part to increased supplies of lower cost LNG to the region.[73] However, as noted by ISO-NE in its April 2015 review of winter 2014/15 power system performance, "LNG is a globally-priced commodity and its availability in New England is dependent on worldwide demand. New England's record-high natural gas and wholesale energy prices during winter 2013/14, along with high forward prices late last year, provided strong economic signals to LNG suppliers to bring tankers to the region this winter." Unfortunately, there is no guarantee that the same market conditions that enticed tankers to New England in winter 2014/15 will recur in future winters. As ISO-NE concluded in its review, lower LNG supplies in future winters would exacerbate New England's gas pipeline constraints, and heighten the potential for a return to the high wholesale energy prices experienced in winter 2013/14. Furthermore, because the landing price of LNG is unlikely to come close to the price of natural gas in the Marcellus Shale production area, we believe winter electricity prices will continue to reflect sizable basis differentials even when LNG supplies are plentiful. It is for these reasons that Staff does not share NEPGA's view that LNG is a dependable long-term alternative to pipeline expansion for mitigating future winter gas and electricity prices.

UNITIL ENERGY SERVICES AND LIBERTY UTILITIES

Unitil Energy Systems (Unitil) recognizes the key role that natural gas plays in today's regional electric market and that during periods when access to gas becomes scarce wholesale electric prices may become high and volatile. The ideal solution, according to Unitil, is to change regional electric market rules to enable and require gas generators to secure firm access to gas supply but regulatory and political barriers appear to have stalled efforts to implement such rule changes.

However, Unitil does not believe having EDC play the role of counterparty in long term contracts with pipelines is the next best alternative. If EDCs are required to enter contracts to backstop natural gas infrastructure, Unitil contends that other parties who might otherwise decide to contract for pipeline capacity (such as generators and the merchants who supply them) would not do so. State regulators and policy makers should, according to Unitil, exercise patience to see how the electric market responds to over 1 Bcf/day of recently announced pipeline expansion projects before decisions are made on 15 or 20 year commitments by EDCs.[74] In addition to these expansion projects, Unitil contends that there is the prospect of new electric transmission projects which could bring an incremental year-round electric supply to the region, which would reduce the demand for gas and hence gas and electricity market prices.

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[73] The drop in oil prices also helped moderate wholesale energy prices and costs.

[74] The 1 Bcf/day of publicly announced capacity expansions is made up of 0.342 Bcf/day from Spectra's AIM project, 0.072 Bcf/day from TGP's Connecticut Expansion, 0.153 Bcf/day from Spectra's Atlantic Bridge project, and 0.5 Bcf/day from TGP's NED project.

To the extent the Commission directs New Hampshire EDCs to contract for pipeline capacity, Unitil says that no single pipeline project should be presumed to be the best solution. While pipeline demand costs, project viability and access to liquid supplies are critical considerations, maintaining a preference for diversity among projects will improve the likelihood that all or most gas generators will be able to access the additional natural gas supplies.

In the event the states chose to go ahead with a region-wide solution and purchase pipeline capacity under long term contracts with EDCs, Unitil declined to directly answer the question of whether it would voluntarily agree to pay a portion of such capacity costs even if it were not required to contract for capacity. The most Unitil would say was that "it would seem feasible to allocate a share of net capacity costs from an EDC who does contract for pipeline capacity to an EDC that does not." In contrast, Liberty Utilities states that it "would be willing to pay its portion of any region-wide solution that may be implemented provided such costs would be fully recoverable from all of its customers during the period Liberty is obligated to pay for such costs."

Regarding Unitil's contention that the over 1 Bcf/day of publicly announced pipeline expansion projects will meaningfully reduce winter period natural gas prices and in turn wholesale electricity prices, we direct the Commission's attention to ICF's report for Eversource and Spectra on the Access Northeast project. That report, which is discussed above in the section addressing energy cost savings associated with the Access Northeast project, shows in Exhibit 18 that under normal weather conditions and without Access Northeast peak winter gas prices are projected to fall during the 2016 through 2019 period as a direct result of the capacity added by the AIM, Connecticut Expansion and Atlantic Bridge projects. However, from 2019 through 2028 peak winter gas prices are projected to increase due to expected strong growth in the demand for gas for heating and electric generation purposes. Even with Access Northeast, which adds approximately the same amount of capacity as the LDC portion of NED, ICF projects peak winter gas prices to increase throughout the 2019 through 2018 period. In summary, Unitil's instinct that the recently announced pipeline expansion projects will reduce winter period gas and electricity prices is not supported by careful analysis.

STAKEHOLDER MARTIN

Ms. Martin is an active member of the Town of Rindge Energy Commission but notes that her comments in the investigation are not submitted on behalf of any organization, company, lobbying group or special interest.

Unlike many stakeholders in the investigation, Ms. Martin does not subscribe to the view that the root cause of New England's high winter period wholesale and retail electricity prices is caused by a shortage of gas infrastructure. Rather, she seems to hold the view that New Hampshire, and presumably the region, does not have an electricity price problem at all. Her rationale appears to be that the focus on electricity prices is wrong. If the focus was on electric bills, New Hampshire would not have a major problem because it is ranked close to the middle of the pack.

Ms. Martin also believes power generation within the region should be more rather than less diverse. She infers that had the region had a more diverse generation portfolio in the winter of 2013/14, like PSNH and the state of Vermont (which supplies a significant portion of its load with fixed price contracts with non-gas resources that act as a hedge against volatile gas and electricity prices), it would have been better able to withstand the worst of the winter.

The above notwithstanding, the core of Ms. Martin's opposition to an expanded regional pipeline system and more gas generation appears to be her strong belief in and support for more demand response to reduce natural gas demand during the heating season through the use of smart meters and customer incentives; more distributed generation (i.e., behind the meter solar PV systems) made possible by legislative fixes that provide for the expansion of net metering regionally; increased financial support for low income homeowners unable to pay the cost of rooftop solar installations; an expansion of weatherization and energy efficiency programs; and greater development of renewable resources including onshore and offshore wind projects.

Staff does not dispute that energy efficiency and renewable resources have an important role to play in solving the problem of high and volatile electric prices in New England, which we believe is a real problem that many businesses and residences in the region are struggling to overcome. Indeed, the Commission has said on several occasions that there is no single solution to the problem of high electricity prices and that expanded energy efficiency programs, increased importation of Canadian hydroelectricity and increased development of renewable resources can all contribute to mitigating high prices. However, Ms. Martin's suggestion that whatever is ailing the region can be solved with these resources alone does not withstand scrutiny as was clearly demonstrated by the Massachusetts Low Gas Demand Analysis prepared by Synapse Energy Economics in January 2015 for the Massachusetts Department of Energy. Synapse was tasked with answering two key questions:

A. What is the current demand for and capacity to supply natural gas in Massachusetts?
B. If all technologically and economically feasible alternative energy resources are utilized, is any additional natural gas infrastructure needed, and if so, how much?

In order to answer these questions, Synapse evaluated eight scenarios some of which took into account all technically and economically feasible energy efficiency and renewable resources as well as 2,400 MW of incremental Canadian hydroelectric imports. Notwithstanding the inclusion of these alternative energy resources, Synapse found that in order to balance supply and demand for natural gas in Massachusetts in 2020, natural gas pipeline additions that range from 0.6 Bcf/ day to 0.8 Bcf/day were needed. In 2030, the range of required pipeline additions increased slightly to 0.6 Bcf/day to 0.9 Bcf/day. When scaled up to the whole of New England, the equivalent range for 2020 would be 1.1 Bcf/day to1.5 Bcf/day, higher than the 1.1 Bcf/day estimated by ICF in its 2014 Phase II study conducted for ISO-NE.

OTHER STAKEHOLDERS

Many stakeholders chose not to submit concrete solutions and instead focused on related issues such as New Hampshire's historically high energy costs, compared to the rest of the nation, and the damage those costs do residents, businesses, non-profit organizations, and the state's overall economy. BAE Systems, for example, claims that the cost of doing business in New Hampshire is not competitive with other regions of the country, largely because our highest-in-the nation cost of electricity. In terms of actions, some such as the Greater Londonderry Chamber of Commerce urge the Commission to take whatever steps it deems necessary to ensure more affordable sources of energy are available to the state while others like the Business & Industry Association and BAE Systems recommended forging ahead on specific energy infrastructure projects such as pipeline expansion to deliver incremental supplies of natural gas and new electrical transmission lines to transport low cost hydroelectric and wind energy from remote locations. Failure to do so will only deepen and extend the energy crisis and stifle economic growth, says BAE Systems.

Mr. Howard Moffett, a member of the Science, Technology & Energy Committee of the New Hampshire House of Representatives, submitted comments that reflect his own views (rather than those of the Committee) on the causes of and solutions to the high winter period wholesale electricity prices. In summary, Mr. Moffett asserts that there is a strong consensus that the problem is caused by insufficient pipeline capacity feeding the region from west to east and that that consensus is entitled to overwhelming weight. As regards solutions, Mr. Moffett advocates for a region-wide approach that results in the construction of sufficient new gas pipeline capacity to eliminate the "basis differential" but does not see a need for New Hampshire EDC's or their customers to finance the expansion. This, he contends, is the responsibility of LDCs. Also, Mr. Moffett does not see LNG imports as part of the regional solution. LNG prices, he says, are simply too unpredictable and the reliance on more LNG cargoes in future winters would risk regional blackouts.

In the long-term, Mr. Moffett believes the region needs to transition away from fossil fuels and decentralize its electric grid. Achieving these policy goals will require development of a strong Energy Efficiency Resource Standard, the promotion of indigenous renewable energy sources, support for demand response programs, and incentives for distributed generation.

The Office of the Consumer Advocate (OCA), in its initial comments and response to the July 10 Staff Memorandum on legal authorities, took a holistic approach to the question of winter price spikes, and cautioned against market interventions in the first instance. OCA expressed confidence in the ability of the New England energy markets to respond to the price signals being generated, and the benefits of the forthcoming roll-out of ISO-NE reforms such as Pay-for-Performance, in upcoming years. OCA did delineate some criteria for consideration if its preferred course of non-intervention at the market level were not taken: no long-term commitments from rate payers, such as that for pipeline capacity; a resource-neutral approach; a recognition of the benefits of energy efficiency and other demand-side management tools; the need to avoid regulatory duplication across state boundaries and between the federal and state authorities; and the potential benefits of rate smoothing approaches designed to spread out the impact of winter rates for consumers throughout the year. OCA's response to Staff's July 10 Memorandum, as mentioned previously, strongly opposed any conclusion that existing New Hampshire statutory authority existed for the EDCs to acquire pipeline capacity, and also pointed to the issue of potential stranded costs as being a potential ratemaking problem of great concern to OCA.

The New Hampshire Electric Cooperative's (NHEC) primary contribution to the debate over solutions to the high electricity price problem is that for infrastructure projects paid for by consumers, such projects should be chosen and implemented in a manner that minimizes costs to consumers. In this regard, NHEC and other public power systems contend they should be offered the option to participate as equity partners in both pipeline and electric transmission infrastructure projects, allowing the injection of lower cost public power debt financing. Interestingly, Eversource believes that even if such alternative financing mechanisms were feasible, interstate pipelines are unlikely to build infrastructure for others to own, as such activities depart from their established business models of building, owning and operating these facilities for the long term. That said, if this is the price for public power systems agreeing to pay some of the costs of new gas infrastructure projects, Staff urges the representatives of public power systems to make their case to one or more of the project sponsors.

The New Hampshire Pipeline Awareness Network (NHPLAN) contends in its comments that LNG has an important role to play in meeting the peak day demands each winter when "fuel adequacy is seasonably challenged." In support of this position, NHPLAN compared the full cost of the NED pipeline with two LNG storage options; one based on domestically sourced natural gas and the other on LNG imports. Under the pipeline option, NHPLAN calculated a typical annual cost to supply 6 Bcf of gas over 60 winter peak demand days inclusive of gas commodity costs and 365 days of pipeline transportation charges. Under the domestically sourced LNG option, the annual cost comprised the cost to purchase 6 Bcf of natural gas plus the variable cost to liquefy that gas prior to placing it in storage. Under the imported LNG option, the annual cost is simply the product of the 6 Bcf of gas and the landed price of LNG. Based on the results of these calculations, NHPLAN asserts that the LNG alternatives are significantly less costly than purchasing pipeline capacity year round to meet winter peak demands.

Staff, however, contends that NHPLAN's calculations are seriously flawed. While NHPLAN appropriately included fixed pipeline costs in the pipeline option, under the domestically sourced LNG option it excluded the fixed costs associated with storage, liquefaction and vaporization facilities. In addition, it excluded the variable costs of storage and vaporization. As regards the imported LNG option, NHPLAN excluded the fixed costs of the import terminals, the fixed and variable costs of vaporization, and the fixed costs of the pipelines to transport the vaporized gas to gas generators. It also assumed unreasonably that the operator of the facilities would sell the commodity at its landed cost exclusive of margin. For all of these reasons, Staff contends that NHPLAN's assertion is deficient because it is not supported by factual analysis.

National Grid, a joint sponsor of the Access Northeast project, submitted comments that among other things support the idea of EDCs playing the role of counterparties to long-term contracts that enable pipeline construction. National Grid asserts, however, that this role is conditional on the EDCs recovering "total costs (including administrative costs and remuneration) associated with the incremental gas pipeline capacity through a fully reconciling, non-bypassable retail electric cost recovery mechanism." While Staff understands and supports National Grid's position that EDC participation in pipeline construction must be subject to the necessary cost recovery assurances from regulators including the recovery of monthly pipeline demand charges and EDC administrative costs, we question National Grid's insistence that EDCs must also be compensated for the use of their balance sheets.

Our concern relates to the Access Northeast project, which as we have explained includes both Eversource and National Grid as joint sponsors with Spectra. Although the financial details of their partnership with Spectra have not been disclosed, we believe it is reasonable to assume that both parent utility companies will be adequately rewarded for what we think is a relatively low risk undertaking. We base this assumption on ICF's estimate that a $2.4 billion capital investment will produce a levelized annual cost of $400 million assuming a 20-year contract term. That is, electric consumers would pay $8.0 billion over the life of the contract. We estimate that about one quarter of those revenues could be retained by the project partners as profit, while the rest would cover depreciation expenses, debt costs, and income and property taxes. While Staff acknowledges that the willingness of the EDCs to take on the role of counterparty in the long-term contracts exposes them to some financial risk, we believe that risk is small given the cost recovery assurances they are seeking. For these reasons, we urge the Commission to reject any request for such remuneration related to the Access Northeast project.

That said, Staff believes there may be a case for EDC compensation whenever long-term capacity contracts are entered into with TGP or PNGTS projects.

The Office of Energy and Planning (OEP) sent in initial comments setting out the proposition that another Commission docket, that in IR 14-338 related to rate smoothing, should be combined with this Investigation, that an expert should be retained to assist Staff in its Investigation, and that "OEP cautions the PUC against attempting to address wholesale issues on its own."

COMPETITIVE SELECTION PROCESS

Sponsors of new or expanded natural gas pipelines generally employ open seasons to determine market interest in their projects. An open season is a process by which the sponsor of a pipeline project solicits prospective natural gas customers to bid on the available transportation capacity, evaluate the bids submitted, and award or allocate the capacity among customers that have met the qualification requirements. As a result of this process, project sponsors and selected customers typically enter into binding or non-binding precedent agreements that specify, among other things, the amount of transportation capacity to be purchased and the rates to be paid per unit of firm transportation. It is common practice for project sponsors and potential customers to negotiate the rates that customers pay for pipeline services, although the pipelines also must make available FERC-approved cost-based recourse rates that can be used in the event negotiations prove unsuccessful.

Access Northeast completed an open season May 1, 2015 and executed memoranda of understanding[75] with three EDC affiliates of National Grid and four EDC affiliates of Eversource, which together account for approximately 71 percent of the retail electric load in New England. As explained above, National Grid and Eversource are two of the three sponsors of the Access Northeast project and therefore the affiliated EDCs are not disinterested observers.[76] In addition, the sponsors of Access Northeast have also had discussions with unaffiliated New England ECDs to gauge their interest in participating in the project with the goal of spreading the project fixed costs more broadly. The outcome of those discussions has not been shared with Staff.

NED has completed an open season for New England LDCs and executed precedent agreements with nine companies for a total firm transportation capacity of approximately 0.55 Bcf/day on the Market Path segment, leaving approximately 0.75 Bcf/d of additional capacity available for EDCs. On September 9, 2015 TGP began a second open season for EDCs only. Finally, PNGTS has made it known that it expects to hold an open season for its new expansion project in the 4th Quarter of 2015 or the 1st Quarter of 2016.

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[75] It is important to note that the MOUs were entered into prior to EDCs meeting with the sponsors of competing pipeline projects. Furthermore, Eversource declined to provide Staff with a copy of the MOU executed with PSNH, claiming its terms contain commercially sensitive information that must remain undisclosed while precedent agreements are under negotiation. The key terms of a precedent agreement typically include the amount of capacity to be purchased, the rates for firm transportation, and the term of the contract.

[76] Although Access Northeast has been marketed to electric (rather than gas) distribution companies, Eversource been quoted in the press as saying that the project has also received strong interest from LDCs and that the company has started the process of negotiating long-term contracts with those companies. The implications of this development are addressed elsewhere in this report.

Despite the significant work done by project sponsors in organizing and hosting the open seasons, and by the participating EDCs in evaluating the various projects, Staff strongly recommends that if the New England states decide as a group to proceed with the procurement of incremental pipeline capacity on a regional basis that procurement not be based on the results of open seasons. Given that the capacity purchased by EDCs will be paid for by the customers of those companies and not the shareholders, Staff believes that it is incumbent on regulators to ensure that the target capacity be allocated among pipeline projects without favor through an open and transparent process that is demonstrably competitive and results in the lowest possible cost to consumers. As long as a significant number of the New England EDCs are affiliated with the sponsors of one of the competing pipeline projects, we believe it will be difficult if not impossible for EDCs to make a convincing case that pipeline open seasons qualify as fair, open and transparent competitive processes. For this reason, we believe it is imperative that the states develop and post for comment an alternative competitive solicitation process (i.e., Request for Proposals ("RFP")) much like the three southern New England states did when they developed a joint Clean Energy RFP. As is the case here, the purchasers of clean energy products will include New England EDCs that are affiliated with sponsors of one or more of the projects that are expected to submit bids. However, unlike the Clean Energy RFP, we do not believe it would be appropriate to have the EDCs play a significant role in the development of the RFP or in evaluating the bids. In Staff's opinion, the terms and conditions for the pipeline capacity RFP including the criteria for evaluating the bids should be the responsibility of the states assisted by an independent consulting firm with extensive expertise in gas and electricity procurement matters. Such independent consultant could also play the important role of primary bid evaluator. As CLEC correctly observes in its comments, the procurement of pipeline capacity "is a fundamentally public decision" that should not be delegated to EDCs and certainly not EDCs that have corporate relationships with project sponsors, and thus are likely to be burdened with conflicting interests.

The pipeline capacity RFP should be issued on behalf of New England EDCs that volunteer to participate in the procurement of incremental capacity and should solicit bids for firm transportation services from pipeline developers that offer such services. We anticipate that the aggregate amount of pipeline capacity to be purchased would be decided by the New England states through a collaborative effort, but hopefully somewhat less than the aggregate capacity of Access Northeast and NED projects in order to maximize the competitive pressures on bidders to offer their best prices. The RFP should also request binding bids on the ground that if developers are not held to their bids, the competitive process loses its integrity. Non-binding bids or bids with cost overrun provisions should be discouraged. In addition, the designers of the RFP may wish to consider requesting bids for relatively small increments of capacity that sum to the agreed aggregate amount in order to eliminate the problem of evaluating bids for projects of different sizes. Finally, requiring the competitive solicitation process to be transparent, thorough and overseen by independent evaluators will promote robust competition among pipeline sponsors to the ultimate benefit of consumers. Absent a demonstrably competitive solicitation, Staff foresees a significant risk that the negotiations between a project sponsor and potential customers will not be at arms-length and thus will not produce the most advantageous cost and commercial terms for consumers.

As regards the criteria for bid evaluation, we agree with CLEC that an important criterion is price. And by price we mean the delivered price of natural gas. Gas infrastructure projects, whether pipeline or LNG based, should be graded primarily on the basis of the delivered price of gas. This, however, raises the difficult question of how to determine in the context of an RFP the average price of gas at a specific receipt point over a 15- to 20-year contract term. While current market conditions may indicate some receipt points can access lower cost gas than others, those conditions are likely to change over time making such comparisons unreliable. Perhaps the best an evaluator can do is assume that market forces will eliminate over time any price differential between receipt points, which leads to the conclusion that the evaluation of competing projects should be based in large part on the rates for firm transportation service. That is, projects with lower transportation rates should be ranked higher than projects with higher transportation rates, all other things being equal. For projects with multiple transportation rates, we recommend that the weighted average rate be used for evaluation purposes.

There is, however, another criterion that some may argue should be ranked as high as the level of transportation rates in the evaluation process and that is a project's benefit to cost ratio. While pipeline capacity increments of the same size should produce the same wholesale energy cost savings, the cost to implement and hence the benefit to cost ratio may differ if, for example, a portion of the construction cost is allocated to LDCs rather than EDCs. This allocation of costs to LDCs should, however, enable the project sponsor to bid a lower transportation rate. Thus, in a truly competitive solicitation process, the relative firm transportation rates should determine in large part which projects are awarded capacity contracts.

Additional weight could be given to pipeline capacity proposals that can be readily expanded through the addition of compression or similar incremental investments – as opposed to replacement of actual pipe. Further, since delays in pipeline in-service dates are extremely costly to electricity consumers, additional weight could be given to pipeline capacity proposals that have realistic earlier in-service dates.

Finally, Staff anticipates that capacity purchased from pipeline projects based on a demonstrably competitive solicitation process would be allocated among participating EDCs (potentially including municipal and cooperative utilities) on a pro-rate load share basis. The EDCs would then engage in negotiations with the winning projects and execute precedent agreements for pipeline transportation service, which would become effective only after regulatory review and approval.

REGULATORY APPROVAL PROCESS

Any New Hampshire EDC that chooses to purchase capacity under one or more infrastructure projects would be responsible for seeking Commission approval of its capacity purchases, assuming of course the Commission must determine that New Hampshire EDCs have the legal authority to enter into long-term contractual arrangements to benefit their customers. Capacity purchased on the basis of a demonstrably competitive solicitation process should be regarded by the Commission as satisfying any statute or regulation requiring the use of least cost procurement practices, meaning that the winning bids will be those that provide the highest value to electricity consumers. This does not mean, however, that capacity contracted by EDCs is necessarily in the public interest. In order to meet that standard, we believe each EDC seeking regulatory approval of its contract must establish that the associated wholesale energy cost savings will exceed by an appropriate margin the costs of the purchase. To meet this burden, we anticipate that each EDC or the EDCs as a group will need to hire the services of a consulting firm with extensive experience in gas industry modeling.

Base Case – LNG Priced at $14/mmbtu

Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers

Pipeline Capacity	Pipeline Capacity bcf/d	Hours of Generation by Fuel Type LNG	Propane	Oil
Base Case	3,136	2113	374	296
+ 0.2 bcf/d Capacity	3,336	1723	267	217
+ 0.4 bcf/d Capacity	3,536	1316	198	158
+ 0.6 bcf/d Capacity	3,736	993	144	120
+ 0.8 bcf/d Capacity	3,936	750	104	78
+ 1.0 bcf/d Capacity	4,136	550	71	56
+ 1.2 bcf/d Capacity	4,336	391	53	46
+ 1.4 bcf/d Capacity	4,536	288	41	35
+ 1.6 bcf/d Capacity	4,736	206	34	28
+ 1.8 bcf/d Capacity	4,936	152	27	22
+ 2.0 bcf/d Capacity	5,136	111	17	12
+ 2.2 bcf/d Capacity	5,336	74	11	9
+ 2.4 bcf/d Capacity	5,536	54	7	6

Pipeline Capacity	Annual Energy Costs ($)	Incremental Savings ($)	Cumulative Savings ($)	Load Weighted Avg. Energy Price ($/MWh)
Base Case	$7,683,828,621			$60.38
+ 0.2 bcf/d Capacity	$7,196,238,670	$487,589,951	$487,589,951	$56.55
+ 0.4 bcf/d Capacity	$6,662,968,905	$533,269,765	$1,020,859,716	$52.36
+ 0.6 bcf/d Capacity	$6,215,782,492	$447,186,412	$1,468,046,128	$48.84
+ 0.8 bcf/d Capacity	$5,862,015,565	$353,766,927	$1,821,813,055	$46.06
+ 1.0 bcf/d Capacity	$5,556,608,801	$305,406,764	$2,127,219,819	$43.66
+ 1.2 bcf/d Capacity	$5,302,503,435	$254,105,366	$2,381,325,185	$41.67
+ 1.4 bcf/d Capacity	$5,129,825,208	$172,678,227	$2,554,003,412	$40.31
+ 1.6 bcf/d Capacity	$4,986,336,567	$143,488,641	$2,697,492,053	$39.18
+ 1.8 bcf/d Capacity	$4,887,791,007	$98,545,560	$2,796,037,613	$38.41
+ 2.0 bcf/d Capacity	$4,809,857,588	$77,933,420	$2,873,971,033	$37.80
+ 2.2 bcf/d Capacity	$4,737,106,541	$72,751,047	$2,946,722,080	$37.22
+ 2.4 bcf/d Capacity	$4,696,129,285	$40,977,255	$2,987,699,335	$36.90

LNG Priced at $10/mmbtu

Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers

Pipeline Capacity	Pipeline Capacity bcf/d	Hours of Generation by Fuel Type LNG	Propane	Oil
Base Case	3,136	2113	374	296
+ 0.2 bcf/d Capacity	3,336	1723	267	217
+ 0.4 bcf/d Capacity	3,536	1316	198	158
+ 0.6 bcf/d Capacity	3,736	993	144	120
+ 0.8 bcf/d Capacity	3,936	750	104	78
+ 1.0 bcf/d Capacity	4,136	550	71	56
+ 1.2 bcf/d Capacity	4,336	391	53	46
+ 1.4 bcf/d Capacity	4,536	288	41	35
+ 1.6 bcf/d Capacity	4,736	206	34	28
+ 1.8 bcf/d Capacity	4,936	152	27	22
+ 2.0 bcf/d Capacity	5,136	111	17	12
+ 2.2 bcf/d Capacity	5,336	74	11	9
+ 2.4 bcf/d Capacity	5,536	54	7	6

Pipeline Capacity	Annual Energy Costs ($)	Incremental Savings ($)	Cumulative Savings ($)	Load Weighted Avg. Energy Price ($/MWh)
Base Case	$6,358,806,914			$49.97
+ 0.2 bcf/d Capacity	$6,071,331,989	$287,474,925	$287,474,925	$47.71
+ 0.4 bcf/d Capacity	$5,762,959,523	$308,372,466	$595,847,391	$45.28
+ 0.6 bcf/d Capacity	$5,505,725,096	$257,234,427	$853,081,818	$43.26
+ 0.8 bcf/d Capacity	$5,302,777,297	$202,947,799	$1,056,029,617	$41.67
+ 1.0 bcf/d Capacity	$5,128,848,329	$173,928,969	$1,229,958,586	$40.30
+ 1.2 bcf/d Capacity	$4,984,670,631	$144,177,697	$1,374,136,283	$39.17
+ 1.4 bcf/d Capacity	$4,886,506,519	$98,164,112	$1,472,300,395	$38.40
+ 1.6 bcf/d Capacity	$4,805,074,015	$81,432,504	$1,553,732,900	$37.76
+ 1.8 bcf/d Capacity	$4,748,977,913	$56,096,101	$1,609,829,001	$37.32
+ 2.0 bcf/d Capacity	$4,704,714,006	$44,263,907	$1,654,092,908	$36.97
+ 2.2 bcf/d Capacity	$4,663,784,289	$40,929,717	$1,695,022,625	$36.65
+ 2.4 bcf/d Capacity	$4,640,646,097	$23,138,192	$1,718,160,817	$36.47

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

IR 15-124

ELECTRIC DISTRIBUTION UTILITIES

Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire

Order Accepting Staff Report and Stakeholder Comments, and Outlining Review Process for Any Petitions for Capacity Acquisitions and Associated Competitive Bidding

O R D E R N O. 25,860

January 19, 2016

I. BACKGROUND

On April 17, 2015, the Commission issued an Order of Notice announcing an investigation, pursuant to RSA 365:5, RSA 374:3 and :4, and RSA 374-F:8, into potential approaches involving New Hampshire's electric distribution utilities (EDCs) to address cost and price volatility issues affecting wholesale electricity markets in New Hampshire. In general terms, the Commission ordered the Commission Staff (Staff) to prepare a report regarding the natural gas resource constraint issues facing the New England electricity market to be filed no later than September 15, 2015. A report by Commission Staff was filed as ordered on September 15, 2015, under the direction of Electric Division Assistant Director George McCluskey (Staff Report).[1] In advance of the Staff Report's filing, Staff engaged in a series of collective stakeholder meetings with interested persons and organizations, including the three New Hampshire EDCs, and also met bilaterally with certain stakeholders to clarify their proposals for resolving gas constraint issues and related data responses. This process resulted in a large volume of written materials, including bilateral data requests and responses between Staff

[1] The Staff Report is available here: http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-124/LETTERS-MEMOS-TARIFFS/15-124%202015-09-15%20STAFF%20REPORT.PDF

and certain stakeholders, which are posted for public inspection on the Commission's website at: http://www.puc.nh.gov/Electric/Investigation_into_Potential_Approaches_to_Mitigate_Wholesale_Electricity_Prices.html. Also, the Commission granted leave for interested persons to file comments directly with the Commission regarding the Staff Report by October 15, 2015. Those comments are posted at: http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-124.html

II. ACCEPTANCE OF STAFF REPORT AND STAKEHOLDER COMMENTS

The Staff Report is an overview of the natural-gas capacity constraints in the New England energy market from a multi-disciplinary perspective: economic, legal, financial, engineering, and environmental. Interested persons are urged to read the Staff Report and the other primary-source materials generated by Staff and stakeholders through this investigation to inform themselves of the issues at hand. We will not attempt to condense or summarize the broad scope of material available for public inspection, or distill the many varied perspectives presented by Staff and stakeholders. With one exception (discussed below), the Commission will also not make judgments at this time regarding the factual content and policy positions outlined in the Staff Report, the submissions by the various stakeholders, and the data requests/responses available for inspection. That said, it is clear that Staff engaged in a thorough analysis of the questions presented in the Order of Notice and the factual information at its disposal. The Commission will therefore accept the Staff Report as compliant with the directives set out by the Commission for the investigation in Docket No. IR 15-124, and accept the companion stakeholder comments.

III. FUTURE REVIEW PROCESS FOR GAS CAPACITY-RELATED PETITIONS

The Staff Report indicated that, in Staff's view, there exists a path under New Hampshire law for the approval of acquisitions of natural gas capacity resources by New Hampshire EDCs for the economic benefit of their customers and the customers of other regional EDCs. *See* Staff Report at 9-13. As indicated by their comments, this position was accepted by certain stakeholders and opposed by others. It is clear to the Commission, from a review of the Staff Report, stakeholder comments, and ancillary materials made publicly available through this investigation, that no consensus exists regarding the potential legality of such an acquisition of gas capacity by a New Hampshire EDC. Furthermore, we expect that such a capacity acquisition would be highly controversial.

The Commission thus intends to rule on the question of whether a New Hampshire EDC has the legal authority to acquire natural gas capacity resources to positively impact electricity market conditions, only within the context of a full adjudicative proceeding conducted pursuant to the New Hampshire Administrative Procedure Act, RSA Chapter 541-A, and only in response to an actual (as opposed to hypothetical) petition. Such a proceeding would be opened if and when a New Hampshire EDC files a petition for a proposed capacity acquisition, and related cost recovery. The Commission would consider the petition in separate phases. In the first phase, the Commission would review briefs submitted by the petitioner EDC, Staff, and other parties regarding whether such capacity procurement is allowed under New Hampshire law. If the Commission were to rule against the legality of such acquisition, the petition would be dismissed. If the Commission were to rule in the affirmative regarding the question of legality, it would then open a second phase of the proceeding to examine the appropriate economic, engineering, environmental, cost recovery, and other factors presented by the actual proposal. This second phase would involve the usual procedural features of discovery, testimony, rebuttal testimony, and cross-examination, provided in any adjudicative proceeding before the Commission.

IV. EXPECTED COMPETITIVE BIDDING FOR CAPACITY

As is clear from the Staff Report and the extensive comments filed in this docket, there is no New Hampshire precedent for EDCs to purchase gas pipeline capacity for electric generators. That is different from the situation with local gas distribution companies (LDCs) which sell gas on the retail market. An essential part of an LDC's business is the procurement of gas supply for its customers. In New Hampshire, our two gas LDCs are required to file Least Cost Integrated Resource Plans under RSA 378:37 *et. seq.* that lay out how they expect to fulfill their obligations to customers. It is not unusual for an LDC to make a firm commitment to purchase capacity on a gas pipeline. The LDCs know they must follow appropriate competitive processes for their gas supply and capacity purchases. Each such procurement is subject to scrutiny to make sure that the decision is consistent with prudent utility practice.

As indicated, the Commission is not going to rule on substantive questions at the present time regarding the legality or specific attributes of a natural gas capacity related procurement. Nonetheless, due to the practicalities of private-sector contracting for such capacity taking place in advance of petitions for regulatory approval, the Commission will outline one policy directive to EDCs and stakeholders related to the terms under which such acquisitions would be made. Under the Commission's Affiliate Transactions Rules, N.H. Code Admin. Rules, Chapter Puc 2100, there exists a strong policy preference against self-dealing in relations between New Hampshire EDCs and their unregulated affiliates.

Functionally, this would tend to militate against the use of a sole-source acquisition approach by a New Hampshire EDC seeking to only acquire a gas capacity product from its competitive, unregulated affiliate. Also, there is a recognition in private industry and regulatory bodies throughout the United States that competitive bidding acquisition processes provide powerful benefits for ensuring prudency in utility expenditure and, by extension, cost savings for utility customers, through the introduction of cost discipline, open participation by competitors, and choices in product acquisition. Those benefits were identified in the Staff Report, which strongly advocated in favor of requiring that any gas capacity acquisition program by a New Hampshire EDC be predicated on competitive evaluation and selection processes undertaken by entities unaffiliated with the project sponsors. Staff Report at 11-12, and 46-47. We agree. The Commission expects that any acquisition of gas capacity by a New Hampshire EDC for the ultimate benefit of electric customers would be undertaken through an open, transparent, and competitive bidding/Request for Proposals (RFP)-type process, in which competitors of the New Hampshire EDC's corporate affiliates or business partners would also be able to participate. Furthermore, this competitive solicitation process should be open to all categories of gas capacity product, including pipeline, Liquified Natural Gas, and Compressed Natural Gas capacity. It would also include storage solutions to ensure maximal choice and potential cost savings. In addition, in recognition of various state gas capacity procurement efforts occurring throughout the New England region, the Commission would accept a New Hampshire EDC's participation in another state's RFP platform where the evaluation and selection of competing projects is the responsibility of entities that have no affiliation with any of the project sponsors.

V. CONCLUSION

The Commission wishes to thank the Staff for its hard work during this investigation, and for the preparation of the Staff Report and ancillary materials. The Commission also extends its appreciation for the various stakeholders' engagement with this process, for their comments, and for their ongoing interest in this matter of great importance to our State.

Based upon the foregoing, it is hereby

ORDERED, that the Staff Report and companion stakeholder comments in this instant investigation are ACCEPTED, and that future petitions for gas capacity acquisition programs be governed by the policy approaches outlined in this Order.

By order of the Public Utilities Commission of New Hampshire this nineteenth day of January, 2016.

Martin P. Honigberg
Chairman

Kathryn M. Bailey
Commissioner

Attested by:

Debra A. Howland
Executive Director

September 28. 2016 6:53PM

New England's energy situation 'precarious,' ISO leader says

By ELI OKUN
Union Leader Correspondent

(/storyimage/UL/20160929/NEWS05/160929147/AR/0/AR-160929147.jpg?q=100)

Gordon van Welie, president and CEO of ISO New England Inc., addresses the audience. (ELI OKUN/UNION LEADER CORRESPONDENT)

GOFFSTOWN — Energy supplies, reliability and cost are concerns for many New Englanders. But they don't inspire insomnia in many.

As president and CEO of ISO New England Inc., however, Gordon van Welie has more reason to be kept up at night than most. ISO-NE oversees the region's power system.

"I really do think we're facing some choices in the region," he said Wednesday afternoon, "some crossroads or forks in the road that we'll have to figure out which one we want to take."

Van Welie's remarks came at a discussion of New England's power markets and infrastructure, hosted by the New England Council at Saint Anselm College's New Hampshire Institute of Politics.

And he was blunt about the seriousness of the challenges, many of which lack easy solutions, that are looming for the region in just a matter of years. Van Welie said New England's current operating situation is precarious, and it could become unsustainable in extreme cold weather after 2019.

"The ISO does not use words like precarious or unsustainable lightly," said Peter Howe, a former longtime reporter for the Boston Globe and New England Channel News who moderated the conversation. "Take that seriously."

If New Hampshire and other local states are in danger of having the lights turn off during a cold snap in just four years, what can be done now?

The answers are not so simple, van Welie said.

Many coal and oil generators have been retired in recent years, and that trend will only continue as more renewable energy quickly comes online, he said. And demand is expected to remain roughly flat over the next decade.

But ensuring adequate supply should be a top priority, Van Welie said. Without sufficient storage mechanisms, the reliability of renewable energy can be variable and dependent on the weather.

At the center of New England's energy challenge lie two potentially competing aims, van Welie said: achieving energy reliability through the competitive wholesale market, as the system's framework is set up currently, and reducing carbon emissions. Though the latter goal is a crucial environmental priority, policy steps to achieve it have the potential to disrupt the market structure.

Van Welie said that personally, he views carbon pricing as one sensible solution — and one that seems likely for the United States in the long term. "A lot of the fear is dissipating around carbon pricing amongst asset owners," he said, adding that even Capitol Hill seems to be warming somewhat to the idea.

In New England, many of the states support carbon pricing — but having all six onboard would make the Federal Energy Regulatory Commission more inclined to approve such a filing from ISO, he said.

In response to a question from the crowd of more than 100, van Welie said he thinks the Seabrook Station Nuclear Power Plant and the Millstone Nuclear Power Plant in Waterford, Conn., are likely to remain online at least in the short term.

Van Welie lauded the efforts of the New England Power Pool, which has started a stakeholder process to try to figure out possible market adjustments and solutions for the region's energy and environmental objectives. The group is releasing a framework document by early December, working with ISO and others in 2017 to formulate a plan.

Whatever the ultimate solution, van Welie added, something has to be done. "A decision not to act is going to also be a decision," he said.

ISO new england

PRESS RELEASE

FOR IMMEDIATE RELEASE

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ISO New England: Managing Reliable Power Grid Operations This Winter

Supplies should be sufficient—barring unexpected resource outages or fuel delivery constraints

Holyoke, MA—December 5, 2016—Electricity supplies should be sufficient to meet New England's consumer demand for electricity this winter, according to ISO New England, the operator of the region's power system. Because possible natural gas pipeline constraints could limit electricity production from natural gas power plants, ISO New England has implemented a Winter Reliability Program that will help protect overall grid reliability.

"Reliable power system operations depends on sufficient resources, adequate fuel supplies, and available infrastructure for both fuel and electricity delivery," said Vamsi Chadalavada, executive vice president and chief operating officer of ISO New England Inc. "The region should have adequate supplies of electricity to meet demand, barring any unforeseen resource outages or fuel delivery constraints."

Managing Multiple Risks

Winter has become a challenging time for New England grid operations, especially during the coldest weeks of the year when the availability of natural gas supplies is uncertain. Approximately 44%—about 14,850 megawatts (MW)—of the total generating capacity in New England uses natural gas as its primary fuel, and natural gas generated 49% of the region's power in 2015. New England's natural gas infrastructure was not designed to serve demand for natural gas for both heating and power generation, so on cold winter days, New England's network of pipelines is near or at capacity for commercial and residential heating. Any pipeline capacity remaining after heating customers are served can be sold for power generation. As a result, approximately 3,450 MW of natural-gas-fired generating capacity may be at risk this winter because of pipeline constraints.

This year, the completion of the Algonquin Incremental Market (AIM) Project will increase pipeline capacity into the region by 342,000 dekatherms of gas per day and is expected to ease concerns about pipeline capacity this winter. However, in coming years, Local Distribution Companies (LDCs)—that sell gas to heating customers—will continue to expand their infrastructure and use this increased capacity. Moreover, the region will lose 1,500 MW of coal- and oil-fired generation this spring that will be replaced primarily by new gas-fired generation, and no additional infrastructure to deliver or store natural gas is currently being developed. Also, New England has relied on cargoes of liquefied natural gas (LNG) in recent winters, but these LNG tankers follow global market spot prices and may elect to go elsewhere, depending on price. They can also be held up by severe weather in winter.

2016/2017 Winter Reliability Program

To help address these multiple risks, ISO New England will again use a Winter Reliability Program to incentivize gas and oil-fired power plants to procure sufficient fuel before winter begins. The program will run from December 1, 2016 to February 28, 2017, and include an oil inventory component, an LNG component, and a demand response component.

According to Chadalavada, "Despite planning for these anticipated risks, if the region experiences any combination of extreme cold for an extended time, power plant outages, and limitations on natural gas delivery, maintaining reliability could require the use of emergency procedures. Beyond this winter, the situation will grow even more uncertain because non-gas power plants are retiring and being replaced primarily with new, gas-fired generation. We are currently evaluating how the ISO will maintain reliability in the future under these conditions."

The next non-gas generator to retire will be the 1,500 MW Brayton Point Power Station in Massachusetts that will close at the end of May 2017.

2016/2017 Winter Outlook by the Numbers

- Peak demand forecast:
  - At normal winter temperatures of about 7 degrees Fahrenheit (°F): **21,340 megawatts (MW)**
  - If extreme winter weather of 2°F occurs: **22,028 MW**
  - Both forecasts take into account the **1,884 MW** in energy savings from energy-efficiency measures acquired through the region's Forward Capacity Market (FCM)
- Resources with an FCM capacity supply obligation to be available: **31,101 MW**
  - Total resources, including both FCM obligations and capability without FCM obligations: **33,948 MW** (A generator's maximum possible output may be greater than its FCM obligation)
- Natural-gas-fired generating capacity at risk of not being able to get fuel when needed: **3,450 MW**
- Winter 2015/2016 peak demand: **19,545 MW** on February 14, 2016, for the hour from 6 to 7 p.m.
- All-time winter peak in New England: **22,818 MW** on January 15, 2004
- All-time peak demand: **28,130 MW**, on August 2, 2006

Operational Procedures to Maintain Reliability

Should unexpected generator or transmission line outages occur, the ISO has procedures in place to maintain reliability, including calling on demand-response resources to reduce their energy use, importing emergency power from neighboring regions, and asking businesses and residents to voluntarily conserve electricity.