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October 15, 2015

Debra Howland
Executive Director
New Hampshire Public Utilities Commission
215 Fruit Street, Suite 10
Concord, NH 03301

Re: **Comments of Algonquin Gas Transmission, LLC and Spectra Energy Partners, LP**

Dear Ms. Howland:

Please find attached comments of Algonquin Gas Transmission, LLC and Spectra Energy Partners, LP in the above-referenced docket. Please do not hesitate to contact me if you have any questions or require additional information.

Sincerely,

Emilee Mooney Scott

Emilee Mooney Scott

Copy to: Service List

**BEFORE THE NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION**

INVESTIGATION INTO POTENTIAL	:	
APPROACHES TO MITIGATE	:	DOCKET NO. IR 15-124
WHOLESALE ELECTRICITY PRICES	:	

**COMMENTS OF ALGONQUIN GAS TRANSMISSION, LLC
AND SPECTRA ENERGY PARTNERS, LP**

Algonquin Gas Transmission, LLC and Spectra Energy Partners, LP (collectively, "Spectra Energy"), as co-developers[1] of the Access Northeast Project ("Access Northeast"), hereby submit comments in response to the Report on Investigation into Potential Approaches to Mitigate Wholesale Electricity Prices in the above-referenced matter ("Staff Final Report")[2] prepared by the Staff of the New Hampshire Public Utilities Commission ("NHPUC" or the "Commission").[3]

EXECUTIVE SUMMARY

The inadequate supply of natural gas to New England's natural gas-fired electric generators causes electric consumers in New Hampshire to face high and volatile electric prices, particularly in the winter. Recognizing these issues, the Commission directed Staff to undertake an investigation to "examine the gas-resource constraint problem" and identify potential

[1] Eversource Gas Transmission LLC, a subsidiary of Eversource Energy, National Grid Algonquin LLC, a subsidiary of National Grid USA, Spectra Energy Corp., and Spectra Energy Partners, LP are working to develop the Access Northeast Project.

[2] Report on Investigation into Potential Approaches to Mitigate Wholesale Electricity Prices (Sept. 15, 2015).

[3] Spectra Energy wishes to acknowledge the diligent efforts of Staff to elicit, accept, and synthesize comments from interested stakeholders in this investigation.

solutions to such problem.[4] After completing its analysis, Staff issued its Final Report. Spectra Energy supports Staff's position that electric distribution companies ("EDCs") could be permitted under New Hampshire statute[5] to contract with the natural gas pipelines for natural gas pipeline capacity and that such contracts may be evaluated using established mechanisms and standards for evaluation.[6] Spectra Energy submits, however, that time is of the essence, and that existing procedures provide abundant checks and balances, which militates in favor of a more streamlined process rather than the formal solicitation or request for proposals ("RFP") process recommended by Staff. Spectra Energy further urges the Commission to consider the full measure of project costs and benefits (including "last mile" delivery) and, to the extent directly comparing projects, to base such comparisons on truly comparable data.

The Problem: High And Volatile Electric Prices In New Hampshire Are Caused By Inadequate Natural Gas Supply To The Electric Power Generators.

High and volatile electric prices will persist as long as electric power generators continue to hold minimal to no firm transportation on the Algonquin Pipeline ("Algonquin") and other natural gas pipelines directly serving the generators. Further, natural gas-fired generators have not participated in recent expansions, and, consequently, Algonquin and pipelines in general are not designed (as of yet) to serve electric power generators. Those projects currently planned and moving forward are designed to serve traditional natural gas local distribution company ("LDC") demand, not electric power generation.

High natural gas prices lead immediately and directly to high wholesale electricity prices, as New England increasingly relies on natural gas-fired electric power generators to supply

[4] Docket No. IR 15-124, Order of Notice (Apr. 17, 2015).

[5] Staff Final Report, at 10.

[6] *Id.* at 12.

power to the grid. Today (October 15, 2015) natural gas is supplying seventy percent (70%) of New England's electric generation, which is only possible given mild temperatures and associated modest heating needs.[7] But given that natural gas-fired units hold minimal to no firm transportation on the pipelines to which they are connected, they must rely on interruptible or secondary services that are not available during peak capacity periods when generators need it most. In fact, in 2012 through 2015, the Algonquin pipeline has operated at high utilization, with no interruptible capacity available, virtually every day of the year.[8]

During periods when natural gas-fired generators cannot obtain sufficient natural gas, the marginal unit(s) setting electric prices will be one(s) that rely on higher cost and less environmentally sound fueling resources (*e.g.*, oil, coal). Because ISO New England ("ISO-NE") operates New England's power system as a unified grid, New Hampshire electric consumers face prices that are shaped by natural gas constraints throughout New England, not just supply to New Hampshire generators. Lower electric prices for New Hampshire electric consumers can only be ensured by a solution that delivers natural gas ***directly where it is needed*** to serve electric power generators. Over sixty percent (60%) of New England's natural gas-fired electric generation is already ***directly connected*** to the existing Algonquin and Maritimes pipeline systems, both of which will have their capacity enhanced through the Access Northeast project.

The retirement of coal, oil and nuclear-powered generators will increase the demand for natural gas and place further pressure on the already constrained system. Just this week, Entergy

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[7] ISO-NE, Fuel Mix Chart (Oct. 15, 2015) (available at: http://www.iso-ne.com/isoexpress/web/charts).

[8] See Attachment 1.

announced its planned retirement of the 680 MW Pilgrim Nuclear Power Station ("Pilgrim").[9] Nuclear power generated thirty-four percent (34%) of New England's electricity in 2014, but Entergy's 620-MW Vermont Yankee nuclear power plant retired in December 2014 and now Pilgrim is slated to retire in 2019.[10] Taken together, recent and pending retirements (including Pilgrim), will total nearly 4,200 MW between 2014 and 2019.[11] As ISO-NE highlighted in its response to the Pilgrim retirement:

> New England has limited natural gas pipeline infrastructure serving the region. The availability of natural gas for power generation has an impact on grid reliability, especially during the winter months when gas pipelines have reached maximum capacity to heat homes and businesses, or during other times of the year when gas pipelines are out of service for maintenance.[12]

In this environment, it is especially critical that New England be timely supplied with adequate natural gas resources for electric power generation.

Any pipeline proposal that purports to address peak electric power fuel needs for a generator in New Hampshire or regionally by indirectly delivering to another pipeline (without firm commitments on these other pipelines) does not achieve the regional solution New Hampshire and New England need for power price mitigation. In fact, any solution that does not increase Algonquin's capacity will mean that those generators directly connected to Algonquin (which together with Maritimes represents sixty percent (60%) of all natural gas-fired generating capability in New England) will still rely on the same third party interruptible or secondary

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[9] Press Release, Entergy Corporation, Decision driven by low energy prices, little expectation of near-term market structure improvements and increased operational costs (Oct. 13, 2015) (available at: http://www.pilgrimpower.com/entergy-to-close-pilgrim-nuclear-power-station-in-massachusetts-no-later-than-june-1-2019/).

[10] Press Release, ISO-NE, ISO New England's Response to Pilgrim Nuclear Power Plant Retirement Request (Oct. 13, 2015) (available at: http://www.iso-ne.com/static-assets/documents/2015/10/20151013_pilgrim_retirement_request.pdf).

[11] *Id.*

[12] *Id.*

transportation that generators have always relied upon. An LDC with firm contracts on that third party pipeline is still going to need its gas on coldest days and as recent winters have demonstrated, will not release its firm capacity to the generator who needs it to run. As a consequence, high power prices will remain. Anything less than a "last mile" solution is analogous to saying that traffic is flowing well in a given city after a heavy snowstorm if Interstate 89 has been plowed but Interstates 93 and 95 and city streets are untouched and unable to carry regional or local traffic.

The Solution: Access Northeast Provides Firm Natural Gas Capacity To The Region's Critical Natural Gas Generators.

Access Northeast maximizes energy savings to the region by addressing the region's "last mile" infrastructure problem (and the "last mile" shorthand refers to a distance that could, in fact, be in the dozens of miles) at the same time that it addresses overall capacity to the region. Access Northeast will allow firm capacity to be made available to electric power generators through capacity contracts entered into by EDCs. When power generators have access to capacity that is firm directly to their plant, they will not be subject to the spot market pricing and electric consumers in the region will maximize energy savings.

The Access Northeast project will upgrade existing facilities on the Algonquin and Maritimes systems and develop market area liquefied natural gas ("LNG") storage assets in New England to deliver, on peak days, up to 0.9 Bcf/day of natural gas.[13] This increased supply has been specifically designed to provide a firm fuel supply for approximately 5,000 MW of natural

[13] In order to calibrate the capacity provided by Access Northeast to generators' needs, Access Northeast's developers carefully examined dispatch costs on a peak natural gas demand day (*i.e.*, extreme cold) in ISO New England, comparing the marginal cost of natural gas plants directly connected to the Algonquin and Maritimes systems with the marginal costs of other dispatched resources. The developers observed that regional costs could be reduced significantly if Algonquin provided an additional 0.9 Bcf/d of firm natural gas capacity, serving a critical 5,000 MW of those directly connected generators.

gas fired electric generation. By focusing on the specific needs of the power generators and providing firm services directly to the generators, Algonquin and Maritimes (as expanded by Access Northeast) will provide the incremental pipeline capacity New England so desperately needs to reliably serve its electric power generation fleet.

Because over sixty percent (60%) of natural gas-fired electric generators are already directly connected to the existing Algonquin and Maritimes pipeline systems, an environmentally friendly incremental expansion (within existing pipeline rights-of-way) of those existing systems, coupled with the increase in LNG storage capability, provides unique benefits to New England's generators (and consequently New Hampshire's electric consumers).[14] Other proposals that claim to serve power plants connected to Algonquin and Maritimes simply cannot back their claims with firm service directly to the plants on those pipelines. Instead, these proposals must rely on the availability of interruptible capacity on Algonquin and Maritimes (which currently is not available on the days that it is needed most because it is being used to serve LDC load) to reach these generators. As a result, the proponents of these proposals are asking New Hampshire electric consumers to invest billions of dollars in a proposal that ultimately leaves the region once again subject to the volatility of interruptible services that may not be available when the region needs these services most. Conversely, Access Northeast will allow firm capacity to be made available directly to electric power generators through capacity contracts entered into with EDCs. When power generators have access to this firm capacity

[14] System maps provided as Attachment 2 identify the names and locations of the generators directly connected to the Algonquin and Maritimes systems, and a table provided as Attachment 3 identifies the directly-connected generators that together account for nearly 9,600 MW of generation capacity, as compared to those generators directly connected to other pipelines in New England.

directly to their plants, they will not be subject to the spot market pricing and the region will maximize its energy savings.

The Path Forward: The Commission Should Evaluate Projects Based on a Full, Complete and Accurate Measure of Costs and Benefits.

Spectra Energy urges the Commission to evaluate the full measure of each project's costs and benefits, whether in the context of reviewing a contract for natural gas capacity or (if the Commission finds it advisable) an RFP. Unfortunately, the Staff Final Report does not accurately and completely capture such costs or benefits. The Staff Final Report has focused on two projects that would each increase New England's natural gas supply, one with a focus on providing such natural gas to the electric power sector (Access Northeast) and the other Northeast Energy Direct project ("NED") advanced by the Tennessee Gas Pipeline Co. ("TGP") which appears to be a project evolving from one supported by traditional natural gas shippers (*i.e.*, LDCs) to one that belatedly is offering services to the electric markets. Significantly, the Staff Final Report acknowledges that TGP is only directly connected to twenty-seven percent (27%) of generation capacity[15] but does not include "last mile" charges for the remainder of generation capacity. Notably, the less than one-third of capacity directly connected with TGP is not located where the generation growth is occurring. Three recently announced new power plants (CPV Towantic, Salem and Invenergy) will all be directly connected to the Algonquin systems, which, along with the location of recent or pending nuclear retirements (Pilgrim and Vermont Yankee) emphasizes Algonquins's "last mile" advantage and footprint.

Moving natural gas that "last mile" to generators not directly connected to TGP would remain in serious question. Assuming the natural gas could be delivered that "last mile" given

[15] Staff Final Report, at 23.

the current or expected capacity of the directly-connected pipelines, last-mile transport would require payment of the standard tariff for each pipeline[16] and any additional costs related to additional pipeline expansions. Further, while TGP may be directly connected to twenty-seven percent of generation capacity, it is not clear that TGP would be able to provide ***firm service*** to support that generation. Provision of ***firm service*** to the TGP-connected generators may cause the project to incur additional costs. Access Northeast's ability to deliver on a firm basis natural gas supplies to natural gas-fired power plants is a fundamental and critically important differentiation from other projects and one that the Commission should consider of paramount importance in its analysis of developing cost effective and environmentally sound natural gas infrastructure that will best serve the electric consumers of New Hampshire. Only additional natural gas pipeline capacity, from a project that actually reaches generation facilities, will allow the region to see the benefits of decreased electricity prices and increased electric reliability.

Spectra Energy urges the Commission to consider the full measure of other costs and benefits, and to ensure that any comparison between projects is based on truly comparable information. In comparing the two projects, the Staff Final Report places undue emphasis on certain generators' dual-fuel capability, and discounts the importance of Access Northeast's transportation and storage services that are tailored specifically to serve the needs of electric power generators. Most critically, the Staff Final Report bases its evaluation of the relative benefits of Access Northeast and NED by comparing reports by ICF International that were not prepared on a comparable basis: ICF's report on Access Northeast ("ICF Access Northeast Report") and ICF's report on NED ("ICF NED Report", collectively "ICF Reports"). First and

[16] At present, the standard tariffs are approximately $0.55/dth per day for the Maritimes & Northeast Pipeline ("Maritimes") and/or $0.26/dth per day for Algonquin for the customer's contractual maximum daily transportation quantity.

foremost, the ICF NED Report evaluated the benefits of pipeline capacity which would be built to serve both LDC and EDC customers while the ICF Access Northeast Report considers benefits only to EDC customers. The ICF Reports are not based on the same assumptions and cannot support a direct comparison between projects. The ICF Reports also use different assumptions for future resource retirements and natural gas availability and demand. Finally, the ICF Reports do not account for the "last mile" costs—a much more significant cost for the NED project. As a result, utilizing the ICF NED Report to evaluate electric customer impacts results in an overstatement of NED's benefits relative to its costs, and any comparison of the NED and Access Northeast projects based solely on the ICF Reports is incomplete and inaccurate.

COMMENTS

1. **The Commission should confirm that EDC contracts for natural gas capacity are legally permissible, recoverable in rates, not prohibited under affiliate transaction rules and that an RFP is neither legally required, nor necessary to advance the best interests of the electric consumers.**

   a. ***Spectra Energy concurs with Staff's analysis supporting the premise that EDCs may enter into gas capacity contracts under the Restructuring Statute.***

The Staff Final Report re-affirmed the position articulated in Staff's July 10, 2015 Memorandum (the "Staff Legal Memorandum") regarding the legal authority that may allow EDCs to enter into natural gas capacity contracts, specifically that "the Commission could conceivably hold that RSA 374-F allows" EDCs to enter into natural gas capacity contracts with natural gas pipeline operators (emphasis in original).[17] The Staff Final Report also notes that "[g]iven 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

[17] Staff Final Report, at 10.

rule that gas capacity purchases were contemplated by RSA 374:57, and therefore allowed."[18] Spectra Energy agrees. Spectra Energy urges the Commission to find that EDCs are authorized to enter into natural gas capacity contracts with pipeline operators, whether such authority is grounded in RSA 374-F, RSA 374:57, or both.

b. *Spectra Energy agrees that EDC costs relative to natural gas pipeline capacity are recoverable in rates if prudent, just and reasonable.*

As Staff acknowledged in its Legal Memorandum, "[b]road discretion is assigned to the Commission in the fixing of rates."[19] In its Final Report, Staff noted that EDCs would bear the burden of showing that increased costs would be justified, and that in evaluating such costs:

> 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.[20]

Spectra Energy agrees that costs incurred by EDCs in acquiring natural gas capacity should be recoverable in rates if they are prudent, just and reasonable as such criteria are typically evaluated by the Commission.

EDCs have a responsibility to provide reliable service to customers at rates that are just and reasonable.[21] By making firm natural gas capacity commitments on a project that actually delivers natural gas to the generators, the EDCs can further respect this mandate by ensuring that existing and new natural gas generators have access to natural gas whenever it is needed. This reliability is increasingly important as fewer and fewer alternative sources of generation (*e.g.*,

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[18] *Id.* at 11.

[19] Staff Legal Memorandum, at 6.

[20] Staff Final Report, at 12.

[21] RSA 374:1; RSA 374-F:3, I.

coal, oil, nuclear) are available due to retirements. Thus, just as the costs associated with EDC investments to improve the electric transmission and distribution system that improve reliability are appropriately recovered from electric consumers, the costs associated with investments in natural gas transmission capacity that improve reliability of the electric system are also, subject to Commission review, appropriately recovered from electric consumers. In contrast, projects that do not actually deliver natural gas to the generators but that are designed instead to position natural gas in hopes that it reaches some generators and impacts price, is short-sighted and unnecessarily puts electric consumers at risk for financial benefits that may fall well short of the intended goal.

The New Hampshire Supreme Court in *Legislative Utility Consumers' Council v. Public Service Co.*, 119 N.H. 332 (1979) offered contrasting examples of costs that were deemed recoverable (*i.e.*, prudent, just and reasonable), and costs not deemed recoverable. The Court held that the Public Service Company of New Hampshire ("PSNH") was not entitled to recover costs related to its investment in an appliance business, because the court could "envision no set of circumstances where it could be said that the company's pursuit of an appliance business is devoted to meeting the energy needs of its customers."[22] As the court made clear, "[p]roperty not devoted to the production and delivery of energy to the consumer is not includable in the rate base…"[23] By contrast, an EDC's investment in increased pipeline capacity that actually delivers gas to the generators on a firm basis would clearly be devoted to facilitating the availability of natural gas for electric generators, thereby allowing such generators to meet the energy needs of EDC customers in a cost-effective manner.

[22] *Legislative Utility Consumers' Council v. Public Service Co.*, 119 N.H. 332, 354 (1979).

[23] *Id.*

As Staff acknowledged in the Legal Memorandum[24] and the Final Report,[25] RSA 374-57 provides a potential mechanism for approval of natural gas capacity contracts before the next EDC rate case. Significantly, in a review of power purchase agreements ("PPAs") proposed by PSNH under RSA 374-57, the Commission concluded that:

> market prices are not the sole or dispositive criterion for evaluating the PPAs. The legislative scheme developed over time as evidenced throughout RSA Title XXXIV [i.e., New Hampshire's public utility laws, including RSA Chapter 374] sets forth a variety of purposes and factors, which expresses recurring themes favoring fuel diversity and renewables, economic development, environmental and health impacts, and energy security, and which grants substantial discretion to the Commission relative to rate setting.[26]

Spectra Energy urges the Commission to confirm that natural gas capacity contracts may be submitted for approval under RSA 374-57, and that ***such contracts would be fully evaluated for prudence and reasonableness***.

c. *The Commission has recently approved a natural gas capacity transaction of an affiliated customer to the project developer, applying the reasonableness standard and without an RFP.*

The Commission's October 2, 2015 Order No. 25,822 ("Liberty Order") approving a Precedent Agreement between EnergyNorth Natural Gas (d/b/a Liberty Utilities, or "Liberty") and TGP provides a recent example of Commission approval of a natural gas pipeline capacity agreement using the traditional analysis of whether such costs are prudent, just and reasonable and without requiring an RFP. The Commission's "statutory review of the Precedent Agreement is limited to consideration of Liberty's prudence in entering into the Precedent Agreement, and

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[24] *See,* Staff Legal Memorandum, at 5.

[25] *See,* Staff Final Report, at 11.

[26] Order No. 25,305, at 32-33.

the reasonableness of the terms of the agreement."[27] By contrast, the Staff Final Report (without citing specific statutes, regulation or precedent) concludes that an RFP process would be "critical for protecting consumer interests, and ensuring that cost recovery of such investments are just, reasonable, and in the public interest."[28]

Spectra Energy urges the Commission to engage directly in a thorough review of natural gas capacity agreements and "apply the traditional ratemaking criteria"[29] to allow cost recovery for prudent, just and reasonable costs, consistent with the Liberty Order. The Commission reviewed Liberty's methodology for comparing costs between NED, the Spectra Energy Atlantic Bridge project and the TransCanada/Portland Gas Continent to Coast (C2C) project and concluded that Liberty had "appropriately considered alternatives to the capacity it contracted for in the Precedent Agreement, based on price and non-price factors." Specifically, the Commission noted that "[t]he projected capacity costs associated with the C2C and Atlantic Bridge projects exceed the Precedent Agreement's capacity costs, without needed upgrades to the Concord Lateral, and the capacity contracted for in the Precedent Agreement will provide greater benefits."[30] Critically, such evaluation of relative costs and benefits was conducted by Liberty (and ultimately reviewed and approved by the Commission) ***without*** a formal RFP process. The Commission should confirm that EDCs may contract for natural gas capacity

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[27] The Commission acknowledged that the contemplated deal "avoids immediate and costly upgrades" to the Concord Lateral that would otherwise be required to deliver natural gas to Liberty's service territory. Liberty Order, at 28. The Commission also concluded that Liberty had adequately protected electric consumers from costs associated with excess capacity. Liberty Order, at 29-30. For these and other reasons, the Commission approved the Precedent Agreement (as modified by settlement agreement with the Commission) as just, reasonable, and serving the public interest. Liberty Order, at 25.

[28] Staff Final Report, at 12.

[29] *Id.* at 12.

[30] Liberty Order, at 28.

absent an RFP, and should evaluate the reasonableness of such transactions on the same basis that it used to evaluate the Liberty-NED deal.

In the Final Report, Staff noted that "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…"[31] Spectra Energy agrees, and stressed that affiliate transaction rules do not prohibit the contemplated natural gas capacity contracts. Indeed, The Liberty Order provides a recent example of Commission approval of a Precedent Agreement involving affiliated entities. Liberty sought Commission pre-approval of a Precedent Agreement enabling it to acquire firm capacity on the NED pipeline to serve its LDC customers. Notwithstanding Liberty's relationship with NED proponents[32] and selection of the NED project outside of a formal RFP process the Commission found that the Precedent Agreement is just and reasonable and serves the public interest.[33] Access Northeast shippers have corporate relationships with Access Northeast project developers analogous to Liberty's relationship with NED. Access Northeast EDCs have negotiated agreements with Access Northeast in an arms-length process consistent with Affiliate Standard of Conduct requirements (both state and federal). As such, Spectra Energy urges that the Commission analyze the natural gas capacity agreements contemplated relative to the Access Northeast project on the same basis as the Liberty-NED agreement.

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[31] Staff Final Report, at 11.

[32] The Commission discussed the relationship between relevant entities as follows: "Algonquin Power & Utilities Corp. ("APUC") owns both Liberty Pipeline and [Liberty]. Liberty Pipeline and Kinder Morgan, Inc. (Kinder Morgan), jointly own Northeast Expansion, LLC which in turn owns the proposed NED Pipeline….The value of Liberty Pipeline's interest in Northeast Expansion is up to $400 million." Liberty Order, at 8-9.

[33] *Id.* at 25.

d. ***The best interests of electric consumers would be most effectively served by expeditiously confirming that EDC contracts for natural gas capacity may be presented to the Commission for action and approval.***

At the beginning of this investigation, Staff invited stakeholders to provide views on the root cause of high and volatile winter wholesale and/or retail electricity prices. As the Staff Final Report recognized, "[a]lmost all of the stakeholders that addressed this issue directly expressed the opinion that [the] cause of the problem can be attributed to a wholesale market imbalance of supply and demand for natural gas."[34] Naturally, the most efficient way to address this imbalance is to promptly increase the supply of natural gas to the relevant power generation facilities so that it meets the increasing demand. Given the capacity constraints on existing natural gas pipeline infrastructure, natural gas will not be available to electric power generators unless incremental capacity improvements are made on the pipelines to which the generators are directly connected.

Urgent action is needed to address the high and volatile electric prices caused by New England's constrained natural gas supply. Every winter before adequate energy resources are secured, New Hampshire electric consumers will continue to pay electricity rates that are higher than they otherwise need to be. Furthermore, in every winter that New England's natural gas generators operate without adequate firm natural gas capacity, the region is at risks that some combination of extreme weather, power generation resource retirement (*e.g.*, retirement of existing coal-fired generation or the recently announced retirement of the Pilgrim nuclear power plant, as discussed above) and other factors will seriously threaten grid reliability.

The timing and cost of the solution to be implemented is directly related to the timing of project identification. New Hampshire EDCs will be prepared to offer natural gas capacity

[34] Staff Final Report, at 14.

agreements with Access Northeast for Commission approval by the end of this calendar year. By contrast, an RFP process, especially if coordinated with other states, will almost certainly introduce significant (and procedurally unpredictable) delays. For example, the Draft Clean Energy RFP being pursued by the three southern New England states (as it currently exists in draft) provides that proposal submissions will be due 75 days after the issuance of the RFP, that bidders will be selected between 165 and 255 days after the issuance of the RFP, and that contracts will be submitted for approval between 255 and 345 days after RFP issuance.[35] As these timelines do not include the time required to develop the bid solicitation documents, and other delays may be inevitable, adopting a similar process in New Hampshire would cause project selection, and ultimately project completion, to be delayed by more than a year.

2. **In assessing the relative merits of different natural gas infrastructure solutions, the Commission should evaluate the full scope of costs and benefits provided by each proposal, using criteria as clarified below.**

   a. ***Natural gas available on the New England pipeline network will not provide price or reliability benefits unless it can flow the "last mile" to each electric power generation resource.***

Projects that propose to provide firm transportation to hubs (and not the electric power generators themselves) do not fully or adequately address the basic problem—the inability of electric power generators to directly access a supply of natural gas during peak demand periods. Thus, an evaluation designed to consider reliability and reduced energy costs that simply considers aggregate natural gas capacity available is deficient, as it does not adequately capture whether the natural gas can or will make it the "last mile" to the electric power generators themselves. Unless natural gas can be delivered the "last mile" to generators with associated storage capabilities to ensure supply, such natural gas will not be available where and when it is

[35] Draft Clean Energy RFP, at 28.

needed most. In evaluating proposed natural gas solutions, Spectra Energy urges the Commission to focus on the most critical issue and evaluate whether any proposed natural gas solution will actually enable electric power generators to have natural gas available to be dispatched when needed to ultimately achieve the electricity pricing results desired.

This concept of subscribing to the complete transportation path is what Spectra Energy has referred to in discussions with staff as "focusing on reliability". In layman's terms, to the extent the overall electric grid reliability is premised on natural gas fired electric generation being available on a peak winter day, that total amount of natural gas fired electric generating capacity and the complete path of that capacity must be supported by firm transportation. Furthermore, such reliability is essential and directly related to favorable pricing. The term 'reliability" has become Spectra Energy's shorthand for the inherent linkage between price and ensuring that the natural gas actually reaches the generator. Spectra Energy vigorously maintains that inability of natural gas generators to be dispatched when called upon will cause other, higher-priced units to set the marginal price, thereby resulting in higher and more volatile prices.

The Staff Final Report does not adequately consider the critical "last mile" costs. As the Staff Final Report notes, "TGP is directly connected to only 27% of [New England's] total installed gas capacity, or about 4,900 MW…"[36] The Staff Final Report goes on to state that "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."[37] As the ICF Report clearly acknowledges, however, 3,328 MW (out of the 9,049 MW of the capacity that NED purports to

[36] Staff Final Report, at 23.

[37] *Id.*

serve) is served through "Indirect Deliveries" supplying Algonquin.[38] ICF acknowledges in a footnote, however, that "[p]ower generators who receive gas deliveries through constrained laterals may require additional pipeline investments to utilize capacity made available by the construction of NED."[39] Absent upgrades to the Algonquin system (or new directly-connected) pipelines) the natural gas required to serve 3,328 MW of generation capacity indirectly served by NED (and directly connected to Algonquin) ***simply will not reach the generators***. Further, the Staff Final Report does not fully account for the costs that would be incurred in delivering natural gas the "last mile" to those generators not directly connected to NED. Any natural gas "indirectly" supplied by NED and flowing over other pipelines would require hundreds of millions of dollars in new expansions and incur the standard tariff for each pipeline (at present, approximately $0.55/dth per day for Maritimes and/or $0.26/dth per day for Algonquin of customer's contractual maximum daily transportation quantity).

In an analogous situation involving the delivery of natural gas to an LDC, the Commission's Liberty Order recognizes the importance of these "last mile" costs and that such costs must be considered by utilities. Specifically, the Commission noted that Liberty's "access to the capacity of either [the Atlantic Bridge and/or the C2C project], however, would require upgrades to the TGP Concord Lateral. The costs of the Concord Lateral upgrades . . . would be an addition to the costs associated with the C2C and Atlantic Bridge projects."[40] The Commission should likewise be cognizant of the "last mile" costs related to the NED project. As Liberty needed to be sure that natural gas made it the "last mile" to its LDC customers in New

[38] ICF NED Report, at 10.

[39] *Id.* at 10 n. 5.

[40] Liberty Order, at 7.

Hampshire, EDCs need to ensure that natural gas makes it the "last mile" to critical generation resources along the Algonquin and Maritimes systems.

b. *Dual fuel generation capability does not address the fundamental problem of insufficient natural gas infrastructure to serve the needs of the electric industry.*

The Staff Final Report highlights the dual-fuel capability of 6,000 MW of natural gas-fired electric generation capacity to argue against reliability as a significant concern.[41] Spectra Energy submits, however, that dual-fuel capability does not address the fundamental problems posed by lack of natural gas capacity. Significant supply constraints exist all winter. Such supply constraints may force dual-fuel generators to rely on oil for extended periods. As Staff recognizes, the "resulting increase in dependence on back-up fuel for generation can also present reliability risks and pricing consequences, as demonstrated by the difficulties of replenishing oil supplies in winter 2013/14…"[42] To this end, we note that oil is typically more expensive than natural gas, and (as discussed in Section 3(a)) causes far greater environmental harm when used to generate electricity. Only a solution that (like Access Northeast) provides firm, year-round natural gas capacity can deliver the year-round environmental benefits realized by a switch from oil to natural gas. While it is possible (though not certain) that dual-fuel capability may avert or minimize blackouts and brownouts should a grid reliability problem occur, it is not an adequate or economically and environmentally appropriate substitute for firm availability of natural gas.

c. Contract terms that align with generator business needs will most effectively reduce the price spikes associated with constrained natural gas capacity.

An evaluation of natural gas-based solutions should consider not only the amount of natural gas available directly to the power generators but the terms on which it is offered.

[41] Staff Final Report, at 17-18.

[42] *Id.* at 18.

Access Northeast's contract terms (*e.g.*, reserved no-notice service, non-ratable delivery) will allow generators to best utilize the natural gas capacity to run at economically efficient prices and support renewable generation resources. Only Access Northeast's unique combination of natural gas pipeline capacity and LNG storage will allow it to provide the services tailored to the needs of electric power generators and at quick start requirements to meet backup generation needs.

Traditionally, natural gas capacity is transacted in 24-hour blocks a day in advance. By contrast, natural gas generators may only have short notice under ISO-NE's dispatch system. One of the key benefits provided by natural gas power generation, and critical for backup of renewable generation, is this quick-start potential, especially when contrasted to the long ramp-up times required of coal and other legacy fuels. That said, natural gas generators can only exercise quick-start potential when sufficient fuel is available on short notice. The non-ratable service that would be available through Access Northeast would allow generators to schedule natural gas in short hourly blocks that would reflect varying electric generation needs through the day. As natural gas-fired generators tend to be dispatched during peak electric demand periods, they may require natural gas supply for a few hours at a time rather than the whole 24-hour cycle.

Electric generators have signaled the need for service tailored to the needs of the electric generation industry, particularly in comments filed with the Federal Energy Regulatory Commission (FERC). In those comments, the Alliance for Cooperative Energy Services Power Marketing LLC (a collaboration of 21 power supply electric cooperatives) stressed that "[f]lexible pipeline services and commodity procurement products must emerge to address the growth of gas-fired electric power generation." It identified non-ratable service, no-notice service and after hours scheduling as key features of procurement policies that would serve the growing need for natural gas-fired electric power generation.[43] Similarly, electric generator EquiPower Resources Corp. urged the gas and electric industries to ***"develop and implement a construct that allows natural gas to be delivered to electric generators on a no-notice, non-ratable basis throughout each day to ensure that the electric load is reliably served."[44] Access Northeast will provide such service.***

The first aspect of Access Northeast's unique service is the reservation of pipeline transportation capacity. Under the current nomination and scheduling rules for natural gas transportation, parties must follow specific timelines established by LDCs and the natural gas industry. At the timely cycle, which is 11:30 am Central on the day before gas flows at 9:00 am Central the next day, parties nominate their specific transportation activities. Pipelines evaluate those activities 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 activity may not be scheduled at the timely cycle, or any additional nomination cycle that has been established.

Under the tariff contemplated by the Access Northeast project (discussed in prior submittals as Energy Reliability Service or "ERS"), the primary firm transportation path is held open at the timely scheduling cycle. Consequently, ERS can be nominated at or during any of forty-one additional nomination cycles to be provided by Algonquin and/or Maritimes as expanded through Access Northeast. In essence, the transportation path is available to be

[43] Alliance for Cooperative Energy Services Power Marketing LLC, comments in FERC Docket No. RM14-2-000 (Nov. 28, 2014) at 12.

[44] EquiPower Resources Corp., Motion to Intervene and Comments in FERC Docket No. RM14-2-000 (Nov. 26, 2014) at 8 (emphasis added).

nominated 24/7, and as long as supply is confirmed, those activities are able to ramp up or down based on the expected use profiles.

Along with the no notice capability, the integration of LNG storage for Access Northeast provides flexibility by allowing shippers that have ERS to commence delivery for up to two hours before confirmed supply begins to flow, thus allowing for a "quick start" of the plant. With the transportation space already reserved on the pipeline, this quick start aspect enhances the generator capability to start flowing gas without the commensurate supply being delivered. The generator simply has to notify the pipeline that they will be using the ERS service, and will begin to pull gas off the pipeline. A generator can nominate its upstream supply from any of the primary firm receipt points under its ERS service agreement. If the supply is not nominated, the storage provided by the LNG allows the pipeline to start pulling in supply, if necessary, until the generator's supply starts to flow within that two hour period. This service is invaluable to electric generators. Not only will the generators know that they have pipeline space available to them at any point in time during the day or night, but they will also be able to quickly ramp up on a moment's notice if dispatched by ISO-NE. With this feature, Access Northeast will also provide the EDCs with the opportunity to acquire natural gas at deeply discounted summer prices (compared to winter prices), to convert and store this natural gas as LNG and to make such natural gas available during the winter period.

TGP, just last month, outlined a service similar to what Access Northeast is offering under ERS for TGP's NED project, but TGP has provided no specifics on what additional facilities would be required to support such service. TGP's proposed service is only effective for those limited number of directly connected generators on the TGP system as NED (greenfield pipeline) does not connect directly to any gas-fired generation in New England. As acknowledged in the Staff report, TGP interconnects with approximately 27% of New England generation (approximately 4900 MW). This TGP proposal fails to directly reach the greater percentage of New England power generation located on Algonquin and Maritimes. These will remain a pipeline system away from NED. It would be ill-advised for the New England EDCs to invest in a solution focused on deliverability of fuel to the 4,900 MW of generation interconnected to TGP but which cannot reliably reach the 9,600 MW of generation interconnected to Algonquin and Maritimes.

NED cannot provide the non-ratable flow service flexibility that Access Northeast provides. This flexibility is only as good as the delivery capability of the "last mile" pipeline. In order to provide the type of reliability that ERS proposes, NED would have to deliver into Wright or Dracut on a non-ratable basis, and in turn, that receiving pipeline would have to then deliver gas into Algonquin on a similar non-ratable basis prior to Algonquin then delivering non-ratably to the ultimate generator being dispatched. Historically, upstream pipelines are either unable or unwilling to provide the downstream pipeline with anything greater than 1/24th of the total nominations scheduled at the delivery point(s). To be clear, all current and historical supply receipts into Algonquin from Tennessee occur on a ratable basis, so ***all*** of the non-ratable flow flexibility that generators on Algonquin have always benefitted from is being provided exclusively by Algonquin. Without the new Access Northeast facilities, the Algonquin system would not have the specific design characteristics to deliver NED receipts on a non-ratable basis and therefore, may or may not be able to provide sufficient flow swings and delivery pressures desired by its directly connected generators. It is highly unlikely that the services that NED proposes would trickle downstream to the greater share of generation on the Algonquin system. These factors confirm the advantages of Access Northeast and the ERS service.

d. In judging the costs associated with each natural gas pipeline solution, the Commission should consider the associated drivers of natural gas commodity prices, and liquidity of receipt points that help keep prices down.

In addition to providing delivery over the "last mile" to electric generators, Access Northeast's diversity of upstream pipeline connections allows natural gas to be sourced from a wide range of supply points. By having firm capacity entitlements, natural gas-fired generators will no longer be solely dependent on buying gas at Algonquin City Gate but can go upstream and purchase gas at multiple pipeline interconnects that are at significantly lower prices, on a firm basis. Upstream supply pipelines that will supply the Access Northeast project include: Tennessee Gas Pipeline, Millennium Pipeline Company, LLC and the Iroquois Gas Transmission System. Connection to these source pipelines will be accomplished through direct connections at three distinct junctions: Mahwah, New Jersey; Ramapo, New York and Brookfield, Connecticut. In addition to firm access to supply through these points, Access Northeast may also offer flexibility of receipt at other pipelines including Texas Eastern Transmission, LP, Columbia Gas Transmission Corporation, Transcontinental Gas Pipeline Corporation and Portland Natural Gas Transmission System.

These supply points have been sufficient to support the current and proposed expansion on Algonquin and will continue to support additional expansion by Access Northeast, as they have recently expanded delivery capability into the region and/or are currently developing expansion projects to increase capacity in the near future. These expansions have already resulted in a current level of supply that exceeds current pipeline takeaway capacity at Mahwah and Ramapo alone. Thus, supply dynamics on Algonquin are supportive of additional pipeline expansions from these points to the electric power generators. The Access Northeast project maximizes flexibility to identify low-cost suppliers in a wide geographic area, obviating the need to acquire firm capacity on any particular upstream pipeline.

By contrast, the NED project's sole receipt point is Wright, New York. Supply to Wright is already constrained, and while capacity increases into Wright may alleviate existing constraints, it may not provide enough additional natural gas to fully supply the NED project. The Commission noted "the Wright market's uncertainty" in evaluating Liberty's participation in the NED project, and expressed reassurance thanks to the "Precedent Agreement's requirement that a certain level of liquidity must exist at Wright before Liberty's customers are required to purchase the capacity contracted for in the Precedent Agreement."[45] Spectra Energy urges the Commission, in this far greater context, to likewise seriously consider the impact of receipt points in evaluating the prudence and reasonableness of EDC contracts for natural gas capacity.

e. Any comparison of Access Northeast and NED must be based on the same methodology and assumptions.

Spectra Energy acknowledges and supports Staff's conclusion that increased natural gas pipeline capacity will (to the extent natural gas actually reaches the generators) lower electric prices and otherwise advance consumer interests. That said, the Staff Final Report's discussion of the relative merits of Access Northeast and NED reflects incomplete and/or inaccurate information that must be clarified and corrected. Specifically, Spectra Energy offers the following clarifications on the use of the ICF Access Northeast Report and ICF NED Report to compare such projects.

The Commission should be aware of a few key differences between the two reports which could overstate the benefits presented by NED and understate the costs presented by NED.

[45] Liberty Order, at 28.

These differences preclude the use of the ICF Reports for a direct comparison of the costs and benefits of the Access Northeast and NED projects. To the extent the Commission allows EDCs to directly present natural gas capacity contracts for review and approval, the Commission should verify that the EDC is comparing costs and benefits of alternatives based on truly comparable analyses. To the extent that the Commission mandates an RFP process, such analysis should start fresh from the bid documents submitted, and not rely on either the ICF Reports that were done at different times and with different assumptions or the Staff interpretation of such ICF Reports.

i. *NED's volume and benefits were calculated based on EDC and LDC contributions, while only EDC-related costs were considered, thereby skewing the cost-benefit ratios relative to the NED project.*

As the Staff Final Report acknowledged, "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."[46] The ICF NED Report reflects the benefits of NED based on the full 1.3 Bcf/d of LDC and EDC capacity. The Staff Final Report bases its calculations on a "$400 million levelized annual cost for the electric portion of the NED project" rather than the full cost of the project.[47] The Staff Final Report's analysis of NED's costs and benefits therefore appears to understate NED's cost and/or overstate NED's benefits. On the other hand, the ICF Access Northeast Report reflects the specific benefits and costs of Access Northeast to the EDC customers only, and is reflected as such in the Staff Final Report.

[46] Staff Final Report, at 45.

[47] *Id.* at 29.

It may not have been clearly understood that the Access Northeast ICF report looks specifically at the benefits related to EDC investment in incremental pipeline capacity expansion via Access Northeast. In the Access Northeast report, ICF only evaluated the benefits related to the 0.9 Bcf/day gas delivery capability of Access Northeast. In so doing, Access Northeast instructed ICF to assume that LDC demand growth was met via a generic expansion of pipeline capacity to New England totaling approximately 0.5 Bcf/day. The benefit of this generic pipeline serving LDC customers was not included in the Access Northeast study, whereas the NED study includes the benefit of increased supply to LDCs as part of the overall NED project. The staff interpreted that the benefits that accrue to electric customers from NED would include the impact of the gas LDC contracts for approximately 0.55 Bcf/day. Thus the comparison of the two projects is not comparing equivalent options.

In order to estimate a more consistent comparison, Access Northeast has reviewed some additional price data that ICF had provided in preparing the ICF Access Northeast Report. The additional price data assessed a combined benefit from the reduction of average gas and power prices (excluding volatility) that results to consumers from both the 0.5 Bcf/day LDC generic project and the Access Northeast project. The additional price data shows that the 0.5 Bcf/day LDC project accounts for approximately 2/3 of the combined benefits over the 10-year study period (2018-2029). Thus, the remaining 1/3 of the combined benefits from average price reduction is attributable to the capacity provided by Access Northeast to EDCs. Applying these LDC versus EDC ratios for the combined benefits of the two projects allows an estimate of EDC-only benefits of the NED project.

In simplest terms, the proportion of benefits provided by LDC-focused and EDC-focused pipeline expansions demands that the benefits attributed to NED be reduced to 1/3 of the benefits identified in the Staff Final Report. The ICF NED Report estimated benefits of $2.1 billion without the volatility reduction component, but again, includes the benefits of the LDC volumes on price reduction. To truly compare the electric savings benefits of the two projects "apples to apples," one must only consider the 10-year average EDC price savings of NED, or approximately $700 million (with no volatility reduction) to $1.4 billion (with high volatility reduction), following the 1/3 benefits explanation above. ICF identified Access Northeast's 10-year average electric savings as between $780 million to $1.2 billion annually.

ii. The ICF Reports were done at different times, using different assumptions regarding natural gas and electricity costs absent increased pipeline capacity. These differences result in higher calculated benefits for NED than for Access Northeast.

As the Staff Final Report acknowledges, the ICF NED Report and the ICF Access Northeast Report used different assumptions in developing baseline conditions against which each project was compared. Specifically,

> 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.[48]

In the two reports, ICF also used different assumptions concerning the retirement of existing units. The ICF Access Northeast Report stated that "approximately 2,800 MW of coal, oil and nuclear generation capacity in ISO-NE is retired by 2018" and includes the Vermont Yankee and Salem Harbor units retired in 2014.[49] By contrast, the ICF NED Report stated "that approximately 3,480 MW of coal, oil/gas and nuclear generation capacity in ISO–NE is retired

[48] Staff Final Report, at 28 n. 56.

[49] ICF Access Northeast Report, at 20.

by 2018 as shown in Table 2; this includes almost 1,000 MW of capacity already retired by the end of 2014."[50] This discrepancy would likely impact baseline price calculations.

In order to allow for legitimate comparisons between projects, the fundamental assumptions about demand and gas availability must be the same.

iii. NED's ability to serve generators on Algonquin is limited (both on a volume basis and quality of service basis) and there could be hard and significant "last mile" costs (and uncertainties) necessary to assure firm deliveries to generators on the Algonquin system.

The ICF NED Report, and the Staff Final Report, did not address NED's ability to directly serve critical New England generation resources. As the Staff Final Report notes, "TGP is directly connected to only 27% of [New England's] total installed gas capacity, or about 4,900 MW…"[51] The Staff Final Report goes on to state that "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."[52] As the ICF Report clearly acknowledges, however, 3,328 MW (out of the 9,049 MW of the capacity that NED purports to serve) is served through "Indirect Deliveries" supplying Algonquin.[53] ICF acknowledges in a footnote, however, that "[p]ower generators who receive gas deliveries through constrained laterals may require additional pipeline investments to utilize capacity made available by the construction of NED."[54]

Absent upgrades to the Algonquin system (and likely upgrades required on the Tennessee Gas Pipeline), the natural gas required to serve 3,328 MW of generation capacity indirectly served by NED ***simply will not reach the generators***. Further, the ICF NED Report did not

[50] ICF NED Report, at 22.

[51] Staff Final Report, at 23.

[52] *Id.* at 23.

[53] ICF NED Report, at 10.

[54] *Id.* at 10 n. 5.

account for the costs that would be incurred in delivering natural gas the "last mile" to those generators not directly connected to NED. Any natural gas "indirectly" supplied by NED and flowing over other pipelines would incur the standard tariff for each pipeline.[55]

3. An evaluation of solutions that focuses only on lowest cost misses half of the picture. The Commission should base its decision-making on an analysis of greatest benefits to electric consumers.

a. Any evaluation of relative merits of different natural gas infrastructure solutions should include a consideration of environmental harm/costs and benefits associated with the proposal.

The transition from coal and oil to natural gas for electric power generation has provided enormous environmental benefits. In 2004, natural gas represented 37% of energy generation, with coal and oil providing a collective 14%.[56] By 2013, natural gas provided 45% of power generation, with coal and oil providing only 7%.[57] Due to this "shift in the fuel mix" (i.e., transition from coal and oil-fired units to natural gas), between 2004 and 2013 emissions related to electric power generation in New England decreased by sixty percent (60%) for nitrogen oxides (NO_x), by eighty-eight percent (88%) for sulfur dioxide (SO_2), and by twenty-eight percent (28%) for carbon dioxide (CO_2).[58] These trends are poised to continue as coal, oil and nuclear generation units are retired (see discussion of Pilgrim retirement in Section 2(e)(ii)) and more natural gas generation units are built.

[55] Such costs would include approximately $0.55/dth per day for Maritimes and/or $0.26/dth per day for Algonquin of customer's contractual maximum daily transportation quantity on an ***interruptible basis***. These costs do not account for the required expansion of Algonquin to reach a significant portion (60%) of the generation with firm gas on the coldest days of the winter.

[56] ISO New England ("ISO-NE"), 2013 ISO New England Electric Generator Air Emissions Report (Dec. 2014) ("2013 Emissions Report") (available at: http://www.iso-ne.com/static-assets/documents/2014/12/2013_emissions_report_final.pdf), at 2.

[57] *Id.*

[58] 2013 Emissions Report, at 1.

This beneficial trend toward natural gas and away from legacy fuels like coal and oil can only continue, however, if there is actually enough natural gas to power the generation fleet. While December, January and February are high-demand months for electricity, they are also high-demand months for natural gas for heating, and consequently the power generation fuel mix shifts away from natural gas and toward coal and oil in the winter.[59] As a result, emissions are increased. As ISO-NE noted in its study of system air emissions, air emissions are highest in January, February, July and December, due to "lower natural gas generation and higher coal- and oil-fired generation."[60] For example, the system's monthly average emissions (in pounds per MW hour) of nitrogen oxides, sulfur dioxide and carbon dioxide are all dramatically higher in February (low use of natural gas) than in October (high use of natural gas).[61]

Table 1: ISO-NE Monthly average emissions (in pounds per MW hour)

Month	NO_X	SO_2	CO_2
February	0.51	0.92	804
October	0.26	0.05	637

Only the firm year-round natural gas capacity offered by Access Northeast would allow natural gas to be fully utilized year-round and thus reduce the seasonal increases in air emissions.

Similarly, increased natural gas pipeline capacity indirectly promotes "wind, solar and other renewable and low carbon energy technologies" and furthers fuel diversity. The intermittent nature of renewable technologies such as wind and solar may pose operational

[59] 2013 Emissions Report*,* at 13; *see also* Remarks by Gordon van Welie, President & CEO, ISO New England, Northeast Forum on Regional Energy Solutions (Apr. 23, 2015) (available at: http://www.iso-ne.com/static-assets/documents/2015/04/northeast_forum_on_regional_energy_solutions_van_welie_remarks_and_slides_04232015.pdf), at 2 ("When natural gas supply to generators is constrained, the ISO must commit other generating resources to maintain system reliability, and these resources are often coal- and oil-fired power plants.").

[60] 2013 Emissions Report, at 20-21.

[61] *Id.* at 39.

challenges as they become more widespread, and this may demand new sources of system flexibility including, potentially, larger operating reserves. If natural gas generators are guaranteed to have the gas they need when called upon to run, such units can provide a reliable backstop for intermittent renewable generation. Natural gas-fired generators, particularly when supported by non-ratable, no-notice natural gas supplies, can be dispatched quickly to fill in any gaps caused by the intermittent nature of renewable generation. An evaluation of natural gas pipeline projects should include such indirect benefits.

Finally, an evaluation of natural gas pipeline solutions should include a consideration of environmental and landowner disruption caused by construction of the pipeline itself, for example by greenfield construction as opposed to improvements on an established pipeline corridor. Unlike other options, more than ninety-five percent (95%) of the pipeline component of the Access Northeast solution will utilize existing pipeline and utility corridors and natural gas infrastructure, thus minimizing environmental and community effects. Further, the use of ninety-five percent (95%) of existing corridors helps minimize construction risk and delays in the region receiving the substantial benefits of a solution focused specifically on power generation and reaching the "last mile" to the generation facilities.

If the Commission approves natural gas pipeline projects, electric generators will have more natural gas available, which will allow these beneficial environmental trends to continue. Thus, in evaluating reductions in greenhouse gas emissions, the Commission should consider the seasonal shift that will persist, and perhaps become more pronounced, if natural gas capacity to the region (and more specifically, to the electric power generators that serve New Hampshire electric consumers) is ***not*** enhanced and account for the ability of natural gas-based solutions to address this historic shift. Access Northeast will provide firm natural gas capacity to sixty percent (60%) of New England's natural gas-fired generation, thereby providing fuel on the coldest days and helping to ensure that oil is not used in place of natural gas.

b. *Any evaluation of relative merits of different natural gas infrastructure solutions should include a consideration of indirect market impacts.*

Additional natural gas capacity provides indirect installed capacity and local sourcing requirement and Forward Capacity Market ("FCM") benefits that should be considered by the Commission in developing any RFP or evaluating EDC contracts for natural gas capacity. Transmission constraints require that New England achieve target levels of locally and regionally installed capacity in order to ensure local electric reliability and resource sufficiency. The simple installation of more local capacity will not guarantee service, however, if such generating capacity does not have sufficient fuel available to run when needed. Thus, projects that will enable local generation to run consistently by making more natural gas directly available provide a benefit by facilitating installed capacity and local sourcing requirements that ensure FCM benefits which should be considered in the evaluation process.

The Commission should also consider a proposal's ability to reduce price volatility in the market as a whole. As Staff recognized, almost all of the stakeholders in this investigation "expressed the opinion that cause of the problem can be attributed to a wholesale market imbalance of supply and demand for natural gas."[62] If all users of natural gas in New England secured pipeline capacity to meet their peak day needs, the delivered cost of gas in New England compared to New York and the rest of the northeast would reflect only a modest premium based on the variable charges to transport that gas to the delivery meters. Achieving this level of pricing parity for New England would maximize the cost savings to energy consumers in the

[62] Staff Final Report, at 14.

form of lower natural gas prices and lower electric prices. Adequate pipeline capacity would also help to alleviate the price spikes that added significant costs to electric consumer bills in recent winters. Again, this reduction in volatility can reduce price risks in the market as whole and should be considered when evaluating the benefits any project can provide.

CONCLUSION

Spectra Energy urges the Commission to 1) confirm Staff's position on EDC cost recovery; 2) establish a timely process to approve timely EDC contracts with pipelines (whether by application or RFP); 3) focus on evaluating the merits of various projects on the ability of such projects to deliver, on a firm basis, natural gas to natural gas generators who play a critical role in reliability and price formation. Spectra Energy appreciates the opportunity to submit these comments and looks forward to its continued participation in the Commission's process to ensure improved natural gas availability in New Hampshire.

Respectfully submitted,
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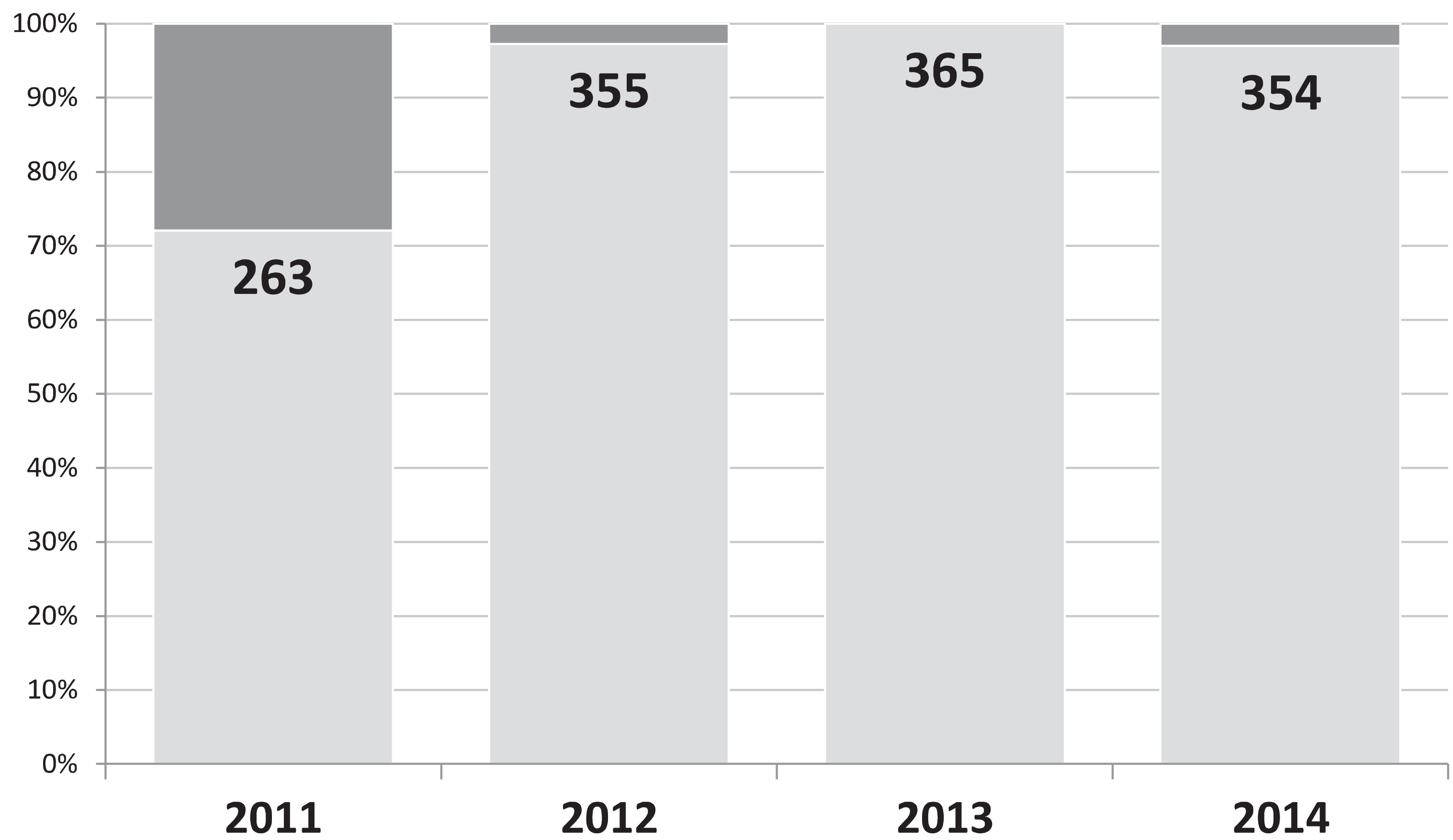
List of Attachments

1. Graph: Days with Zero Interruptible Capacity on Algonquin
2. Maps: Names and locations of Natural Gas-Fired Generators; Aggregation Areas.
3. Table: Natural Gas-Fired Generators Directly Connected to the Algonquin and Maritimes & Northeast Pipelines.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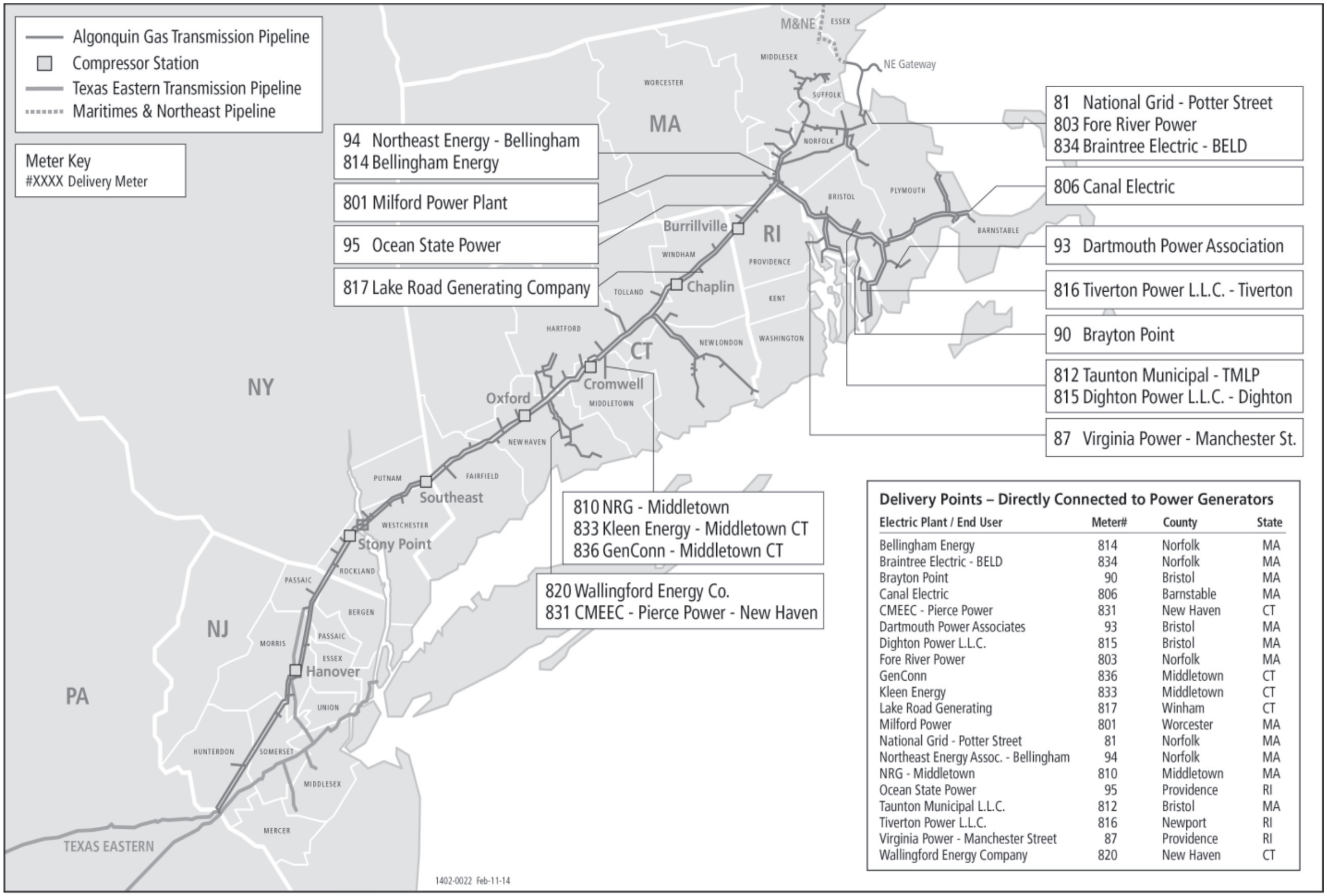
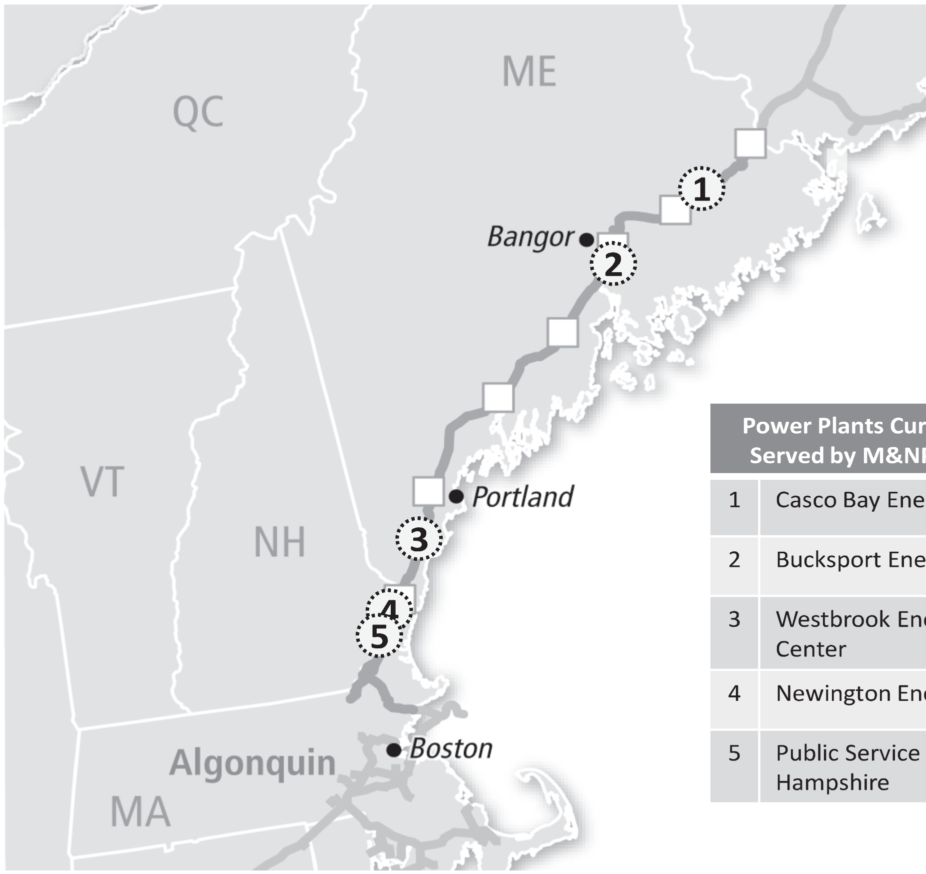


Delivery Points – Directly Connected to Power Generators

Electric Plant / End User	Meter#	County	State
Bellingham Energy	814	Norfolk	MA
Braintree Electric - BELD	834	Norfolk	MA
Brayton Point	90	Bristol	MA
Canal Electric	806	Barnstable	MA
CMEEC - Pierce Power	831	New Haven	CT
Dartmouth Power Associates	93	Bristol	MA
Dighton Power L.L.C.	815	Bristol	MA
Fore River Power	803	Norfolk	MA
GenConn	836	Middletown	CT
Kleen Energy	833	Middletown	CT
Lake Road Generating	817	Winham	CT
Milford Power	801	Worcester	MA
National Grid - Potter Street	81	Norfolk	MA
Northeast Energy Assoc. - Bellingham	94	Norfolk	MA
NRG - Middletown	810	Middletown	MA
Ocean State Power	95	Providence	RI
Taunton Municipal L.L.C.	812	Bristol	MA
Tiverton Power L.L.C.	816	Newport	RI
Virginia Power - Manchester Street	87	Providence	RI
Wallingford Energy Company	820	New Haven	CT

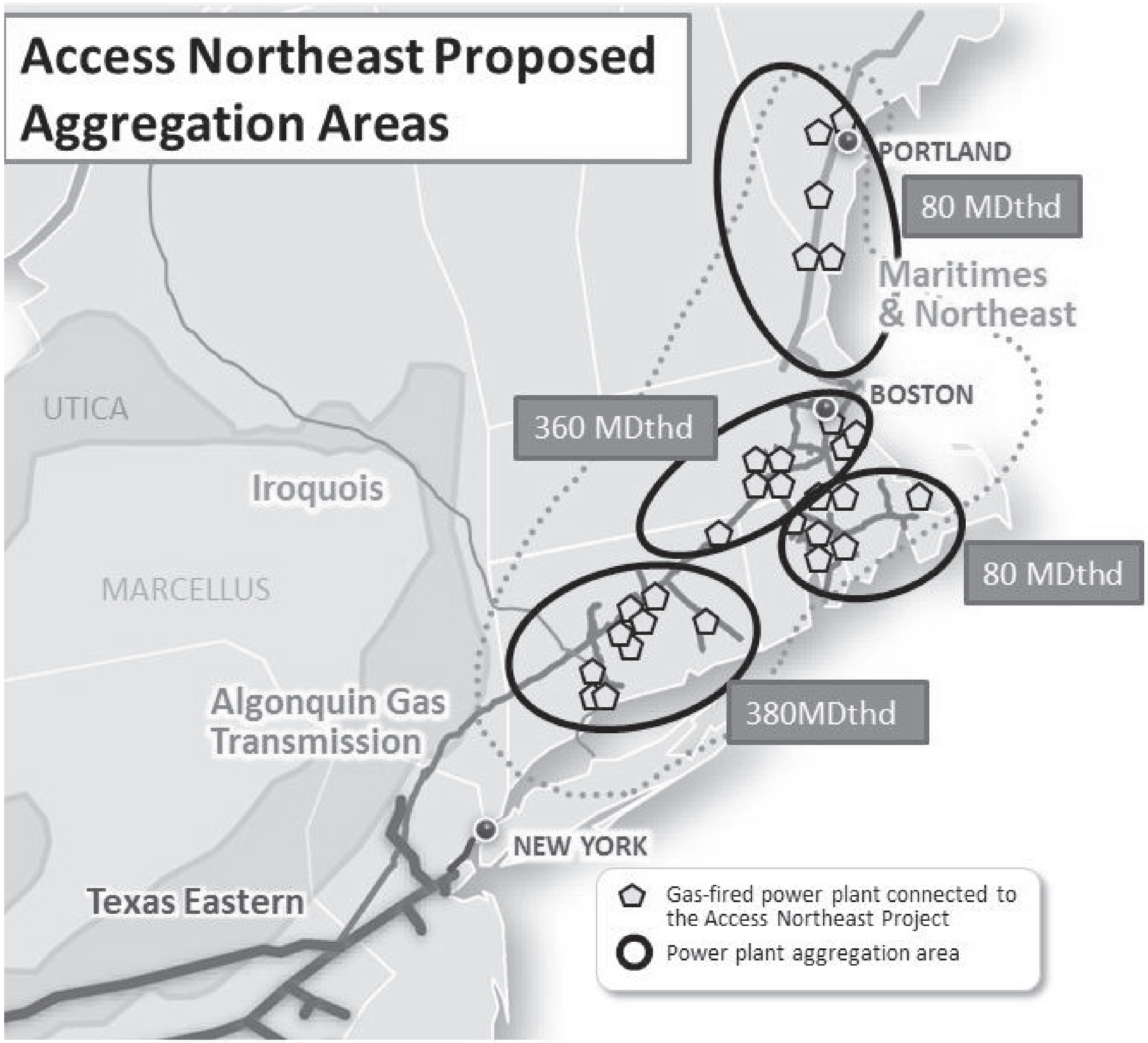
Algonquin Gas Transmission Company: Suite 300 – 890 Winter Street, Waltham, MA, 02451. Algonquin does not guarantee the accuracy of this map nor the title delineation thereon, nor does Algonquin assume any responsibility or liability for any reliance thereon.

Map 1: Names and Locations of Natural Gas-Fired Generators on Algonquin



Power Plants Currently Served by M&NP U.S.		Generating Capacity (MW)	State
1	Casco Bay Energy	540	ME
2	Bucksport Energy	174	ME
3	Westbrook Energy Center	543	ME
4	Newington Energy	525	NH
5	Public Service of New Hampshire	400	NH

Map 2: Names and Locations of Natural Gas-Fired Generators on Maritimes



Map 3: Access Northeast Proposed Aggregation Areas.

Power Plant MW Comparison

AGT/MNUS

Meter #	Meter Name	MW
81	National Grid-POTTER St. (NORFOLK,MA)	92
87	PG&E Manchester St, (PROVIDENCE,RI)	518
90	Brayton Point Energy, LLC	455
93	Dartmouth Power (NORFOLK,MA)	69
94	Bellingham(NORFOLK,MA)	330
95	Ocean St (PROVIDENCE,RI)	652
801	Enron Power (NORFOLK,MA)	175
803	FORE RIVER (NORFOLK,MA)	842
806	Mirant Canal, (BARNSTABLE,MA)	567
810	NRG Middletown, (MIDDLESEX,CT)	369
812	TMPL (BRISTOL,MA)	112
814	ANP BELLINGHAM ENERGY COMPANY (NORFOLK,MA)	523
815	Dighton Power LLC Bristol MA (BRISTOL,MA)	188
816	Calpine Tiverton, (PROVIDENCE,RI)	279
817	PG&E Lake Road (WINDHAM,CT)	863
820	Wallingford Energy Interconnect (FAIRFIELD,CT)	250
831	CMEEC-PIERCE POWER PLANT-(NEW HAVEN,CT)	96
833	Kleen Energy	623
834	BELD - Braintree Electric Linghting (NORFOLK,MA)	115
836	GenConn Power Plant	197
30007	PSNH - Granite State Newington Rockingham Co.NH	403
30009	CASCO BAY	543
30017	Bangor Gas - Bucksport (Orrington)	172
30019	MAINE NATGS	567
30022	Newington Power Meter Station	592
	Total	**9592**

TGP

Meter #	Meter Name	MW
20747	Pittsfield/Bosquet/Altresco	173
20901	Berkshire Power	272
20751	Mass Power-Monson	250
20751	MMWEC-Monson	354
20884	Millenium Power	360
20926	FPLE-Rise	500
20707	OSP 1 and 2	560
20894	IPA-Blackstone/Suez	570
20931	Granite Ridge-Londonderry	720
	Total	**3759**

PNGTS

Meter #	Meter Name	MW
02-0400	Rumford Power	270
02-0450	Jay (Verso)	150
05-0600	Westbrook Energy Center	552
02-0775	Newington-EP	592
02-0900	Newington-PSNH	403
	Total	**1967**

IRQ

Meter #	Meter Name	MW
245206	Stratford	0
281335	Milford B	0
147191	Devon	176
893935	Devon B	197
	Total	**373**