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August 10, 2015

Alexander Speidel
Public Utilities Commission
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Re: IR 15-124 Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire
OCA Comments to July 10, 2015 Memorandum from Staff

On April 17, 2015, the New Hampshire Public Utilities Commission (Commission) issued an Order of Notice opening a non-adjudicative investigation into potential approaches to ameliorate adverse wholesale electricity market conditions in New Hampshire. On July 10, 2015, the Commission Staff issued a memorandum (Staff Memo) addressing whether under New Hampshire law the Electric Distribution Companies (EDC) have "…the 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 its memorandum Staff invites input on or before August 10, 2015. The Office of the Consumer Advocate (OCA) appreciates the opportunity to participate in this docket, and provides the following input as its comments to the memorandum.

I. <u>INTRODUCTION</u>

The problem sought to be addressed in this proceeding relates to the recent winter electricity market price spikes experienced in New Hampshire and much of the rest of New England. One underlying cause of these price spikes is that natural gas-fired generators within the ISO-New England control region generally do not secure contractual terms for firm gas pipeline transportation to their facilities – capacity that becomes constrained when demand is at its peak. The primary concern of the OCA is, whether and to what degree, it is good policy to encourage – or permit - EDCs to procure gas pipeline capacity for the purpose of ameliorating market fluctuations, with the implicit or explicit understanding that the Commission would allow the costs of such gas capacity procurement in electric distribution rates. The OCA urges the Commission to find that such a policy would be speculative with respect to benefits and therefore unduly risky, as the costs may exceed the benefits. There is also the risk of long-term stranded costs should the purchased capacity, under long-term contracts, prove to be uneconomic as excess capacity. OCA cautions that bringing more natural gas to the region in an effort to solve a regional wholesale unregulated *market* problem is a very complex matter, and that the Commission may lack adequate data necessary to support a decision to subject ratepayers to the risks inherent in Staff's proposal. Although Staff is not proposing that the Commission act as a direct market participant, the OCA nevertheless cautions against any Commission encouragement of long-term gas capacity procurement by EDCs, because such a practice could lead to new costs for EDC ratepayers. Ratepayers expect to be responsible for the prudent costs necessary to provide utility service but should not bear the risks of speculative investments in unrelated commodities. Natural gas is not a direct input into the service of electricity distribution. Ultimately, any decision to allow rates for electric distribution ratepayers to include the costs of gas capacity contracts would be subject to legal challenges.

In the Staff memo, Attorney Speidel raises, and analyzes, three separate legal issues pertaining to:

- Whether the restructuring statute prohibits an EDC from acquiring gas capacity, pursuant to RSA Chapter 374-F;
- Whether EDCs have the corporate power to acquire gas capacity pursuant to RSA Chapter 374-A; and
- Whether EDCs could recover the costs, in rates, associated with gas capacity acquisition pursuant to RSA Chapter 378 and related utility ratemaking law.

The OCA will focus chiefly on the third issue, because we believe that it is inappropriate, and possibly unlawful, for the Commission to place in regulated electricity distribution rates the cost of gas capacity acquisition purchased for the purpose of transfer to third parties that operate in a competitive market. Inherent in the proposal favored by Staff is a fundamental opportunity for EDCs to take risks with ratepayer-owned funds and a fundamental risk for all of its ratepayers whereby they would pay excessive rates that reflect costs for gas capacity acquisition that is neither used and useful nor prudently incurred, with respect to electricity distribution service. The OCA opposes the Staff's analysis with respect to the third issue, and further, the OCA urges the Commission to reject the overall proposal supported in Staff's memo, based on regulatory principles and economic principles[1].

A. The Electric Utility Restructuring Statute (RSA Chapter 374-F)Does Not Support EDCs Acquisition of Gas Capacity?

The specific issue of whether gas capacity may be procured by EDCs is not explicitly addressed in the restructuring statute. However, given the primary purpose of the restructuring statute -- the separation of generation, from distribution service in a highly regulated market -- it can reasonably be inferred that the purchase of gas capacity by EDCs for the purpose of affecting prices in the deregulated wholesale electricity supply market, would be prohibited as being fundamentally in conflict with the Legislature's intent when it enacted the restructuring statute. For example, among the statute's explicit directives are:

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[1] With respect to economics, the memo states: "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.

- Generation service should be subject to market competition and minimal economic regulation

"Market competition" and "minimal economic regulation" as used in the statute, implies that a market that operates freely, based upon profit-seeking market participants, should not be unduly subject to distortions that come from governmental interference. However, Staff's proposal would ultimately create a scenario where the Commission would allow – or encourage by prior authorization – regulated utilities to procure fuel for unregulated wholesale market generators for the express purpose of influencing the prices in that deregulated market for electricity generation. In allowing such utilities to recover the costs of that intentionally market-influencing gas capacity procurement, and thereby shifting the risks from participants in a free market toward captive customers of monopoly EDCs as guarantors of the procurement costs, the Staff proposal potentially undermines the essential elements of the free market that the Legislature intended to create. In that context, the restructuring statute can reasonably be seen as prohibiting EDCs from acquiring gas capacity for the purpose of influencing prices in the mostly divested generation market. Attorney Speidel said it well when analyzing the contrasting argument to his recommendation.

His memo acknowledged that, since gas capacity acquisition certainly does not fall within the restructuring statute's exception allowing EDC ownership of small scale distributed generation resources, the Commission may determine that the primary restructuring policy principle – ("market competition and minimal economic regulation") may reasonably cause the Commission to 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". *Staff Memo at 2.* The OCA believes that the Commission *should* so conclude. Therefore, with respect to the first legal issue presented in the Staff Memo, the OCA recommends that the Commission find that EDCs *are* prohibited by the restructuring statute, from procuring gas pipeline capacity for purposes of providing such capacity to wholesale electric generation market participants in order to affect their prices.

The OCA further observes that the proposal to incur new costs to ameliorate wholesale price spikes is fundamentally at odds with certain basic policy principles even if it did not directly violate a statute. First, it would be ironic to encourage the re-engagement of EDCs in the supply market, after many years of expenditure of substantial resources by the New Hampshire Legislature and the Commission (continuing to this day with respect to PSNH/Eversource), working toward the creation of an *unregulated* competitive market for electricity supply *discrete* from the transmission and distribution services of the State's EDCs, i.e., divestiture. Inherent in the creation of any competitive market is the acceptance that prices will fluctuate according to unpredictable market forces. It is potentially the worst case scenario to remove authority over an industry with monopoly characteristics based on reliance upon market forces taking over the role of efficiency and pricing discipline, but then, in an attempt to ameliorate prices from that competitive market, nonetheless enlist ratepayers as a guarantor of yet new types of risky long-term costs that may *raise* the rates of their monopoly distribution service. Even though the Commission retains authority over the energy supply market as it pertains to the functions of EDCs that offer default service, monopoly distribution rates should remain separate, and insulated, from the electricity supply market. The former, under New Hampshire law, must be based on costs of service resulting from prudent investment in rate base that is used and useful for *distribution* of electricity. Such distribution service ratemaking should be insulated from the price fluctuations inherent in the electricity supply market. Staff's proposal potentially contaminates distribution rates with unrelated costs, and the uncertainties of unregulated energy supply markets.

Second, as a matter of economics and cost/benefit analysis, the Commission must consider the risks of Staff's proposal. The proposal would attempt to address future potential high prices by incurring new long-term costs that are above and beyond the costs necessary, or used and useful, in the provision of regulated electric service. The OCA believes that such risks outweigh the uncertain benefits of the proposal, especially because various assumptions would have to be borne out before any of the sought-after- benefits would materialize.

While Staff explicitly did *not* address the economic issues that it acknowledges to be necessary as a foundation for the Commission's determinations in this matter, the OCA observes that the Staff proposal nonetheless rests upon a number of uncertain economic assumptions. The proposal that is potentially supported by Staff's Memo, appears to make the following assumptions:

- An EDC will have the ability to procure natural gas pipeline capacity under economic arrangements that are substantially better than what is otherwise available to unregulated merchant electricity generators;
- An EDC could effectively and efficiently transfer the newly procured natural gas pipeline capacity to unregulated merchant gas-fired electric generators at prices that are substantially lower than market prices otherwise available to those generators;
- The merchant generators will pass along any savings from reduced cost gas pipeline capacity in a way that will benefit all of the ratepayers of the EDC. While we presume that this assumption could be made operational through bi-lateral contracts, the Staff Memo is silent on this mechanism.

Staff also suggests a potentially separate path that would allow EDCs to seek authority for gas capacity acquisition in the context of their provision of Default Service, quoting RSA 374-F:3, V(e), i.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.

The OCA first observes that this alternative proposal is less controversial because it would apply to the ratemaking for energy supply rates and not monopoly distribution rates. However, the OCA would remain skeptical that the proposal might fail to "minimize customer risk", fail to avoid "harm to the development of competitive markets", and fail to "mitigate against price volatility without creating new deferred costs". All of these risks remain inherent in the proposal and, if such risks are found to exist, it appears that this portion of the restructuring statute may not be an appropriate path by which EDCs could lawfully be authorized to embark on a plan to acquire gas pipeline capacity for the purposes proposed in Staff's memo.

B. It is Unwise To Risk Incurrence of Long-Term Costs In Order To Address Recent Short-Term Price Spikes In a Deregulated Wholesale Market

The Staff proposal appears to assume that recent market price spikes represent a long-term phenomenon that will not be worked out by the very market forces that have been intentionally unleashed by State policy over the last decade. Policy-makers have chosen to trust the market over regulatory mechanisms as they relate to the generation market. Therefore, that policy should, at least, be given a chance to prove itself over a time period of more than a few years. Given that the long-term risk of stranded costs from the proposed investments are not seriously discussed or analyzed in Staff's Memo, there is the appearance of a presumption that EDC investment in gas pipeline capacity would necessarily be economically beneficial and not result in stranded costs. If that is an assumption, it needs to be thoroughly examined before allowing this process to unfold. In its memo, Staff fails to explain why electric generators themselves do not procure fixed long-term gas pipeline capacity at stable prices. There needs to be a more thorough explanation of the market failure that is sought to be rectified by the sort of proposals being discussed in Staff's Memo. Staff fails to explain why an EDC, acting as a proxy for such merchant generators, would solve the original market problem identified in this docket.

To be fair, Staff readily discloses that its memo does not address the *advisability* of an EDC making investments in gas pipeline capacity in an attempt to ameliorate electric rates for its customers. The OCA observes that neither does Staff indicate that any EDC has already expressed an affirmative desire to make such investments. The Commission could choose to reserve consideration of this issue to the day when an EDC files a petition seeking approval for gas capacity acquisition, backed by the opportunity to place such costs in rates paid by electric distribution customers. In the event that such a petition is filed, the OCA would recommend against advance assurances that the Commission would deem such investments as prudent or used and useful, as required by fundamental regulatory principles.

C. The Proposal Fails to Ensure That Those Incurring Costs Will Receive Benefits

While Staff attempts to justify potentially costly and long-term investments in gas pipeline capacity based upon predicted savings to all electricity ratepayers, that justification is not demonstrated. Even assuming that the proposed investments could be linked to direct savings in default energy supply that EDCs must procure for purposes of default service to some, but not all, of their customers, the Staff proposal goes much farther in suggesting that the benefit somehow also flows to customers of monopoly electric distribution service, based on the theory that all electricity customers purchase energy supply from somewhere, and that all customers will benefit from the capacity contracts promoted in Staff's proposal. Accordingly, Staff suggests that the costs of new investments in gas pipeline capacity could lawfully be put into the rates of distribution service customers of EDCs. However, it is highly uncertain that such customers can be shown to benefit - and to what degree - from the gas capacity costs that could be placed into EDC distribution rates. Such benefits, if they exist at all, would be impossible to quantify. Absent reliable quantification, no appropriate cost/benefit analysis to support the proposal is possible. Moreover, even assuming *arguendo*, that benefits were to follow all customers, there is no regulatory principle that authorizes a surcharge on utility bills to re-capture the value of benefits obtained by an indirect market-related action of the utility, especially where the action involves purchase of capacity for transportation of a fuel that is not used in the production of the service of the EDC itself.

It is a tenuous theory that energy prices in the wholesale electricity market will necessarily benefit from the acquisition of gas pipeline capacity by an EDC. Perhaps Staff has in mind certain contractual arrangements that would govern or secure lower prices offered by such unregulated generators, but Staff has not provided any detail about the specific mechanism whereby benefits would materialize. Moreover, even if it were assumed to be true that non default-service distribution customers were to somehow indirectly benefit from the gas capacity acquisition of an EDC that does not necessarily suggest that it would be appropriate – or lawful - to assign higher rates to customers of a different (regulated) service, i.e., electricity distribution service. Under similar logic, could the Commission authorize a surcharge for customers of all gas purchasers in the State, based on the assumption that they derived a benefit in the cost of gas, as a result of EDC investment in gas pipeline capacity? It could be a slippery slope toward imposing surcharges on any customer for a presumed, but possibly non-existent, hoped-for benefit.

II. THE MAINE ENERGY COST REDUCTION ACT

Staff's Proposal Appears to be Similar To the Purposes Underlying The Maine Energy Cost Reduction Act, Recently Enacted in Maine – but Staff Has Not Recommended the Various Safeguards Incorporated in the Maine Legislation, and by the Maine Commission

The OCA is not taking a position that the Legislature or the Commission adopt a program similar to the Maine Energy Cost Reduction Act[2]. However, in the event that the Commission were interested in pursuing an analogous proposal for New Hampshire, actions of this sort initially should be authorized by the Legislature, because it represents a significant departure from traditional Commission authority and ratemaking principles. For purposes of this proceeding, it is worthwhile to review the terms of Maine's legislation, and a recent analysis of the application of that legislation by the Maine Staff, because such a review underscores many of the risks and uncertainties underlying the similar concept proposed by Staff's Memo under consideration here. Similarly, it is worthwhile for the Commission to review a recent critique of the new Maine policies whereby the State is promoting the purchase of gas pipeline capacity. The Maine legislation is summarized by the Maine Staff as follows:

[2] 35-A M.R.S. §1901

During its 2013 session, the Maine Legislature enacted The Maine Energy Cost Reduction Act, P.L. 2013, c.369, codified at 35-A M.R.S. § 1901 *et seq* (Act). The Act contains the finding that the expansion of natural gas transmission pipeline capacity into Maine and other states in the New England could result in lower natural gas prices and, by extension, lower electricity prices for consumers in Maine To facilitate the expansion of natural gas transmission pipeline capacity into the region and the State, the Act authorizes the Commission, in consultation with the Public Advocate and the Governor's Energy Office, to execute an Energy Cost Reduction Contract (ECRC) in accordance with the provisions of the Act. 35-A M.R.S.§1904. The Act limits the amount of ECRCs to a cumulative total of no more than 200,000,000 cubic feet per day (200 MMcf/d) or 200,000 dekatherms per day (Dth/d) of natural gas capacity or for a total cost that does not exceed $75,000,000 annually.1 Pursuant to the Act, the Commission may also negotiate and enter contracts for the resale, evaluation and administration of pipeline capacity acquired through an ECRC, and is responsible for assessing, analyzing, negotiating, implementing and monitoring compliance with ECRCs. 35-A M.R.S. §1906. The Commission may not execute an ECRC after December 31, 2018, but may continue to administer existing contracts and enter resale agreements for capacity purchased prior to that date. Before the Commission may execute an ECRC, it must have pursued, in the appropriate regional and federal forums, market and rule changes that will reduce the basis differential2 cost for natural gas delivered into New England and increase the efficiency with which gas brought into New England and Maine is distributed and used. 35-A M.R.S. §1904(1)(A). The Commission may not execute an ECRC if it concludes that: 1) market and rule changes will, within the same timeframe, achieve substantially the same cost reduction effects for Maine electricity and gas customers as the execution of the ECRC; and 2) private transactions will achieve, within the same timeframe, substantially the same cost reduction effects for Maine electricity and gas customers. 35-A M.R.S. §1904(1)(A) and (B). The Act also requires the Commission, in consultation with the Public Advocate and the Governor's Energy Office, to retain the services of a consultant with expertise in natural gas markets to make recommendations regarding the execution of an ECRC. To enter into an ECRC or direct a utility to do so, the Commission must determine in an adjudicatory proceeding that the proposed ECRC is commercially reasonable and in the public interest, and that the contract is reasonably likely to accomplish the following objectives:

1. to materially enhance natural gas transmission pipeline capacity into the State or into the Independent System Operator of New England (ISO-NE) region;
2. that the additional capacity it provides will be economically beneficial to Maine's electric consumers, natural gas consumers, or both;
3. that the overall costs of the contract are outweighed by its benefits to Maine's electric consumers, natural gas consumers, or both; and
4. to enhance electrical and natural gas reliability in the State. 35-A M.R.S. §1904(2).[3]

[3] Maine Public Utilities Commission, Examiners' Report, Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. §1901, October 1, 2014.

III. NEW HAMPSHIRE LAW GOVERNING RATEMAKING PRECLUDES RECOVERY OF COSTS FROM ELECTRICITY DISTRIBUTION CUSTOMERS OF AN EDC.

Even assuming traceable market-based economic benefits from gas pipeline capacity procurement by EDCs, the Staff proposal would still face legal issues which, in the view of the OCA, would preclude the proposal to include such costs in rates as contrary to New Hampshire law governing ratemaking.

The New Hampshire Supreme Court describes "two broad principles" which govern the development of utility ratebase. *Appeal of Conservation Law Foundation of New England, Inc.,* 127 N.H. 606. The Court holds that prudency "…requires the exclusion from rate base of costs that should have been foreseen as wasteful." *Id. citing LUCC v. Public Serv. Co. of N.H,* 119 N.H. 332, 343 (1979); *Company v. State*, 95 N.H. 353, 360 (1949); and *S. W. Tel. Co. v. Pub. Serv. Comm.*, 262 U.S. at 289. The Court continues, "If the entire investment in a given asset was foreseeably wasteful, the entire investment must be excluded; if only some of the constituent costs attributable to a given asset were foreseeably wasteful, the value for rate base purposes of the investment in this asset must be reduced accordingly. *Id. citing Glicksman*, Allocating the Cost of Constructing Excess Capacity: "Who Will Have To Pay For It All?", 33 Kan.L.Rev. 429, 432 (1985) (footnote omitted).

In addition to prudence, a utility must demonstrate that its investment, or addition to rate base, is "used and useful," before being authorized to earn a return on any prudently incurred investment. RSA 378:28 ("The commission shall not include in permanent rates any return on any plant, equipment, or capital improvement which has not first been found by the commission to be prudent, used, and useful.").

The distinction between prudence and "used and useful" is significant. The New Hampshire Supreme Court states:

> "[t]he second principle of rate base inclusion or exclusion derives directly from the statutory description of allowable rate base property as "used and useful." RSA 378:27, :28. …While prudence judges an investment or expenditure in the light of what due care required at the time an investment or expenditure was planned and made, usefulness judges its value at the time its reflection in the rate base is under consideration. Under the "used and useful" principle, the commission is not asked to second-guess what was reasonable at some time in the past, but rather to determine what can reasonably be done now with the fruits of investment.

Appeal of CLF, 127 NH 606 (1986) at 637-638.

Simply stated, "The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to a return." *Western Massachusetts Electric Company*, D.P.U. 85-270 at 25-27 (1986). Similarly,

> The principle of prudence entails the uncertainty that is inherent in any backward-looking judgment, and the principle of usefulness is commonly described as allowing a rate-setting commission substantial flexibility for pragmatic judgments about what should or should not be regarded as useful. See *Appeal of CLF,* at 673-74. This flexibility mirrors the need to

> provide an opportunity for the exercise of expert judgment in giving due recognition to the two competing interests that come to the fore in any contested rate proceeding, the interests of investors who would like a guaranteed return on any investment and the interests of customers who would like low rates.

Appeal of Gary McCool, 128 N.H. 124 (N.H. 1986), at 141-142.

Property not devoted to the production and delivery of energy to the consumer is not includible in the rate base. *See* I A. Priest, *Principles of Public Utility Regulation* (1969), at 174. Investment in gas pipeline capacity is a speculative investment in a fuel that is not used by the investing utility, which is currently in the process of *divesting* itself of generation assets. That makes the investment more of a financial hedge than a necessary utility investment suitable for inclusion in rate base. It is a risky investment, for which Staff's potential proposal would shift the risks from investors to ratepayers. Gas capacity, on its face, is not useful in distributing electricity. Whether it is a sound financial investment to affect the market price of electricity is a question that cannot be answered at this time – it represents a risky financial gamble. In either case, it is a substantial departure from the traditional regulatory principle that rates reflect investments that are used and useful in providing actual service. Especially in the absence of enabling legislation the OCA recommends that the Commission refrain from embarking on this departure from traditional regulatory principles, in part, because it would rest on shaky legal grounds.

Applying these basic regulatory principles to the instant matter, it appears that it would be extremely difficult for any EDC to demonstrate, while meeting its burden of proof in the context of a rate proceeding, that past investments in gas pipeline capacity – a product that is literally not even used by any EDC – are investments that are useful in the provision of electric distribution service. Such a finding, and inclusion in utility distribution rates, absent legislative authorization, would appear to be unlikely and, if granted, subject to reversal by the Court. Moreover, even with respect to prudence, in a retrospective review of the wisdom of incurring substantial costs of acquiring pipeline capacity that is not needed by the purchasing utility, it appears that the Commission would be compelled to find imprudence, given the known risks, (such as those articulated here) even at the time of the acquisition.

IV. CONCLUSION

Staff's proposal is a well-intentioned recommendation aimed at the perceived market problem whereby pipeline capacity constraints appear to create excessive increases in the cost basis of natural gas in New England, compared to the index prices prevailing in the production areas and in areas of larger markets. However, this problem is a complex one, and OCA advises caution against incurring significant costs in the hopes of affecting the price outcome in the complex and unregulated regional wholesale electricity market. At the very least, any attempt to accomplish such a thing should be done only in concert with other New England states and with the guidance and cooperation of the regional grid operator, ISO-New England. Finally, the Staff proposal presents a significant legal issue. The Commission should not adopt such a significant departure from its traditional authority without enabling legislation as a pre-condition, as was done in Maine.

The Commission should also take note of the recent expert study sponsored by the Maine Commission, which is apparently exercising caution before acting upon its new legislative authorization to use ratepayer-backed resources to increase demand for regional gas pipeline capacity. The results of that report (by London Economics International LLC) demonstrate the risks that are inherent in the type of proposal that is suggested in Staff's Memo. Please see Attachment 1. That critique indicates that a careful cost/benefit analysis suggests that the subject policy is unsound. A news report on that independent analysis can be found here: http://www.centralmaine.com/2015/07/15/consultant-maines-75-million-plan-to-boost-natural-gas-too-expensive/

Respectfully,

Susan Chamberlin

Susan W. Chamberlin
Consumer Advocate

cc: Service List electronically

OCA Comments
IR 15-124
Attachment 1

REDACTED PUBLIC VERSION

Maine Energy Cost Reduction Act: Cost benefit analysis of ECRC proposals

June 20, 2015

Prepared for

Maine Public Utilities Commission staff

by

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Abstract

London Economics International LLC ("LEI") has been engaged by the Maine Public Utilities Commission (the "Commission", or "MPUC") to assist in the Commission's Docket No. 2014-00071 "Investigation of the Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act." The Maine Energy Cost Reduction Act ("MECRA") authorizes the Commission to execute an energy cost reduction contract ("ECRC"), a contract executed to the specification of MECRA to procure firm transmission ("FT") capacity on a natural gas transmission pipeline. The criteria for entering into ECRC(s) are, broadly, whether the benefits to Maine of contracting for firm gas transmission capacity (in terms of lower natural gas prices and associated lower power prices) outweigh the costs of such contracts. The Commission staff has asked LEI to perform an independent cost benefit analysis of each ECRC proposal, to inform the Commission's determination as to whether sufficient benefits will result to Maine consumers of natural gas and electricity to warrant entering into an ECRC. This includes analysis of the ECRC proposals' net benefits.

Under LEI's Baseline outlook for New England, which is driven by "business as usual" conditions in the wholesale electricity market (such as no change to power market design, and use of ISO-NE's 50-50 weather normal demand forecast, rational new investment in generation, a build out of pipeline projects that are sufficiently far along in the development such that they have firm commitments, and "normalized" weather assumptions for both gas demand in the region), none of the individual ECRCs provide benefits greater than its cost. The benefits considered in the analysis include: reductions in the wholesale cost of gas to Maine residential, commercial, and industrial consumers; reductions in the wholesale cost of power to Maine residential, commercial, and industrial consumers; and the resale value of firm transportation ("FT") rights for each of the ECRCs.

LEI's findings do not imply that the gas pipeline projects that underpin the ECRCs are necessarily un-economic or represent poor investment decisions for the parties that have engaged in them. The benefits to Maine do not outweigh the costs primarily because there are many other consumers that are beneficiaries of the market-wide impacts created by the reduced natural gas prices by the ECRCs. However, those beneficiaries would not be paying for the ECRCs. Maine's gas and electric consumption profile is a small portion of the New England region. Therefore it is not surprising that relative to bearing 100% of the cost of an ECRC, the benefits to Maine are too small to offset the cost of firm transportation.

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1 Summary of key findings

In 2013, the Maine legislature passed the Maine Energy Cost Reduction Act ("MECRA").[1] The Act was a result of increasing concerns about sufficiency of natural gas deliverability in the New England region. The legislature's concern stemmed from the very high spot natural gas and accompanying high wholesale power prices during wintertime. Demand for natural gas in New England pushed up against the limits of gas pipeline capacity during the markedly colder-than-normal winter of 2013-2014. As heating loads surged, local gas distribution companies ("LDCs") utilized all their firm pipeline transmission capacity, leaving little interruptible capacity available for power plants. A complex mix of factors including weather, daily and intra-day patterns of gas and power demand, availability of pipeline gas, availability and price of alternative power fuels such as liquefied natural gas ("LNG") and fuel oil, as well as institutional factors such as power market rules and regulations all contributed to the price outcomes in that winter.

Natural gas price spikes impact nearly all electric power customers in New England.[2] Natural gas plants are on the margin, setting the price of power in New England, for many hours of the year. Over the past 15 years, gas power generating capacity has increased from 18% to 44% of New England's total power capacity of 31,000 megawatts ("MW").[3]

Furthermore, not just cost, but reliability became a concern in recent years for ISO-NE operations, as gas-fired power plants that could not get fuel could not run and produce electricity. For example on January 28, 2014, according to ISO-NE, gas-fired generators produced only about 3,000 MW during the peak demand hour, although there was more than 11,000 MW of natural-gas generating capability nominally available.[4]

1.1 Legislation authorizes MPUC to look into procuring firm gas transmission capacity

MECRA authorized the Commission to execute an energy cost reduction contract ("ECRC").[5] An ECRC is a contract executed to the specification of MECRA to procure firm transmission ("FT") capacity on a natural gas transmission pipeline (including compression capacity).

Before it executes such a contract, the legislation requires the Commission to:

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[1] State of Maine. *Maine Energy Cost Reduction Act* in 35-A M.R.S.§1904(2). 2013.

[2] Some New England retail customers of electricity are hedged from spot wholesale energy prices by long-term contracts and therefore not impacted by spikes in electricity customers- in Maine, this is about 4% of customers. Sources: ISO-NE. CELT Forecasting Details: 2014. <http://www.iso-ne.com/trans/celt/fsct_detail/index.html>; PPA contract data from SNL; and FERC filings.

[3] ISO-New England. http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix.

[4] Brandien, Peter. Technical Conference on Cold Weather Operations. ISO New England / Federal Energy Regulatory Commission. April 1, 2014. Speaker.

[5] State of Maine. *Maine Energy Cost Reduction Act* in 35-A M.R.S.§1904(2). 2013.

- Pursue changes to market rules that would reduce the basis differential for New England gas.[6] If the Commission determines that such rule changes could achieve substantially the same cost reductions in the same time frame as an ECRC, the Commission is not authorized to execute an ECRC.
- Explore all reasonable opportunities for private sector participation in securing additional gas pipeline capacity. If the commission determines that private transactions could achieve substantially the same cost reductions in the same time frame as an ECRC, the Commission is not authorized to execute an ECRC.
- Hire a consultant with expertise in natural gas markets to make recommendations regarding the execution of an ECRC.

After the requirements above are satisfied, the Commission must determine that any ECRC it proposes to enter into is commercially reasonable and in the public interest, and that the contract is reasonably likely to accomplish the following objectives:[7]

- To materially enhance natural gas transmission pipeline capacity into the State or into the ISO-NE region;

- That the additional capacity it provides will be economically beneficially to Maine's electric consumers, natural gas consumers, or both;

- That the overall costs of the contract are outweighed by its benefits to Maine's electric consumers, natural gas consumers, or both; and

- To enhance electrical and natural gas reliability in the State.

The economic benefits to Maine consumers noted above would be expected take the form of lower gas prices (reduced basis differentials between New England prices and supply-area prices) which would translate into lower wholesale energy prices. MECRA specifies that ECRCs cannot total more than 200 million cubic feet per day ("MMcfd") feet of gas annually, or a total amount of $75 million annually.

1.2 To be accepted, an ECRC must provide net benefits to Maine gas and power consumers

The Commission established a cost benefit criteria for quantitative analysis of any proposed ECRCs in the Commission's November 13th 2014 Order ("November 13th Order").[8] As stated in the November 13th Order, the Commission's primary evaluation criteria is the net benefits to Maine gas and electricity ratepayers. Benefits include gas price impacts to Maine gas customers; electricity price benefits to Maine electricity customers, and any cost-mitigating impacts, for

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[6] "Basis differential" refers to the difference in natural gas prices at two trading points or hubs. In this case, the hubs of interest are the Algonquin Citygate hub in New England, and receipt point hubs such as Mahwah/Ramapo in New Jersey/New York.

[7] State of Maine. *Maine Energy Cost Reduction Act* in 35-A M.R.S.§1904(2). 2013.

[8] Maine Public Utilities Commission. Order - Phase 1. *Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act*, 35-A M.R.S. §1901. November 13, 2014.

example, the offset value from the resale of capacity (driven by incentives for arbitrage), as enumerated in the November 13th Order. In addition, per the November 13th Order, benefits are to be estimated over a ten-year period; while the costs are to be calculated over the entire FT contract commitment period. The Commission excluded consideration of any broader economic effects of lower gas and energy prices within the mandated cost-benefit analysis.

1.3 Three ECRC bidders submitted a variety of proposals

In December 2014, the Commission received proposals from three bidders for ECRCs, pursuant to the November 13th Order. Some bidders provided more than one proposal; some proposals provided more than one financial bid for FT reservation rate and/or more than one option for primary receipt points or delivery points. Figure 1 shows several key characteristics of each proposal.

More detail of the characteristics of each proposal can be found in Appendix A. Much of the information related to these proposals is confidential and under protective order(s). This information appears in Docket No. 2014-00071 as of March 19, 2015 and remarks and presentation material provided in conference calls and meetings with representatives from Tennessee Gas Pipeline, LLC and Kinder Morgan ("TGP" or "TGP/KM"), Portland Natural Gas Transmission System ("PNGTS"), and Spectra Energy ("Spectra").

1.4 Methodology for estimating project benefits

Estimating the benefits of an ECRC requires a projection of gas and electricity prices in a world without the ECRCs as well as under a set of cases with the ECRCs in place. LEI therefore began the analysis by creating a Baseline outlook for gas and electricity prices. Then, LEI analyzed how each ECRC proposal selected for evaluation impacted gas prices and as a result wholesale electricity prices in New England (and specifically for Maine consumers).

Figure 1. ECRC proposals, key characteristics

Bidder	Spectra Energy	Spectra Energy	PNGTS	TGP/KM
Project name	Atlantic Bridge	Access Northeast	Continent to Coast ("C2C")	Northeast Energy Direct ("NED")
Project size, dekatherms per day ("Dth/d")	220	[redacted]	[redacted]	1,200
Size of ECRC offered, Dth/d	[redacted]	80	up to 200	[redacted]
Will it go forward without ECRC?	yes	yes, if PUC approval for electric distribution utilities	[redacted]	[redacted]
Greenfield/Brownfield?	Brown	Brown	Brown	Green+brown
Developer's projected in-service date	Nov-17	Nov-18	Nov-17	Nov-18
Financial bid ($ per Dth/d)	[redacted]	[redacted]	[redacted]	[redacted]
Primary receipt point(s) corresponding to financial bid noted above	Mahwah, Ramapo	Mahwah, Ramapo	Wright	Wright
Minimum term (years)	15 AGT; 2 M&NP	[redacted]	15	[redacted]

Sources:

Atlantic Bridge: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit E "Non-binding Term Sheet Atlantic Bridge Firm Transportation Service;" "Rate Schedule AFT-1 Firm Transportation Service;" and conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

Access Northeast: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit A "Rate Schedule ERS Electric Reliability Service;" Exhibit B "Non-binding Term Sheet Access Northeast Project-Electric Reliability Service;" and conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

C2C: MPUC Docket No. 2014-00071, File No. 213: PNGTS. "ECRC Proposal December 5, 2014, PNGTS C2C Project;" conference call/meeting with PNGTS, LEI, Commission staff, February 5, 2015.

NED: MPUC Docket No. 2014-00071, File No. 212: TGP. "ECRC Proposal of Tennessee Gas Pipeline Company LLC," December 4, 2014; Attachment A-2 "Precedent Agreement;" Attachment 2 "Overview of the Offer;" File No. 263. Appendix B to "Negotiated Rate Agreement."

1.5 Key finding: No ECRCs provide positive net benefits to Maine

LEI's key finding is that none of the individual ECRCs provide benefits greater than the contract costs. The benefits we included in the analysis were net present value ("NPV") totals of 10-year reductions in the cost of gas to Maine residential, commercial, and industrial consumers; NPV of 10-year reductions in the cost of power to Maine residential, commercial, and industrial consumers; and the 10-year NPV of resale value of FT rights for each of the ECRCs (see Figure 2). The cost of each ECRC is the net present value of the reservation cost (reservation rate times contracted capacity) for FT over the proposed term of each ECRC. Contracted capacity and reservation rates are discussed in more detail in Section 5 and in Appendix A.

Figure 2. Net benefits of ECRCs (NPV, million 2015 dollars, 9% discount rate)

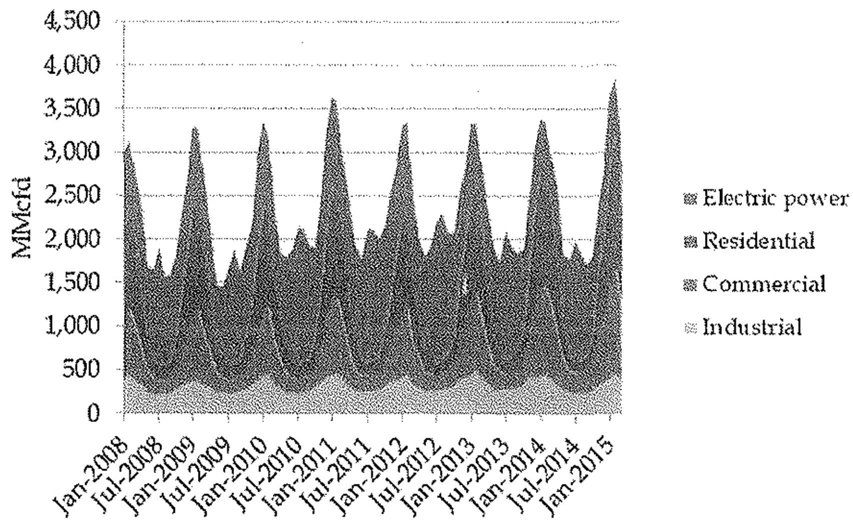
ECRC	Potential resale value	Reduction in retail gas costs	Reduction in retail energy costs	Total benefits	Reservation cost of ECRC	Net benefits
Atlantic Bridge	[redacted]	$ 49	$ 87	[redacted]	[redacted]	[redacted]
Access Northeast	[redacted]	$ 41	$ 73	[redacted]	[redacted]	[redacted]
C2C Dawn	[redacted]	$ 32	$ 56	[redacted]	[redacted]	[redacted]
C2C Niagara	[redacted]	$ 32	$ 55	[redacted]	[redacted]	[redacted]
C2C Wright	[redacted]	$ 30	$ 50	[redacted]	[redacted]	[redacted]
NED	[redacted]	$ 38	$ 64	[redacted]	[redacted]	[redacted]
NED A	[redacted]	$ 50	$ 85	[redacted]	[redacted]	[redacted]

Our findings do not imply that some or all of the gas pipeline projects that underpin the ECRCs are necessarily un-economic or represent poor investment decisions for the private sector parties that have engaged in them. As we will demonstrate in this report, the benefits to Maine are small because Maine simply does not use large amounts of gas and electricity. Further the benefits of the ECRCs flow through to other gas and electricity consumers in New England. But those other beneficiaries would not be responsible for the costs of the ECRCs. Relative to 100% of the cost of an ECRC, the benefits are too small for Maine and cannot offset the cost of firm transportation to Maine.

1.6 Roadmap for this report

We begin this report by providing context for the reader--a brief overview of gas and power consumption in Maine and in New England more broadly.

Figure 4. Natural gas consumption in New England, by sector (monthly 2009-2015)



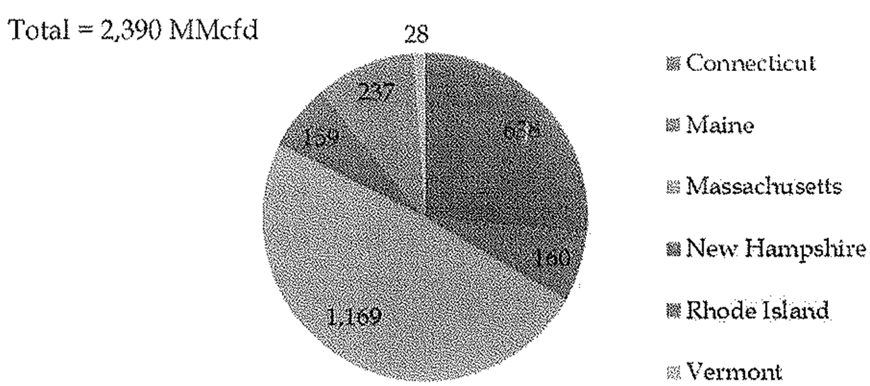
Source: EIA.

2.1 Maine is a small consumer of gas and power compared to the rest of New England

At about 160 MMcfd, Maine's gas consumption was about 7% of total New England gas consumption in 2014 (see Figure 5). Of that 160 MMcfd, about 10.9 MMcfd (on an annual basis) is under long-term contract and therefore not exposed to spot market prices.[9]

[9] Information provided by Maine Public Utility Commission.

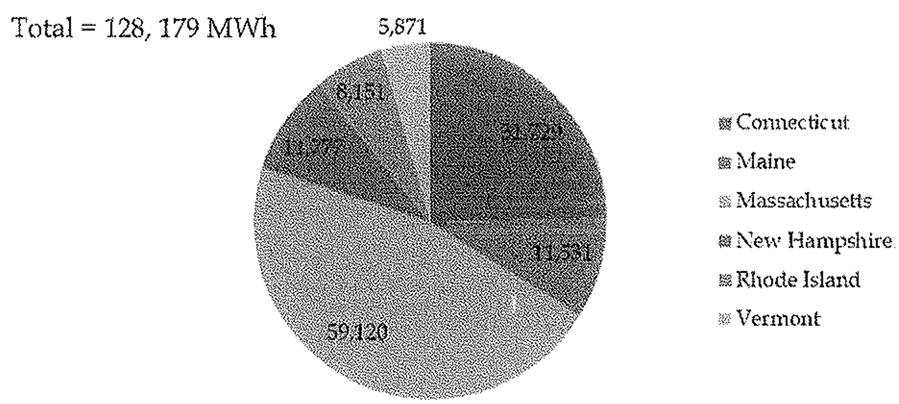
Figure 5. New England natural gas consumption by state, 2014 (MMcfd)



Source: EIA. Total may not equal sum of components owing to independent rounding.

Maine's electric energy consumption is about 9% of the total consumption in New England (see Figure 6). About 4% of Maine's consumption is not exposed to wholesale energy prices because of the existence of long term contracts.[10]

Figure 6. New England electric power consumption by state, 2014 (MWh)



Source: ISO-New England and LEI. Total may not equal sum of components owing to independent rounding.

[10] Sources: ISO-NE. CELT Forecasting Details 2014. <http://www.iso-ne.com/trans/celt/fsct_detail/index.html>; PPA contract data from SNL; and FERC filings.

Because Maine's consumption of gas and electric energy is small relative to New England as a whole, the impacts of potential changes in gas or energy prices on the total cost of gas and energy in Maine are small compared to impacts on other states. For example, if natural gas prices declined by $0.25 per MMBtu, it would reduce the annual cost to gas consumers (including power plants) in Maine by $14.6 million (i.e., $0.25 per MMBtu * 160 MMcfd * 365 days) assuming consumption was at 2014 levels. But it would reduce costs to Massachusetts consumers by much more: $106.7 million (i.e., $0.25 per MMBtu * 1,169 MMcfd * 365 days) assuming no retail hedges. The benefits to Maine would be only about 1/7 of the benefits to Massachusetts.

The next sections of this report provide LEI's Baseline outlooks for New England gas and energy prices, and quantify the projected reductions in gas and energy prices that could result from Maine entering into ECRCs for new pipeline capacity, and the benefits to Maine of the lower gas and power prices.

3 Baseline outlook for gas and electric energy costs

The MECRA Baseline outlook results provide the baseline to which the benefits of each ECRC are compared. The MECRA Baseline outlook represents LEI's view of gas availability and gas and electricity prices in New England under a "business as usual" outlook, if Maine does not enter into an ECRC. This outlook assumes normalized weather; it assumes gas pipelines that already have firm contractual commitments are built in the Northeast United States and New England; it assumes rational power plant retirements and new entry based on fundamentals and current market rules. More detail about data, assumptions and rationale for the assumptions used in the MECRA Baseline outlook can be found in Appendix B.

To generate the MECRA Baseline gas and energy price outlooks, LEI combined a widely-used industry standard network model of the North American gas grid (known as GPCM) with LEI's proprietary simulation model of the ISO-NE wholesale electricity market (POOLMod). The details of the modeling approach can be found in Appendix B. To model the impact of each of the ECRCs, all assumptions were held constant except the gas pipeline expansion related to the ECRC, as will be discussed in Section 4.

3.1 MECRA Baseline outlook for New England gas prices

LEI produced a Baseline gas price forecast for New England (Algonquin Citygate prices) and for the primary receipt points specified in the ECRCs (Mahwah, Niagara, Dawn, and Wright). LEI uses Algonquin Citygate prices to represent New England gas prices in our analysis because pricing is liquid and transparent at that hub. There are other traded hubs in New England, such as Dracut; prices there would be close to Algonquin Citygate prices in any case, and not make a material difference to our outlooks. LEI's MECRA Baseline outlook shows Algonquin prices declining dramatically in 2017 (see Figure 7 and Figure 8). This decline is the result of our assumption that the TGP CT (in November 2016), AIM (in November 2017) and the Atlantic Bridge non-ECRC component at 110,000 Dth/day (in November 2017) capacity expansions come into service as projected by their developers. These three gas infrastructure projects are included in the Baseline outlook because they have firm commitments from shippers. The price of Henry Hub gas is included in the figures, as it is a widely-used and familiar benchmark for North American gas prices. In addition, the Leidy hub price is included as benchmark for the fast-growing and low-cost Marcellus shale gas that lies geographically close to New England.

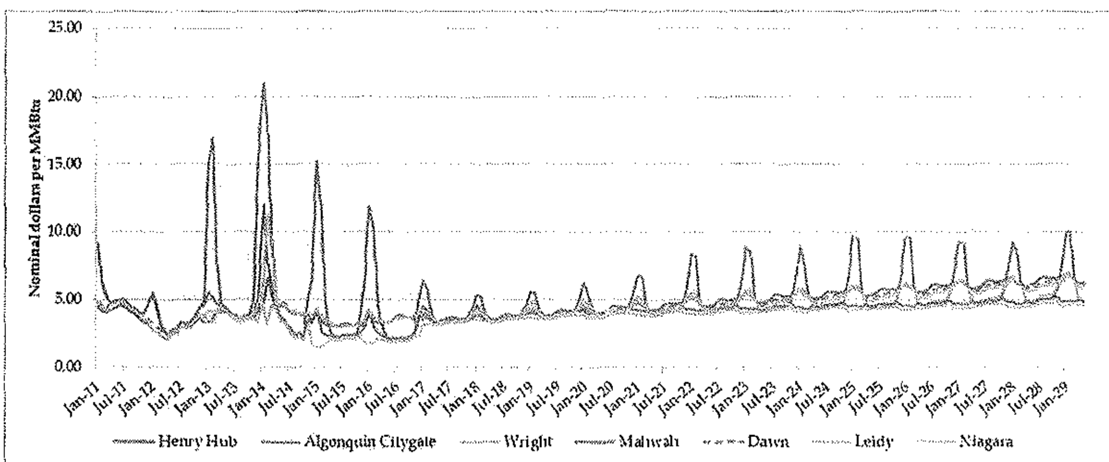
There are several important North American gas market dynamics that drive the longer-term pattern of the Algonquin and receipt-point price outlooks:

- Henry Hub and Dawn, Ontario prices remain higher than Leidy (Marcellus) prices. This reflects the low development and production costs of the highly-prolific new Marcellus shale gas play versus higher-cost, mature conventional gas producing regions that comprise much of the rest of North American gas supply;
- Henry Hub and Dawn prices show little seasonality. This is because gas is in demand for injection (April-October) at Dawn as well as at Henry Hub;

- Algonquin Citygate prices show strong seasonality. Little gas is needed in the summer and there is little storage capacity in New England, reducing prices substantially compared with the wintertime;
- Wintertime strength in Wright prices reflects the 100 percent utilization of Constitution pipeline in the winter;
- Mahwah prices do not spike in the winter after 2019, because as of that time the hub is unconstrained in the winter—it has enough capacity to supply points downstream;
- On an annual average basis, Northeast market area prices (Algonquin Citygate and Wright) are lower than Henry Hub towards the end of the forecast period, which means Algonquin basis to Henry Hub becomes negative.

The low-cost, prolific Marcellus shale gas has already allowed New England gas prices to fall below Henry Hub prices during the summer when gas demand in New England is low. Algonquin Citygate basis to Henry Hub registered a ***negative*** $0.58 per MMBtu (i.e., lower than Henry Hub) for April through October 2014. Basis from November 2014 through February 2015 averaged (positive) $6.57 per MMBtu.[11]

Figure 7. Monthly average gas prices at selected hubs, under the MECRA Baseline outlook



Source: History (through March 2015) and outlook GPCM MECRA Baseline outlook.

[11] Average gas prices from SNL, "Day-ahead Natural Gas prices - Monthly" data series.

Figure 8. Annual average gas prices for selected hubs, under the MECRA Baseline outlook (nominal $/MMBtu)

Year	Henry Hub	Algonquin Citygate	Wright	Mahwah	Dawn	Leidy	Niagara
2015	3.20	4.92	n/a	2.62	3.30	1.96	3.34
2016	3.56	4.18	2.34	2.59	3.64	2.01	3.66
2017	3.57	4.00	3.53	3.62	3.56	3.25	3.60
2018	3.76	4.06	3.83	3.82	3.70	3.48	3.75
2019	4.05	4.29	4.04	3.94	3.98	3.70	4.00
2020	4.32	4.50	4.21	4.08	4.21	3.82	4.19
2021	4.57	4.75	4.35	4.17	4.44	3.92	4.37
2022	4.87	5.15	4.56	4.29	4.72	4.03	4.61
2023	5.18	5.41	4.81	4.44	5.03	4.17	4.90
2024	5.43	5.44	4.98	4.53	5.28	4.26	5.14
2025	5.65	5.74	5.11	4.59	5.49	4.32	5.35
2026	5.91	5.84	5.27	4.68	5.76	4.40	5.61
2027	6.21	5.92	5.47	4.81	6.05	4.53	5.89
2028	6.43	5.99	5.62	4.92	6.25	4.62	6.08

Source: GPCM MECRA Baseline outlook. Note that Wright does not have a price until Constitution pipeline is added to the GPCM model.

3.2 MECRA Baseline outlook gas cost to Maine consumers

The price of gas at Algonquin multiplied by the level of consumption projected in the MECRA Baseline outlook provides the Baseline outlook "gas bill" to which the reductions generated by the ECRCs are compared.

LEI's estimates of gas consumption in Maine are based on the GPCM 4Q2014 data set (as detailed in Appendix B) with several adjustments. The residential consumption database provided by GPCM assumed no growth in residential gas demand for Maine after 2015; however, LEI projects this demand to grow at 1.5% per annum to reflect growth plans noted by Maine LDCs.[12] We also adjusted the GPCM industrial sector outlook to reflect the closure of three large pulp and paper mills in 2014 (this reduced industrial demand an estimated 11.7 MMcfd from 2015 onward); and we project flat demand after that. Commercial demand is based

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[12] Osborne, Gregory. President and CEO, Gas Natural Inc. (parent company of Bangor Gas), presentation at AGA Financial Forum, May 17-19, 2015; and Northern Utilities. *2001 Integrated Resource Plan 2011: 5-Year Natural Gas Portfolio Plan.* December 30, 2011.

on GPCM data, which incorporated a small amount of growth. As noted earlier, about 10.9 MMcfd of Maine LDC-served gas consumption is not exposed to changes to gas prices as it is served by a long-term contract. For ease of calculation and convenience, we attributed the 10.9 MMcfd of hedged consumption to the commercial sector. The cost benefit analysis will be based on impacts to Maine consumers as a whole, so it does not matter to the outcome where the hedged consumption is assigned. Thus, the cost of this quantity of gas is excluded here, because it will be excluded from our analysis of the benefits of the ECRCs. In summary, Figure 9 shows LEI's outlook for natural gas consumption in Maine, net of these adjustments.

Figure 9. Natural gas consumption by Maine residential, commercial, and industrial consumers, under the MECRA Baseline outlook (MMcfd)

	Residential	Commercial	Industrial	Total
2015	7.0	17.3	61.3	85.6
2016	7.1	18.6	61.3	86.9
2017	7.3	18.4	61.3	86.9
2018	7.4	19.7	61.3	88.3
2019	7.5	21.2	61.3	89.9
2020	7.6	21.4	61.3	90.2
2021	7.7	21.5	61.3	90.5
2022	7.8	21.7	61.3	90.8
2023	7.9	21.9	61.3	91.1
2024	8.0	22.1	61.3	91.4
2025	8.2	22.2	61.3	91.6
2026	8.3	22.4	61.3	92.0
2027	8.4	22.6	61.3	92.3
2028	8.5	22.8	61.3	92.6

Source: GPCM under the assumptions developed for the MECRA Baseline outlook with adjustments as noted in the text. Total may not equal sum of components owing to independent rounding.

The total gas bill is calculated as the Algonquin Citygate gas price multiplied by quantities consumed. This gas bill to Maine consumers is projected to decline with lower gas prices after AIM and Atlantic Bridge (non-ECRC) enter service in 2017. After 2018, rising prices and increasing consumption gradually increase the gas bill to Maine consumers (see Figure 10).

Figure 10. Wholesale cost of natural gas to Maine by customer class, under the MECRA Baseline outlook (million nominal dollars)

	Residential		Commercial		Industrial		Total	
2015	$	20	$	43	$	120	$	184
2016	$	17	$	38	$	101	$	156
2017	$	13	$	30	$	93	$	136
2018	$	12	$	32	$	94	$	138
2019	$	13	$	36	$	100	$	149
2020	$	14	$	38	$	105	$	157
2021	$	16	$	41	$	111	$	168
2022	$	18	$	46	$	121	$	184
2023	$	19	$	49	$	127	$	195
2024	$	19	$	49	$	127	$	196
2025	$	21	$	53	$	135	$	209
2026	$	22	$	54	$	137	$	213
2027	$	22	$	55	$	139	$	216
2028	$	23	$	56	$	140	$	219

Source: GPCM, under the assumptions developed for the MECRA Baseline outlook. Total may not equal sum of components owing to independent rounding.

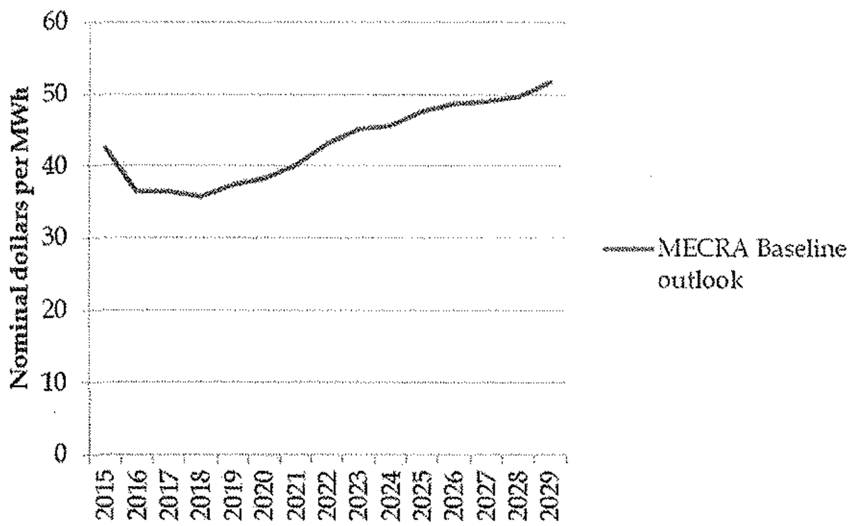
The wholesale gas price does not include the cost to deliver gas all the way to the customer's burnertip. The wholesale price is the price at the gas hub, in this case, the Algonquin Citygate price. In the gas industry, LDCs provide service from the main transmission pipelines to residential, commercial, industrial, and sometimes power plant users of gas. For the purposes of our analysis, however, we only want to establish a Baseline outlook against which to compare the impact of lower gas prices. Thus we assume that distribution costs of gas do not change across the cases, and they can be omitted from the analysis.

3.3 New England wholesale energy prices under the MECRA Baseline outlook

The outlook for wholesale energy prices is derived by using the gas price outputs of GPCM for Algonquin Citygate (the annual averages of which were shown in Figure 8) in LEI's simulation model, POOLMod. Details of POOLMod assumptions, structure, and data sources are provided in Appendix B to this report.

Lower gas prices for 2015 and 2016 (based on assumed normal weather) and for 2017 and later (reflecting the additions of TGP CT, AIM, and Atlantic Bridge non-ECRC) drive energy prices down in the early years of the Baseline outlook (see Figure 11). Potential increases in energy prices in 2020 and thereafter are mitigated by the assumed addition of imported energy from Quebec via new transmission.[13] More details of the drivers and assumptions of the Baseline energy outlook can be found in Appendix B. Over the longer term, rising energy prices reflect the rising cost of natural gas and the need for new plants to replace those that are scheduled to retire, as well as rising environmental compliance costs (see Appendix B for details of retirement and new entry assumptions).

Figure 11. Annual average wholesale energy price for Maine load zone, under the MECRA Baseline outlook (nominal $/MWh)



Source: POOLMod MECRA Baseline outlook.

LEI's projection of electricity consumed in Maine is provided by ISO-NE's CELT 2015 report (this same demand forecast is also used in the electricity market simulations). ISO-NE demand projections are net of demand response ("DR") and distributed photovoltaic solar generation ("PV"). The CELT report contains an outlook through 2024. LEI extrapolates from the CELT data, to project consumption from 2025 through 2028. ISO-NE expects Maine electricity consumption (net of DR and PV) to decline very slightly from 11.53 GWh in 2015 to 11.43 GWh in 2024 (retaining its 9% share of total New England electricity consumption); LEI expects a further small decline in Maine electricity consumption to 11.37 GWh in 2028, with 8.9% of total New England electricity consumption. The shares of consumption by sector (residential, commercial, industrial) are based on EIA historical data. In addition, for the purposes of

[13] Several power transmission lines are currently proposed, which would bring price-taking generation resources into New England from Quebec. For the purposes of representing such new supply resources, we modeled a generic 1,000 MW line that would start service in 2020.

calculating benefits to Maine consumers, LEI reduced electricity consumption each year by 4%, to account for the share of Maine load that is covered by long term retail hedges and thus is not exposed to wholesale market price changes over the forecast timeframe, as noted earlier (see Figure 12). The trend in Maine's electricity consumption is generally consistent with the trend for New England over all. Specifically, New England electricity consumption is projected to fall slightly from 128.2 GWh in 2015 to 127.5 GWh in 2028 in the MECRA Baseline outlook.

Figure 12. Maine electric power consumption by sector, under the MECRA Baseline outlook (GWh per annum)

	Residential	Commerical	Industrial	Total
2015	4.30	3.68	3.09	11.07
2016	4.31	3.69	3.10	11.09
2017	4.32	3.70	3.11	11.13
2018	4.35	3.72	3.13	11.20
2019	4.33	3.70	3.11	11.14
2020	4.30	3.68	3.09	11.08
2021	4.29	3.67	3.08	11.03
2022	4.27	3.66	3.07	11.00
2023	4.27	3.65	3.07	10.99
2024	4.26	3.65	3.06	10.98
2025	4.26	3.64	3.06	10.96
2026	4.25	3.64	3.06	10.94
2027	4.24	3.63	3.05	10.93
2028	4.24	3.63	3.05	10.91

Source: ISO-New England, adjusted for retail hedges as noted in the text. Total may not equal sum of components owing to independent rounding.

We calculate the wholesale energy component of the bill for Maine consumers as the average wholesale price of energy multiplied by annual consumption (net of the percentage of retail load hedged by long term contracts).[14] Assuming normal weather, the total power bill to Maine consumers is projected to rise from 2015 levels under the MECRA Baseline outlook (see Figure 13).

[14] This percentage (4%) was applied to the whole load, not allocated to only one sector.

Because consumption is projected to decline, the increase is strictly the result of rising power prices. As with gas prices, the wholesale energy price does not include other cost components to deliver power all the way to the customer, such as costs of transmission and distribution or the cost of capacity or ancillary services. For the purposes of our analysis, we only want to establish a Baseline outlook with which to compare the impact of lower gas prices on energy prices. Thus we assume that other costs of electricity that consumers pay do not change across the cases, and they can be omitted from the analysis. The cost of energy to Maine declines initially on lower gas prices, then increases following the trend in nominal gas prices (see Figure 13). As consumption is assumed to decline over the long term, higher total electricity costs are strictly driven by energy price increases.

Figure 13. Wholesale cost of energy by customer class, under the MECRA Baseline outlook (million nominal dollars)

	Residential	Commerical	Industrial	Total
2015	$ 183	$ 157	$ 132	$ 471
2016	$ 157	$ 134	$ 113	$ 404
2017	$ 157	$ 135	$ 113	$ 405
2018	$ 156	$ 133	$ 112	$ 401
2019	$ 162	$ 139	$ 117	$ 417
2020	$ 165	$ 141	$ 119	$ 425
2021	$ 172	$ 147	$ 124	$ 443
2022	$ 184	$ 158	$ 133	$ 475
2023	$ 192	$ 165	$ 138	$ 496
2024	$ 195	$ 166	$ 140	$ 501
2025	$ 203	$ 174	$ 146	$ 522
2026	$ 206	$ 177	$ 148	$ 532
2027	$ 208	$ 178	$ 149	$ 535
2028	$ 210	$ 180	$ 151	$ 542

Source: POOLMod, based on gas prices from GPCM and other assumptions from the MECRA Baseline outlook. Total may not equal sum of components owing to independent rounding.

4 Projection of benefits of ECRC proposals

As stated in the November 13th Order, the Commission's primary evaluation criteria are the net benefits to Maine gas and electricity ratepayers. Benefits include gas price benefits to Maine gas customers; energy market price benefits to Maine electricity customers, and any cost-mitigating impacts, for example, the market value associated with the resale of the contracted pipeline capacity (driven by incentives for arbitrage).

Thus the three sources of potential benefits of an ECRC that we include in our analysis are:

- lower gas prices in New England, which lead to lower gas bills compared to the Baseline outlook for Maine consumers in the residential, commercial, and industrial sectors;
- lower energy prices in New England, which lead to lower electricity bills compared to the Baseline outlook for Maine consumers; and
- the potential arbitrage value of the firm transportation rights conferred by the ECRCs.

We estimate benefits for gas and electricity customers separately, and then add them together. Benefits from potential resale of capacity are based on projections of Algonquin Citygate prices relative to the proposed receipt point prices in the ECRCs, and are also added into the total benefit metric. In our approach, we are not applying any specific weights to these three categories of benefits. Each category is treated equally in the total benefit metric, based on the merits of the associated dollar savings.

In total, nine different ECRC proposals were offered to Maine (see The size of each ECRC proposal modeled was based on either the size of the contract volume offered by the bidder (in the case of the Atlantic Bridge, Access Northeast, and TGP NED proposals), or the maximum implied size of the contract if FT were the only cost to Maine (for the C2C proposals). The C2C maximum size offered was 200,000 Dth/day, but given the proposed cost per Dth and the $75 million spending cap in the legislation, Maine could not contract for that full amount. So we modeled the volume that would be associated with the spending cap, namely [redacted] (C2C Dawn), [redacted] (C2C Niagara), and [redacted] Dth/day (C2C Wright).

Figure 14). However, we did not model the quantitative benefits of three of the proposals, for the following reasons:

- Atlantic Bridge, the "Brookfield to Beverly" route would likely have little price-reducing impact on Algonquin Citygate gas prices, because the receipt point (Brookfield) is not in a supply region, it is inside New England;
- Atlantic Bridge, the "Head of G to Beverly" route would likely have little price-reducing impact on Algonquin Citygate gas prices, because the receipt point (Beverly) is not in a supply region, it is inside New England;
- NED, the "Wright to downstream of Dracut" route would likely have a very similar impact on Algonquin prices and the as "Wright to Dracut" option, because the delivery points for Dracut and "downstream of Dracut" are both inside New England. The "downstream of Dracut" option is a higher-cost, lower-capacity option than the Dracut option. If Wright-to-Dracut does not create enough benefits to exceed its costs, then it is highly unlikely that the more-expensive and smaller option would do so, so we did not model it.

In the case of the two excluded Atlantic Bridge options, the benefits would not include impacts on Algonquin Citygate gas prices. In the NED case, the benefits would include impacts on Algonquin Citygate gas prices, but to a lesser degree than the NED Wright to Dracut proposal, so that there would be no need for separate modeling.[15] Therefore, for the purposes of examining the potential to reduce wholesale gas prices in New England (as represented by Algonquin Citygate prices), we modeled six ECRC proposals, as summarized in the figure below.

The size of each ECRC proposal modeled was based on either the size of the contract volume offered by the bidder (in the case of the Atlantic Bridge, Access Northeast, and TGP NED proposals), or the maximum implied size of the contract if FT were the only cost to Maine (for the C2C proposals). The C2C maximum size offered was 200,000 Dth/day, but given the proposed cost per Dth and the $75 million spending cap in the legislation, Maine could not contract for that full amount. So we modeled the volume that would be associated with the spending cap, namely [redacted] (C2C Dawn), [redacted] (C2C Niagara), and [redacted] Dth/day (C2C Wright).

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15 [redacted]

Figure 14. Routes, in-service dates, receipt and delivery points, and sizes of ECRCs modeled

Project	Route	Developer's in-service date (modeled)	Primary receipt point modeled	Primary delivery point modeled	FT cost (reservation rate) ($/Dth per day)	Total annual spending allowed by MECRA legislation	Maximum implied size of ECRC (if reservation rate is the only cost) in Dth	Size of ECRC modeled (Dth)
Atlantic Bridge	Mahwah-Beverly	Nov-17	Mahwah/Ramapo	Beverly	[redacted]	$75,000,000	[redacted]	[redacted]
~~Atlantic Bridge~~	~~Brookfield-Beverly~~	~~Nov-17~~	~~Brookfield~~	~~Beverly~~	[redacted]	[redacted]	[redacted]	[redacted]
~~Atlantic Bridge~~	~~Head of C-Beverly~~	~~Nov-17~~	~~sees GRCM base receipt point for this~~	~~Beverly~~	[redacted]	[redacted]	[redacted]	[redacted]
Access Northeast	Mahwah-Aggreg. Area	Nov-18	Mahwah/Ramapo	Beverly	[redacted]	$75,000,000	[redacted]	[redacted]
Continent to Coast	Dawn-Maine (Dracut)	Nov-17	Dawn	Dracut	[redacted]	$75,000,000	[redacted]	[redacted]
Continent to Coast	Niagara-Maine (Dracut)	Nov-17	Niagara/Chippawa	Dracut	[redacted]	$75,000,000	[redacted]	[redacted]
Continent to Coast	Wright-Maine (Dracut)	Nov-17	Wright	Dracut	[redacted]	$75,000,000	[redacted]	[redacted]
Northeast Energy Direct	Wright-Dracut	Nov-18	Wright	Dracut	[redacted]	$75,000,000	[redacted]	[redacted]
~~Northeast Energy Direct~~	~~Wright-downstream of Dracut~~	~~Nov-18~~	~~Wright~~	~~Beverly~~	[redacted]	[redacted]	[redacted]	[redacted]

Sources:

Atlantic Bridge: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit E "Non-binding Term Sheet Atlantic Bridge Firm Transportation Service;" "Rate Schedule AFT-1 Firm Transportation Service;" and conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

Access Northeast: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit A "Rate Schedule ERS Electric Reliability Service;" Exhibit B "Non-binding Term Sheet Access Northeast Project-Electric Reliability Service;" and conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

C2C: MPUC Docket No. 2014-00071, File No. 213: PNGTS. "ECRC Proposal December 5, 2014, PNGTS C2C Project;" conference call/meeting with PNGTS, LEI, Commission staff, February 5, 2015.

NED: MPUC Docket No. 2014-00071, File No. 212: TGP. "ECRC Proposal of Tennessee Gas Pipeline Company LLC," December 4, 2014; Attachment A-2 "Precedent Agreement;" Attachment 2 "Overview of the Offer;" File No. 263. Appendix B to "Negotiated Rate Agreement."

4.1 The ECRCs individually reduce New England gas prices, but not dramatically

Each of the ECRC proposals on its own has a noticeable but not game-changing effect on Algonquin Citygate gas prices (see Figure 15). The difference from one project versus another is fairly small, because the ECRCs are of a similar size – the project sizes range from 80,000 Dth/day [redacted] to 166,000 Dth/day [redacted]. Differences in receipt point prices have a small impact on Algonquin Citygate prices. Mahwah gas is projected to be cheaper than Wright (as seen in Figure 7 previously). This difference results in slightly lower Algonquin Citygate prices (on an annual average basis) in the case of Atlantic Bridge compared to NED.

Figure 15. Annual average Algonquin Citygate gas prices, under the MECRA Baseline outlook and ECRCs (nominal $/MMBtu)

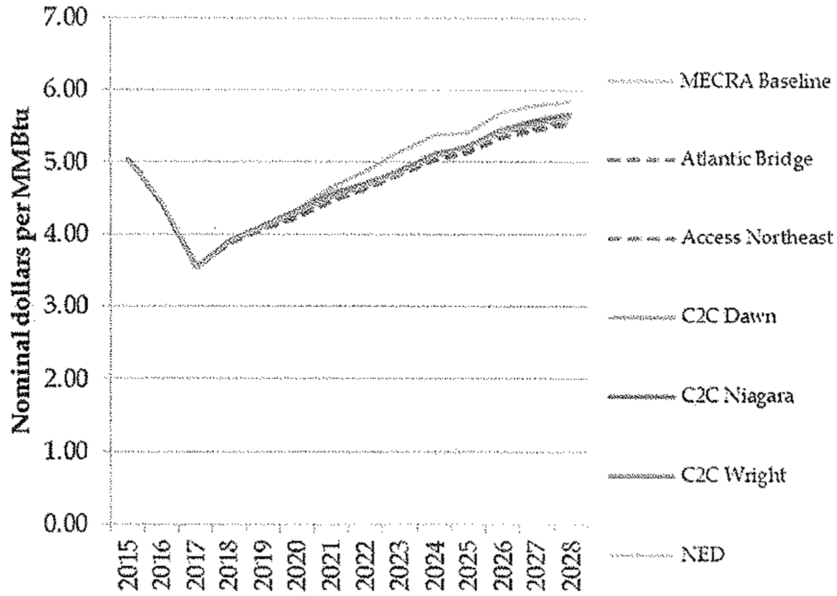


Figure 16, Figure 17, and Figure 18 show the outlook for monthly gas prices. Notably, there is no effect on summertime gas prices relative to the MECRA Baseline outlook, as ECRC capacity is not needed in the summer. However, wintertime price increases do not disappear. This implies there will be some arbitrage (re-sale) value to FT even after one of the ECRCs is completed.

Figure 16. Monthly average Algonquin Citygate gas prices, under the MECRA Baseline outlook and with NED or C2C Wright

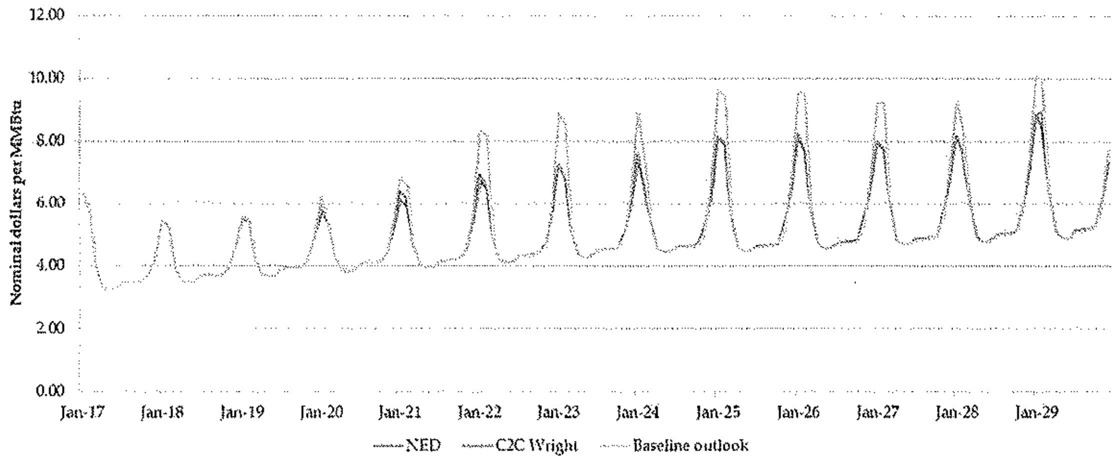


Figure 17. Monthly average Algonquin Citygate gas prices, under the MECRA Baseline outlook and with C2C Niagara or C2C Dawn

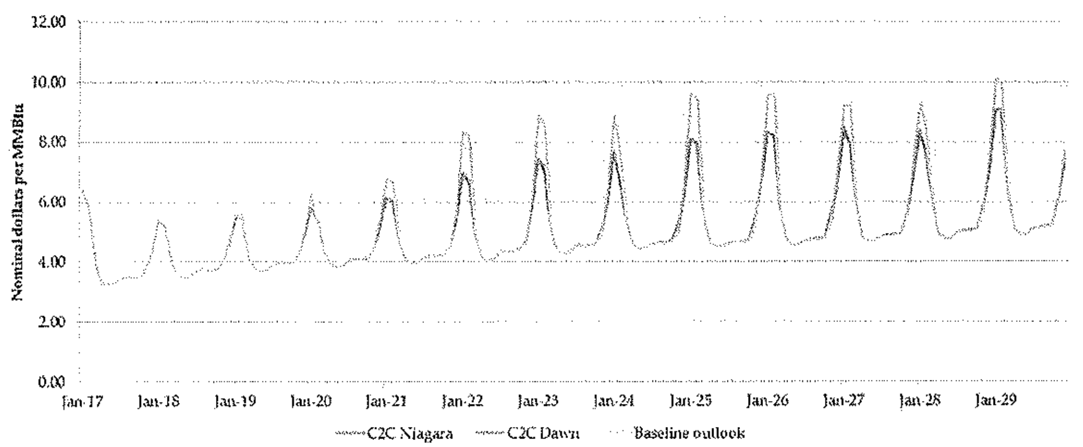
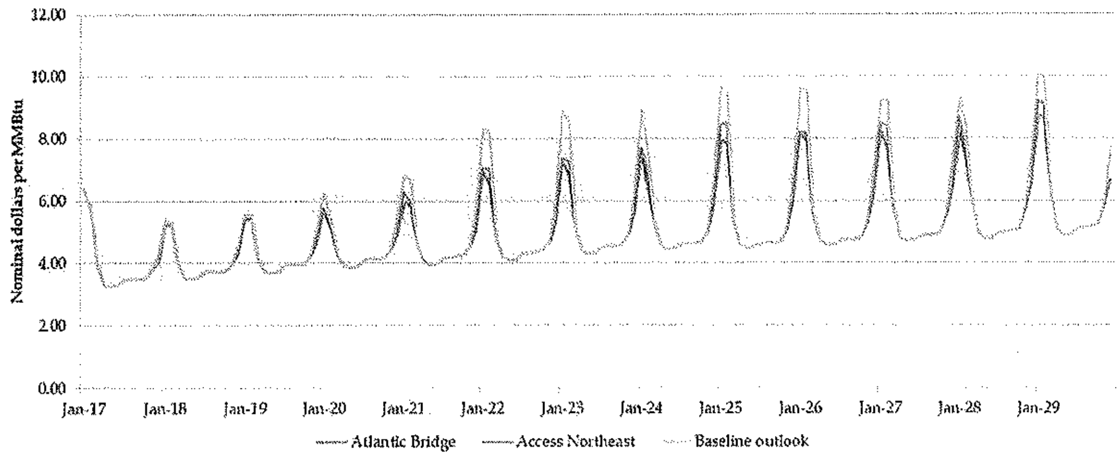


Figure 18. Monthly average Algonquin Citygate gas prices, under the MECRA Baseline outlook and with Atlantic Bridge or Access Northeast



The analysis examines the impact of each ECRC individually, so it implicitly assumes only one project will be completed, relative to the Baseline outlook.

TGP/KM has reported publicly that the NED market path project (Wright to Dracut) already has 500,000 Dth of firm commitments. In spite of this, we did not include it in the Baseline outlook, because TGP/KM also noted in confidential materials that [redacted] [17] The ECRC on offer to Maine is [redacted]. To provide the Commission with insight into the impacts of potentially choosing the NED ECRC, LEI also modeled a variant of NED at [redacted] [redacted] (which we refer to as "NED A").

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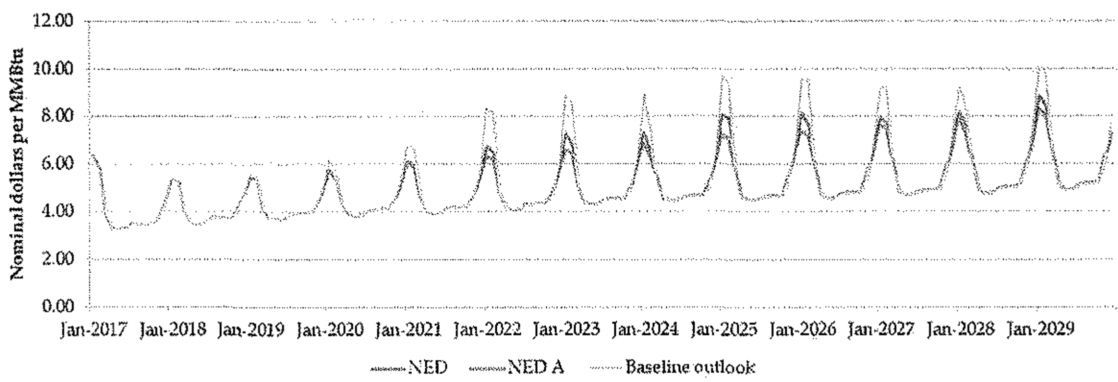
[16] TGP. Conference call with TGP, LEI, Commission staff. February 5, 2015; and Tennessee Gas Pipeline. MPUC Docket No. 2014-00071. File No. 263. Attachment A-2 "Precedent Agreement."

[17] TGP. Conference call with TGP, LEI, Commission staff. February 5, 2015; and Tennessee Gas Pipeline. MPUC Docket No. 2014-00071. File No. 263. Attachment A-2 "Precedent Agreement."

4.2 NED A case reduces gas prices a little bit more

There is a noticeable reduction in gas prices from NED A, compared with the NED ECRC at [redacted] (see Figure 19). This is not surprising, as NED A is a larger project and should be expected to reduce gas prices more. We therefore included the NED A case in the cost benefit analysis for comparison purposes.

Figure 19. Monthly average Algonquin Citygate gas prices under the MECRA Baseline outlook, and with NED (at [redacted]) or, NED A

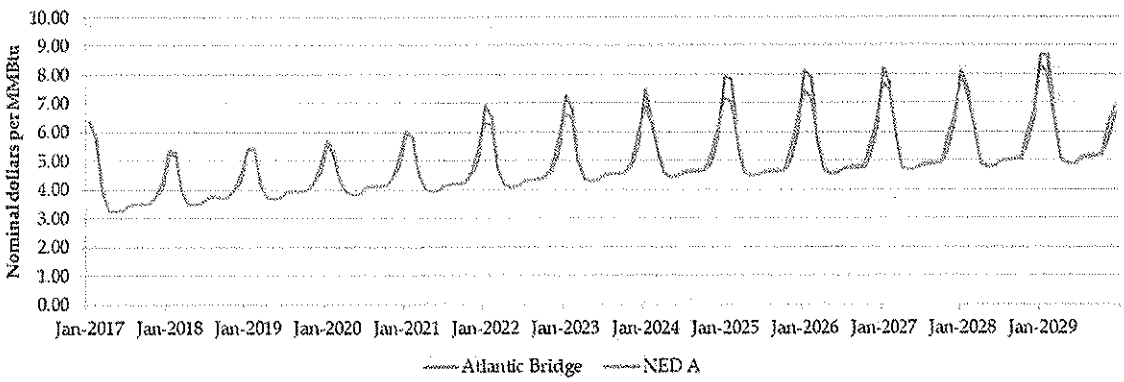


In summary, the annual price reductions from NED A and Atlantic Bridge are the largest, and are within pennies of one another (see Figure 20); NED A prices are somewhat lower during the winter, beginning in 2022 (see Figure 21). That is because NED A is larger than Atlantic Bridge, and by 2022, the size difference will help gas supply keep up with demand growth.

Figure 20. Tabular summary of projected annual average Algonquin Citygate gas prices, under the MECRA Baseline outlook and under each of the ECRCs (nominal $/MMBtu)

	Atlantic Bridge	Access Northeast	C2C Dawn	C2C Niagara	C2C Wright	NED	NED A	MECRA Baseline
2015	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03
2016	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42
2017	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53
2018	3.88	3.91	3.91	3.91	3.92	3.91	3.91	3.91
2019	4.08	4.09	4.11	4.11	4.13	4.11	4.10	4.13
2020	4.24	4.27	4.31	4.31	4.34	4.30	4.28	4.35
2021	4.46	4.50	4.52	4.51	4.58	4.52	4.49	4.65
2022	4.64	4.66	4.69	4.69	4.72	4.67	4.62	4.88
2023	4.83	4.88	4.90	4.89	4.89	4.86	4.80	5.15
2024	5.04	5.09	5.14	5.12	5.10	5.10	5.01	5.38
2025	5.13	5.19	5.22	5.22	5.23	5.20	5.14	5.41
2026	5.35	5.45	5.42	5.45	5.46	5.44	5.29	5.70
2027	5.44	5.48	5.57	5.60	5.55	5.53	5.43	5.79
2028	5.54	5.64	5.65	5.67	5.63	5.63	5.58	5.85

Figure 21. Monthly average Algonquin Citygate gas prices under Atlantic Bridge ECRC and [redacted] (nominal $/MMBtu)



4.3 Benefits to Maine gas consumers

The benefits of an ECRC to gas consumers in Maine are reflected in the reduction in the total cost of gas. We include these cost reductions for 10 years for each project, as directed in the November 30th Order. Access Northeast and NED are assumed to have an in-service date of November 2018 (according to the proposals submitted by each bidder), so we include the benefits through 2028; the other projects are assumed to come into service November 2017 (according to each project's respective bidder), so we include the benefits through 2027. Most of the benefits of any ECRC are accrued in January and February because gas prices are highest then under weather normalized conditions, so we include an "extra" year to capture the January and February benefits in the tenth year of service. In every case, we assumed the same level of gas consumption as in the MECRA Baseline outlook. Thus the benefits to consumers are strictly the result of lower gas prices. In the benefits analysis, we include impacts on residential, commercial and industrial customers, but we exclude the impact on power consumers. The impact on power plants will be reflected in the price of energy, so we omit those consumers from the gas benefit calculus, to avoid double-counting.

All the costs and benefits are discounted to 2015 dollars. We use a discount rate of 9%, which is in line with pre-tax weighed average costs of capital (WACC) used in recent MPUC rate cases, which ranged from 7.49%-11.75%.[18]

The net present value of reductions in wholesale gas costs range from a total NPV of $30 million for C2C Wright to $50 million for NED A (see Figure 22). As noted earlier, NED A and Atlantic Bridge both reduced annual average gas prices by similar amounts, but slightly lower winter prices under NED A result in slightly higher benefits for NED A.

[18] Maine Public Utility Commission Docket numbers 2013-00443; 2014-00118; 2014-00168; and 2014-00113.

Figure 22. Maine retail gas bill savings (residential, commercial, industrial) relative to baseline (million 2015 dollars, 9% discount rate)

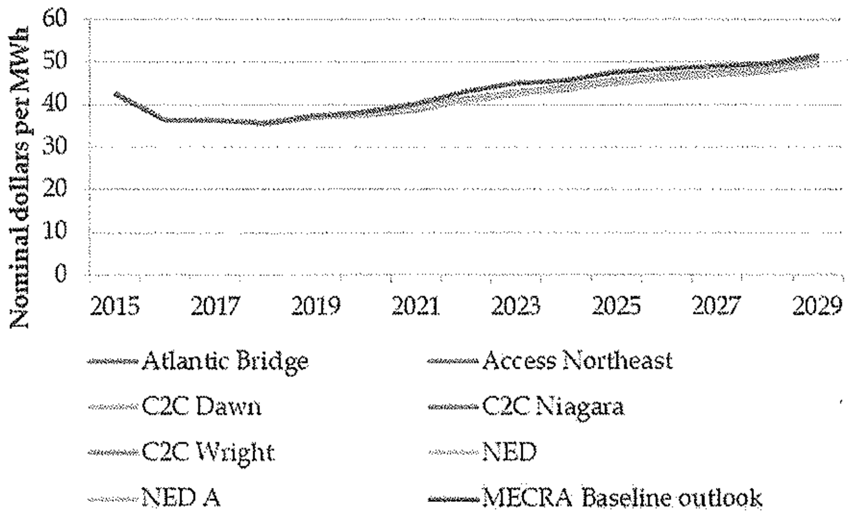
	Atlantic Bridge	Access Northeast	C2C Dawn	C2C Niagara	C2C Wright	NED	NED A
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.7	0.0	0.0	0.0	0.0	0.0	0.0
2018	1.8	0.8	0.3	0.2	-0.2	0.0	0.0
2019	2.7	2.2	0.9	0.8	0.0	0.9	1.7
2020	5.9	4.6	2.9	3.1	0.7	3.0	3.7
2021	8.8	6.9	5.7	5.6	3.4	5.8	7.0
2022	14.5	12.0	11.2	11.7	11.8	13.1	15.9
2023	15.6	13.4	11.8	12.4	13.2	13.4	17.3
2024	13.2	10.4	9.3	8.8	8.5	10.1	13.0
2025	16.8	12.0	12.0	11.2	11.5	11.9	18.7
2026	16.0	14.4	11.2	9.9	12.1	12.8	17.8
2027	14.2	10.0	8.8	9.6	10.9	11.6	13.7
2028		9.5				8.6	11.1
NPV 9%	48.7	41.0	32.0	31.9	30.0	38.0	50.0

Note: Annual gas costs reflect a sum of demand-weighted monthly costs whereby gas demand each month is multiplied by the monthly gas price. This allows the benefits calculations to reflect the greater use of gas during the winter when prices are higher. For one project in one year (2018), estimated cost reductions are slightly negative (i.e., ECRC costs are higher than the MECRA Baseline outlook). This results from GPCM projections of gas prices at the 3rd or higher decimal place that are higher than MECRA Baseline gas prices. The small difference results from the timing of the ECRC expansion compared to nearby pipeline expansions, and the price impacts are too small to affect gas prices rounded to the nearest cent per MMBtu.

4.4 Lower energy prices and benefits to Maine electricity consumers

As a result of the downward impact on delivered gas prices in New England, each ECRC also reduces wholesale energy prices in New England, including in the Maine load zone. On an annual basis, the wholesale energy price reductions compared to the baseline are fairly small, reflecting small reductions in annual average gas prices (see Figure 23 and Figure 24).

Figure 23. Maine load zone wholesale energy price under the MECRA Baseline Outlook and under each modeled ECRC proposal



Source: History; ISO-NE; outlook LEI's Poolmod. Note: These are demand-weighted average energy prices.

Figure 24. Difference in annual average wholesale energy prices for Maine load zone under each ECRC proposal compared to the MECRA Baseline outlook (nominal dollars per MWh)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Atlantic Bridge	0.00	-0.14	-0.31	-0.50	-1.00	-1.43	-2.26	-2.49	-2.17	-2.60	-2.57	-2.22	-2.08	-2.44
Access Northeast	0.00	0.00	-0.14	-0.37	-0.78	-1.12	-1.88	-2.16	-1.75	-1.86	-2.33	-1.58	-1.54	-1.81
C2C Dawn	0.00	0.00	-0.04	-0.15	-0.49	-0.92	-1.71	-1.89	-1.53	-1.79	-1.79	-1.32	-1.21	-1.32
C2C Niagara	0.00	0.00	-0.03	-0.12	-0.55	-0.90	-1.81	-1.98	-1.41	-1.62	-1.50	-1.44	-1.30	-1.23
C2C Wright	0.00	0.00	0.02	0.02	-0.12	-0.51	-1.79	-2.07	-1.30	-1.68	-1.83	-1.60	-1.35	-1.57
NED	0.00	0.00	0.00	-0.14	-0.50	-0.93	-2.06	-2.10	-1.61	-1.73	-1.90	-1.70	-1.32	-1.73
NED A	0.00	0.00	0.00	-0.33	-0.63	-1.13	-2.47	-2.71	-2.05	-2.77	-2.67	-2.02	-1.68	-2.37

Note: negative sign implies a price reduction from the energy price levels under the MECRA Baseline outlook.

The benefits of an ECRC to electricity consumers in Maine are reflected in the reduction in the total cost of energy. This affects all but the 4% of retail customers in Maine who are served by long-term contract, as noted earlier. As in the gas savings analysis, the NPV of each project was evaluated within its own timeframe (i.e., Atlantic Bridge from 2017-2027; NED from 2018-2028), and then discounted to a common start year of 2015. For this analysis we include the entire 11th year of power bill savings, to make the time frame of the analysis consistent with the time period covered in the estimation of benefits to gas consumers. In every ECRC project case, we assumed the same level of annual energy consumption as in the MECRA Baseline outlook. Thus, the difference in cost reductions to electricity consumers across the modeled ECRC projects is strictly owing to the difference in wholesale energy prices.

Reductions in wholesale energy costs to Maine consumers through 2028 range from $49.9 million for C2C Wright to $86.5 million for Atlantic Bridge (see Figure 25).

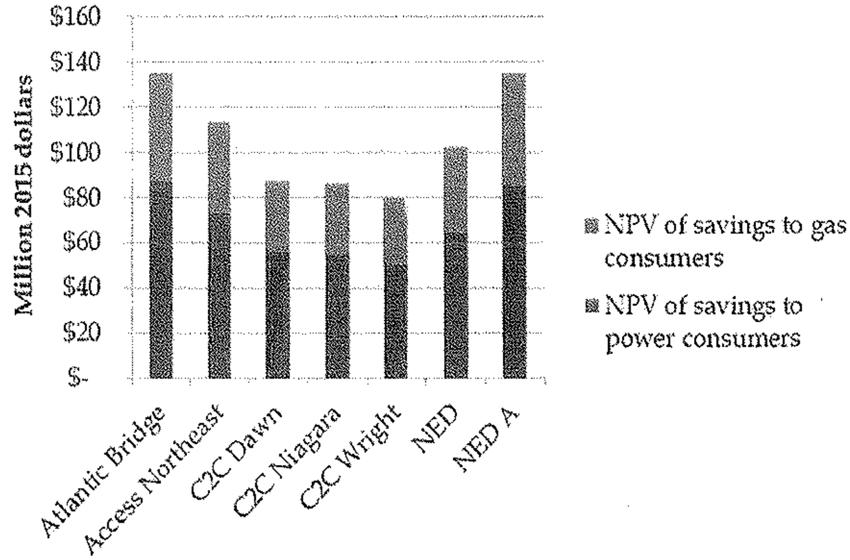
Figure 25. Maine retail power bill savings relative to MECRA Baseline outlook (million 2015 dollars, 9% discount rate)

	Atlantic Bridge	Access Northeast	C2C Dawn	C2C Niagara	C2C Wright	NED	NED A
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	1.5	0.0	0.0	0.0	0.0	0.0	0.0
2018	3.5	1.6	0.5	0.4	-0.3	0.0	0.0
2019	5.5	4.1	1.6	1.4	-0.2	1.5	3.7
2020	11.0	8.6	5.4	6.1	1.3	5.5	7.0
2021	15.8	12.3	10.2	9.9	5.7	10.3	12.4
2022	24.9	20.6	18.8	19.9	19.7	22.7	27.1
2023	27.4	23.7	20.8	21.8	22.7	23.0	29.8
2024	23.8	19.2	16.8	15.5	14.3	17.6	22.5
2025	28.4	20.4	19.6	17.8	18.4	18.9	30.3
2026	28.1	25.5	19.6	16.5	20.0	20.8	29.2
2027	24.3	17.3	14.5	15.7	17.5	18.6	22.1
2028		16.8				14.4	18.4
NPV 9%	86.5	72.7	55.5	54.6	49.9	64.4	85.1

In one case, in 2018 and 2019, estimated cost reductions are slightly negative (i.e., ECRC costs are higher than the Baseline outlook). This results from GPCM projections of gas prices at the 3rd or higher decimal place that are higher than Baseline gas prices. The small difference results from the timing of the ECRC expansion compared to nearby pipeline expansions, with price impacts that are too small to affect gas prices rounded to the nearest cent per MMBtu.

Figure 26 shows the combined results for savings to gas and electricity customers. This summation makes it evident that projects that have larger reductions in gas costs to Maine consumers also have larger reductions in energy costs to Maine consumers. This is because lower gas prices lead to lower electric energy prices, as gas is on the margin for electricity production most of the time in New England.

Figure 26. Net present value of ten years of reductions in gas and energy costs to Maine consumers from each ECRC evaluated (million 2015 dollars, 9% discount rate)



4.5 Estimating the resale value of FT contracts

As directed in the November 13th Order, benefits of an ECRC for FT should include any cost-mitigating impacts, for example, the offset associated with the market value of any resale of capacity. The price difference between the receipt point and the delivery point of an FT contract provides the foundation for estimating the expected market value of resale capacity. A potential buyer of FT on a given route will benefit more from larger price differences on the route. In New England, as we saw previously, gas prices at Algonquin Citygate are much higher (in the winter) than prices at the ECRC receipt points (Dawn, Niagara, Wright, Mahwah). Thus a holder of FT can buy gas in the winter at receipt point prices and sell it at Algonquin Citygate prices, and earn the difference. A buyer would presumably pay a price up to the value of the difference (less variable transport costs) to own the FT rights. This resale price represents a benefit to Maine consumers, if Maine owned the FT rights.

To estimate the potential size of this resale benefit, we assume that Maine releases FT rights in the full amount of the ECRC from December 1 through February 28 each winter. This 90-day period is the time in which Algonquin Citygate prices are highest, so it provides the strongest incentive for potential buyers of this capacity, and the highest potential resale value of this capacity (on a monthly basis). During the other months, basis is either negative, zero or very slightly positive. Therefore, for each ECRC, LEI calculated the difference between the gas price at Algonquin Citygate and the gas price at the receipt point from December 1-February 28 (we used 90-day averages). We assume this difference is the maximum price a buyer would pay for FT. We further assume that 100% of FT is re-sold at the maximum price a buyer would be willing to pay, which makes the ECRCs appear in the most favorable light with respect to this benefit (i.e., we are valuing the resale value based on the highest prices possible given the forecasts). The projected market value from capacity resale are shown in Figure 27

Figure 27. Net present value of the projected resale value of ECRC (million 2015 dollars, 9% discount rate)

ECRC	Potential resale value of FT
Atlantic Bridge	[redacted]
Access Northeast	
C2C Dawn	
C2C Niagara	
C2C Wright	
NED	
NED A	

The project with the largest resale value is C2C Niagara. Its downward impact on Algonquin Citygate price is small, while its receipt point gas price is lower than C2C Dawn (the second-highest). NED A has the lowest resale value because the larger size of the pipeline (at [redacted] Dth/day) reduces Algonquin Citygate winter prices more than the other projects, and the portion of the FT that Maine would own and be able to re-sell would still be only the [redacted] Dth/day under the proposed ECRC.

When the three sources of ECRC benefits are totaled, C2C Niagara is in first place, but the differences between it and the second-place Atlantic Bridge is small (see Figure 28 and Figure 29). The resale value of the C2C Niagara project works in its favor—the project has little impact on gas prices; but because of that, it retains its resale value. C2C Wright is in last place—it has about the same impact on gas and power bills as the other C2C projects, but its resale value is lower because average Wright prices are slightly higher in the winter (the 90-day period we examined) than Dawn or Niagara.

4.6 Why resale value weighs so heavily in total benefits

As noted earlier, Maine consumes only about 7% of the gas in New England and only 9% of the power. Thus it only benefits from a small share of the impact of lower gas prices and lower power prices on New England consumers. However, as owner of FT rights, Maine earns 100% of the resale value of an ECRC. Thus, FT on a pipeline that only has a small impact on gas prices can be more valuable than the savings to gas and power consumers, for a small consumer such as Maine.

Figure 28. Projected total benefits of each ECRC proposal as mandated by Commission's November 13th Order (million 2015 dollars, 9% discount rate)

Redacted

Figure 29. Table of projected total benefits of each ECRC proposal (million 2015 dollars, 9% discount rate)

ECRC	Potential resale value	Reduction in retail gas costs	Reduction in retail energy costs	Total benefits
Atlantic Bridge	[redacted]	$ 49	$ 87	[redacted]
Access Northeast	[redacted]	$ 41	$ 73	[redacted]
C2C Dawn	[redacted]	$ 32	$ 56	[redacted]
C2C Niagara	[redacted]	$ 32	$ 55	[redacted]
C2C Wright	[redacted]	$ 30	$ 50	[redacted]
NED	[redacted]	$ 38	$ 64	[redacted]
NED A	[redacted]	$ 50	$ 85	[redacted]

The ECRCs provide several other benefits in addition to FT rights that could be attractive to buyers. For example, the NED Wight-to-"downstream of Dracut" route offers delivery to a variety of points which might be constrained (for an additional reservation charge). Access Northeast has a component that offers no-notice delivery supported by LNG storage, to help address "last-mile" deliverability. The value of these features would depend on the particular location and needs of the potential buyer, and thus are difficult to estimate. More detail of these and other characteristics of the ECRCs can be found in Appendix A.

5 Analysis of costs and calculation of net benefits of ECRC proposals

Pursuant to the November 13th Order, the Commission requires any ECRC to produce net benefits, based on comparing the net present value of the first ten years of expected benefits with the net present value of the entire cost obligation. This reflects the greater risk and uncertainty in benefits as compared to costs. LEI therefore included only the first ten years of benefits in our calculations above.

LEI calculated the cost of each ECRC as the reservation rate multiplied by the size of the contract and the contract term. This amounts to the fixed costs of an ECRC. The annual values were discounted back to 2015 dollar terms using a 9% discount rate, consistent with the discounting of the benefits. We excluded any variable costs such as the fuel surcharge, as it would be borne by the actual eventual shipper, not the State of Maine. LEI calculated costs for the same subset of ECRCs for which we projected benefits. The costs range from about $254 million for Access Northeast (the lowest cost because it is the smallest contract size) to $509 million for the C2C proposals. The total cost for the C2C proposals is similar, because the bidder offered an ECRC size that, combined with the FT reservation rate, exceeded the $75 million per year cap established by the MECRA legislation. So, for purposes of the analysis we assumed a contract size for the C2C proposals that kept the total cost within the legislated annual spending limit.

Figure 30. Cost of selected ECRC proposals, NPV (million 2015 dollars, 9% discount rate)

Contract element	Atlantic Bridge	Access Northeast	C2C Dawn	C2C Niagara	C2C Wright	NED
Reservation rate $/Dth)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Size (Dth)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Term (years)	15	[redacted]	15	15	15	[redacted]
NPV of contract cost, 9% discount rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sources:

Atlantic Bridge: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit E "Non-binding Term Sheet Atlantic Bridge Firm Transportation Service;" "Rate Schedule AFT-1 Firm Transportation Service;" and conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

Access Northeast: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit A "Rate Schedule ERS Electric Reliability Service;" Exhibit B "Non-binding Term Sheet Access Northeast Project-Electric Reliability Service;" and conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

C2C: MPUC Docket No. 2014-00071, File No. 213: PNGTS. "ECRC Proposal December 5, 2014, PNGTS C2C Project;" conference call/meeting with PNGTS, LEI, Commission staff, February 5, 2015.

NED: MPUC Docket No. 2014-00071, File No. 212: TGP. "ECRC Proposal of Tennessee Gas Pipeline Company LLC," December 4, 2014; Attachment A-2 "Precedent Agreement;" Attachment 2 "Overview of the Offer;" File No. 263. Appendix B to "Negotiated Rate Agreement."

The following table (Figure 31) summarizes the results of the previous benefits analysis, and nets the total benefits against the costs. In every case, the cost of the ECRC exceeds the benefits. There is no ECRC with positive net benefits.

Figure 31. Costs and benefits of ECRCs on a NPV basis (million 2015 dollars, 9% discount rate)

ECRC	Potential resale value	Reduction in retail gas costs	Reduction in retail energy costs	Total benefits	Reservation cost of ECRC	Net benefits
Atlantic Bridge	[redacted]	$ 49	$ 87	[redacted]	[redacted]	[redacted]
Access Northeast	[redacted]	$ 41	$ 73	[redacted]	[redacted]	[redacted]
C2C Dawn	[redacted]	$ 32	$ 56	[redacted]	[redacted]	[redacted]
C2C Niagara	[redacted]	$ 32	$ 55	[redacted]	[redacted]	[redacted]
C2C Wright	[redacted]	$ 30	$ 50	[redacted]	[redacted]	[redacted]
NED	[redacted]	$ 38	$ 64	[redacted]	[redacted]	[redacted]
NED A	[redacted]	$ 50	$ 85	[redacted]	[redacted]	[redacted]

These results do not imply that the projects that underpin the ECRCs are necessarily uneconomic. Indeed, several of these projects have already contracted with private sector shippers such as LDCs and have firm commitments. Therefore, LEI's analysis should not be interpreted to mean these parties made poor business decisions. LCDs do not rely on reductions in gas basis differentials or lower power prices to justify the cost of FT; the FT cost is a component of service reliability, and is recovered in the LDC's rates.

5.1 Implications: Level of consumption drives net benefits

The results of LEI's analysis—that the benefits the ECRCs to Maine consumers are too small to exceed costs to Maine—are driven by the relatively low level of gas and power consumed in Maine as compared to the New England region. As noted earlier, Maine accounts for only about 7 % of the gas consumed in New England, and about 9% of the regional electricity consumption. In a larger state, such as Massachusetts, the consumption of gas for residential, commercial, and industrial use (at about 800 MMcfd in 2014) is about 7 times that of Maine. Electricity consumption in Massachusetts (at about 59 GWh in 2014) is 5 times that of Maine. So the impact of lower gas prices of any of the ECRCs would likely also be 7 times greater, and the impact of lower energy prices would also be 5 times that seen in Maine (under the presumption of no congestion in the ISO-NE transmission grid and no retail hedges). With these greater benefits to gas and power consumers, all the ECRC proposals could show benefits greater than their costs, even if Massachusetts paid all the costs. This is not to suggest that Massachusetts should make a

6.1 Type of product offered

The type of product provided by the ECRCs includes attributes such as the type of service offered, the volume of capacity on offer for ECRC or options for volumes of capacity, term of ECRC (number of years), and the terms of assignment of the contract to potential replacement shippers.

6.1.1 Conventional rateable FT versus ERS

The type of service offered by three of the four ECRCs is firm transportation service (see Figure 33). It is "rateable" service, which means it is based on a maximum daily transportation quantity ("MDTQ") which is to be delivered at an hourly rate of 1/24 of the scheduled daily quantity. Rateable service is a typical arrangement with shippers (pipeline customers). In practice, pipelines try to accommodate fluctuations in a shipper's hourly needs, but under rateable tariffs they are not required to do so. FT service has the highest priority on the pipeline. Customers holding FT contracts pay a monthly reservation (demand) charge to reserve space in the pipeline, regardless of whether they use the space during the month.

The type of service offered by Access Northeast (dubbed Energy Reliability Service ("ERS")) is somewhat different. It is FT service but it also includes firm "no-notice" service with non-rateable delivery rights. It allows the shipper to nominate volumes with 2-hours' notice in excess of the shipper's MDTQ. This flexibility is supported by a contract for firm capacity in LNG storage that is included in the FT rate.[19] Access Northeast proposes to provide the capacity for LNG delivery of about [redacted].[20] This is intended to help meet gas demand by power producers on peak hours of peak days. This is similar to the strategy used by LDCs to meet demand surges during peak hours of the winter. For example, Northern Utilities' Integrated Resource Plan ("IRP") notes that an important part of Northern's resource portfolio is an on-system LNG facility that can produce 10,000 Dth per day (about 10% of the maximum daily quantity Northern must supply). Northern reports that this is used as peaking supply for winter's coldest days, to get through morning demand for gas, and to meet demand on Monday mornings that are colder than originally forecasted on Friday when weekend gas was procured.[21] These are the same occasional conditions under which many power producers would also tend to need extra gas. Access Northeast is focused on specifically identified delivery points ("producer aggregation areas") where laterals are to be expanded as part of the ERS to facilitate use of LNG.

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[19] Spectra. MPUC Docket No 2014-00071, File No. 215: "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. December 5, 2014; Exhibit A "Rate Schedule ERS Electric Reliability Service;" and Conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

[20] Spectra. Conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

[21] Northern Utilities, Inc. *2011 Integrated Resource Plan: 5-Year Natural Gas Portfolio Plan*. December 30, 2011.

Figure 33. Type of product offered

Bidder	Spectra Energy	Spectra Energy	PNGTS	TGP/KM
Project name	Atlantic Bridge	Access Northeast	Continent to Coast	Northeast Energy Direct
Type of service	FT, rateable	FT, no-notice, non-rateable (supported by LNG storage)	FT, rateable	FT, rateable
Volume on offer in ECRC	[redacted]	Up to 80 MMcfd	Up to 200 MMcfd	[redacted]
Length of contract term	15 (Algonquin); 2 (M&NP)	[redacted]	15	[redacted]
MFN (most-favored nation) rate?	[redacted]	[redacted]	[redacted]	[redacted]
Assigment of contract, replacement shippers	[redacted]	Electric generators/electric distribution companies (who will need approval of state PUCs)	[redacted]	[redacted]

Sources:

Atlantic Bridge: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit E "Non-binding Term Sheet Atlantic Bridge Firm Transportation Service;" "Rate Schedule AFT-1 Firm Transportation Service;" and conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

Access Northeast: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit A "Rate Schedule ERS Electric Reliability Service;" Exhibit B "Non-binding Term Sheet Access Northeast Project-Electric Reliability Service;" and conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

C2C: MPUC Docket No. 2014-00071, File No. 213: PNGTS. "ECRC Proposal December 5, 2014, PNGTS C2C Project;" conference call/meeting with PNGTS, LEI, Commission staff, February 5, 2015.

NED: MPUC Docket No. 2014-00071, File No. 212: TGP. "ECRC Proposal of Tennessee Gas Pipeline Company LLC," December 4, 2014; Attachment A-2 "Precedent Agreement;" Attachment 2 "Overview of the Offer;" File No. 263. Appendix B to "Negotiated Rate Agreement."

6.1.2 Volumes

The volumes offered generally reflect the maximum budget outlined in the MECRA legislation. That maximum is 200 MMcfd, or a total amount that does not exceed $75 million per year.[22] All the ECRC proposals allow flexibility in the size of the contract, as no minimum quantities are required.

TGP is offering the quantity of [redacted] on NED.[23] These are not minimum requirements.[24] [redacted].[25] [redacted].[26]

6.1.3 Fuel Reimbursement

Scheduling and delivery of gas under typical FT contracts also includes a "Fuel Reimbursement Quantity." A small amount of gas is consumed as fuel in the transportation process. Delivery of gas is equal to the daily quantity scheduled, less the Fuel Reimbursement Quantity. This holds for all the ECRC proposals. Fuel reimbursement percentages typically range from 1%-4% depending receipt and delivery points, and are specified in pipeline tariffs.

6.1.4 Term of contract

The length of contract term offered for the projects, at 15-20 years, is typical for the industry. [redacted] The term of the M&NP portion of the Atlantic Bridge project is two years.

6.1.5 Assignment

The flexibility for assignment of the contract varies somewhat across the proposals. The pipelines generally must approve the assignment of a contract or a replacement customer/shipper and have standards such as creditworthiness that they apply.

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[22] State of Maine. *Maine Energy Cost Reduction Act* in 35-A M.R.S.§1904(2). 2013.

[23] TGP. MPUC Docket No. 2014-00071. File No. 212. Attachment 2 "Overview of the Offer;" and File No. 263. Attachment A-2 "Precedent Agreement;" Exhibit A.

[24] TGP. MPUC Docket No. 2014-00071. File No. 212. ECRC Proposal of Tennessee Gas Pipeline Company, LLC.

[25] TGP. Conference call with TGP, LEI, Commission staff. February 5, 2015; and Tennessee Gas Pipeline. MPUC Docket No. 2014-00071. File No. 263. Attachment A-2 "Precedent Agreement."

[26] TGP. MPUC Docket No. 2014-00071. File No. 263. Attachment A-2.

For the Access Northeast project, the "replacement customer" to whom Maine may release its capacity must be an electric generator.[27] The rationale for this is that the ERS contract is designed for specific delivery points, the "producer aggregation areas" that may have laterals that are bottlenecked under coincident peak conditions, and Access Northeast is designed to reduce the bottlenecks. [redacted][28] Access Northeast is being marketed to electric (rather than gas) distribution companies.[29]

6.2 Project routes

Project routes include receipt points and delivery points, and flexibility and options related to these points. Primary receipt and delivery points refer to the primary path of a pipeline, defined by the receipt and delivery points specified on the FT contract and the direction of flow represented by those points. Gas flowing on the FT primary path has the highest priority on the pipeline. Gas flowing on the primary path between secondary receipt or delivery points has a lower priority than primary FT service, but a higher priority than interruptible service. Figure 34 summarizes the project routes offered by the ECRCs.

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[27] Spectra. MPUC Docket No. 2014-00071. File No. 215. Exhibit A "Rate Schedule ERS Electric Reliability Service."
[28] Spectra. Conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.
[29] Spectra. Conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015; and *Megawatt Daily*. "National Grid, Eversource to lock in pipeline space." February 19, 2015.

Figure 34. Project routes' receipt and delivery points

Project name	Atlantic Bridge	Access Northeast	Continent to Coast	Northeast Energy Direct
Project route(s)	Mahwah/Ramapo to Beverly Mass; north into Maine on M&NP	Mahwah/Ramapo to power producer aggregation areas	Dawn-Dracut; Niagara/Chippawa-to-Dracut; Wright-to-Dracut	Wright to Dracut
Primary delivery point	Beverly	Designated power plant aggregation areas	Dracut	Dracut
Secondary delivery points	[redacted]			

Sources:
Atlantic Bridge: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. December 5, 2014.
Access Northeast: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014;
C2C: MPUC Docket No. 2014-00071, File No. 213: PNGTS. "ECRC Proposal December 5, 2014, PNGTS C2C Project."
NED: MPUC Docket No. 2014-00071, File No. 212: TGP. ECRC Proposal of Tennessee Gas Pipeline Company LLC, December 4, 2014. File No. 263. Exhibit B to Precedent Agreement Negotiated Rate Agreement, Negotiated Rate Option 2.

6.2.1 Atlantic Bridge

The Atlantic Bridge project offers primary receipt points at Mahwah, NJ and Ramapo, NY (designated as [redacted] in Figure 35) as well as Brookfield, CT (designated as [redacted]) and at Head of G System (designated as [redacted]) in eastern MA.[30] Each of these routes has a different FT rate associated with it.

[30] Spectra: MPUC Docket No 2014-00071, File No. 215: "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit E "Non-binding term sheet."

Figure 35. Atlantic Bridge proposed route (confidential information)

Redacted

Source: Spectra. MPUC Docket No. 2014-00071. File No. 215. Exhibit G.

Atlantic Bridge offers 120 delivery meters that could be chosen as primary delivery points. Spectra's ECRC proposal recommends that Beverly, MA (designated as [redacted]) be chosen as the primary delivery point. The other meters are offered on a secondary basis in any case, and because most of them are on the primary path (i.e., on the way from the receipt points to Beverly) they will have a high scheduling priority for secondary deliveries.[31] Primary receipt and delivery points exclude some portions of laterals which are on separate tariffs.[32] These separate tariffs reflect existing service on laterals, some of which serve power plants. Secondary receipt and delivery points are available, except at points that are under the separate tariffs.

This is an entirely "brownfield" route—the pipeline and rights of way are already in place. Construction involves expanding compression facilities and replacing smaller-diameter pipe with larger-diameter pipe, and looping.

For delivery from Massachusetts to Maine, gas would flow on the M&NP system from Beverly MA, to a number of delivery point options, including to Baileyville at the Canadian border. The Beverly-to-Baileyville route is a separate, additional FT (reservation rate) of [redacted]/Dth per day.[33]

[31] Spectra: MPUC Docket No 2014-00071, File No. 215: "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. December 5, 2014. p. 18.

[32] Spectra. MPUC Docket No. 2014-00071. File No. 215. "Rate Schedule AFT-1 Form Transportation Service" and Exhibit A "Rate Schedule ERS Electric Reliability Service," p.1.

[33] Spectra. MPUC Docket No. 2014-00071. File No. 215. Exhibit E. "Non-binding Term Sheet Atlantic Bridge Project."

6.2.2 Access Northeast

The Access Northeast project offers primary gas supply receipt points at Mahwah/Ramapo, as well as Wright. [redacted].[34]

Primary delivery points are four proposed power plant aggregation areas (see Figure 36). [redacted][35] [redacted][36] The intent of the ERS is that EDCs buy gas on behalf of the generators. Primary receipt and delivery points exclude some portions of laterals ([redacted]) which are on separate tariffs.[37] Secondary receipt and delivery points are available except at points that are under the separate tariffs.

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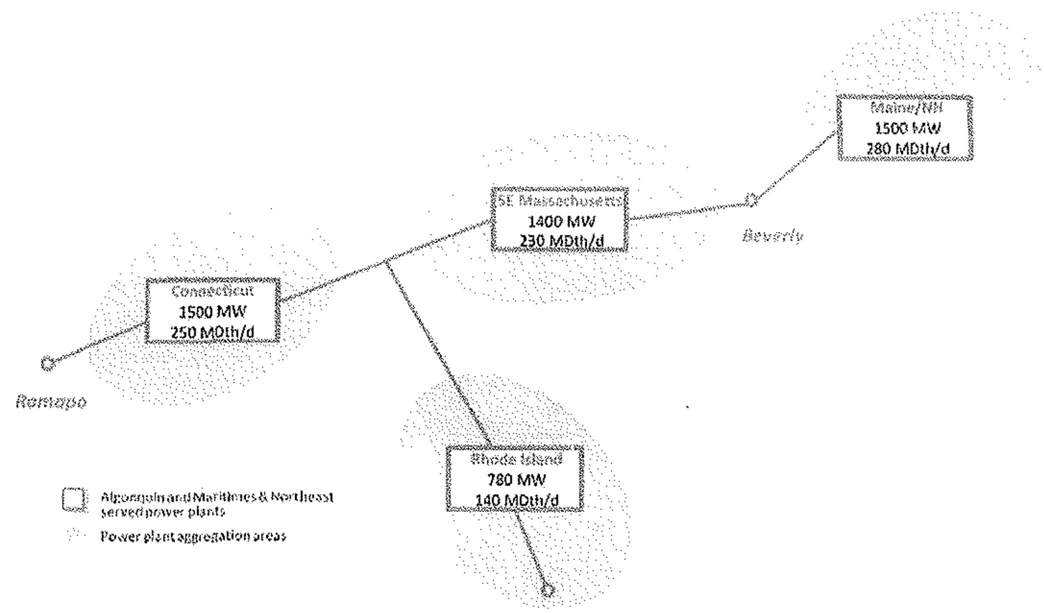
[34] Spectra. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; MPUC Docket No. 2014-00071. File No. 215. Exhibit B Non-binding term sheet Access Northeast Project-Electric Reliability Service."

[35] Spectra. Conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

[36] Spectra. Conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

[37] Spectra. MPUC Docket No. 2014-00071. File No. 215. "Rate Schedule AFT-1 Form Transportation Service." p. 1 and Exhibit A "Rate Schedule ERS Electric Reliability Service." p.1.

Figure 36. Access Northeast primary delivery points



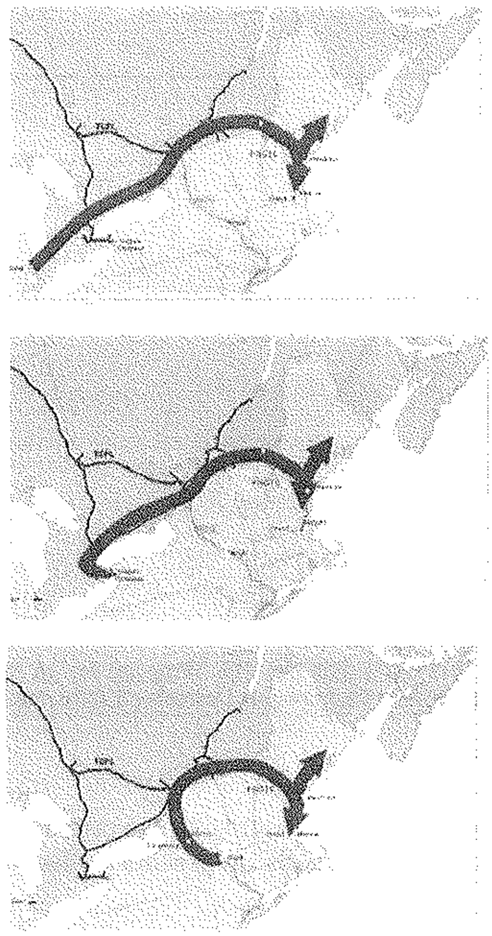
Source: Spectra. MPUC Docket No. 2014-00071. File No. 215. "Proposal for an Energy Cost Reduction Contract" submitted to the Maine Public Utilities Commission. December 5, 2014, Public Version at 8.

6.2.3 PNGTS C2C

PNGT offers the choice of several routes, depending on the primary receipt point chosen by the shipper. Each route involves contracting for FT on pipelines other than PNGTS, in addition to PNGTS (see Figure 37):

- Dawn receipt point: TCPL system to Pittsburg NH, south on PNGTS through New Hampshire, south through Maine, to Westbrook Maine and south to Beverly MA and/or north through Maine on M&NP;
- Niagara/Chippawa receipt point: TCPL system to Pittsburg NH, then south on PNGTS as above; and
- Wright receipt point: Iroquois pipeline to TCPL to Pittsburg NH, then south on PNGTS.

Figure 37. PNGTS C2C proposed routes



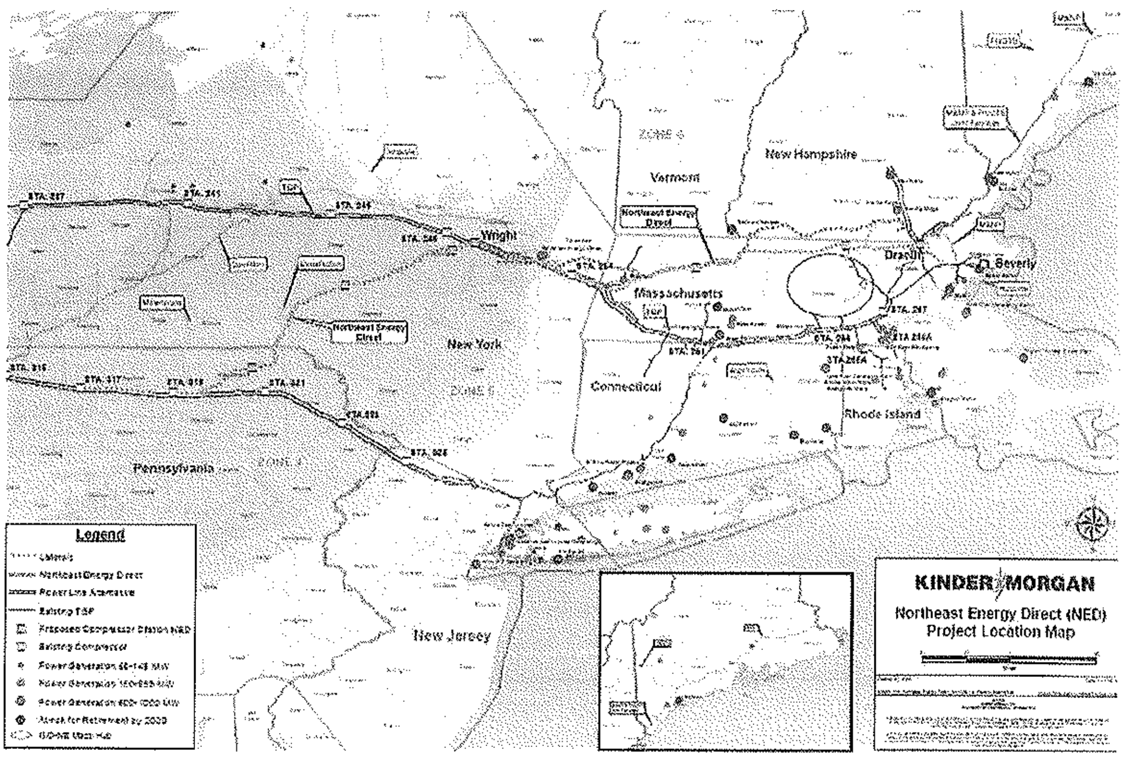
Source: PNGTS. MPUC Docket No. 20014-00071. File No. 213. "ECRC Proposal, PNGTS C2C Project." December 5, 2014, Public Version at 11, 13, 14.

PNGTS' ECRC offers a variety of delivery points on its system in New Hampshire, Maine and Massachusetts. The FT rates quoted in the ECRC refer to primary delivery in Westbrook, Maine; however, as it is a postage stamp rate, the rate extends to cover delivery points as far south as the end of the Joint (M&NP and PNGTS) Facilities in Dracut, MA.[38] In other words, the same price applies to delivery to Dracut and Westbrook.[39]

6.2.4 TGP NED

The primary receipt point for the NED project is Wright. The route traverses western MA, and southern New Hampshire, with primary delivery at Dracut, MA. Part of this route will involve green field construction, though much of that is intended to be within existing rights of way, including rights of way for electric power transmission. Figure 38 shows the proposed route; currently the "Power Line Alternative" route (designated in green through southern New Hampshire) is the one that is being pursued by the developer.

Figure 38. TGP/KM Northeast Energy Direct proposed route



Source: TGP. MPUC Docket No. 2014-00071. File No. 212. Attachment A-5 (Public).

NED also offers a second option, a Wright-"downstream of Dracut" delivery points. The primary downstream delivery points would be on TGP's 200 Line Zone 6 (Massachusetts). This offers more options for primary and secondary delivery points.

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[38] PNGTS. MPUC Docket No. 20014-00071. File No. 213. "ECRC Proposal, PNGTS C2C Project." December 5, 2014.
[39] PNGTS. Conference call with PNGTS, LEI, commission staff. February 5, 2015.

6.3 Firm transportation cost

The cost of FT is made up of two components: demand (or reservation) charges, and commodity charges. Demand is a monthly charge to reserve capacity, and the shipper (customer) pays it whether or not they ship the gas. Commodity charges are based on the quantity of gas that flows during a month. Commodity charges are specified in the pipeline tariffs—as they are small percentage of the cost of gas, we will simply refer to reservation charges when we use the term FT costs. For the Access Northeast project, the [redacted] reservation charge also includes the supply reservation charge (i.e., space in LNG storage facilities) (see Figure 39).

The reservation charge is intended to recover the capital expenditure to build or expand facilities. Often the customer's risk of capital cost overruns is capped at an agreed-upon level. [redacted][40] PNGTS does not provide this as there is no construction needed on the PNGTS leg or on the Iroquois leg of the route; there are no construction-based adjustments to the TCPL rate on the Waddington-to-East Hereford leg ([redacted]Dth per day).[41] The other TCPL rates are tariff rates on TCPL, not project-specific rates.

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[40] Spectra Energy. Conference call/meeting with Spectra, LEI, and Commission staff. February 12, 2015.

[41] Armstrong, Cynthia. Director of Marketing and Business Development, Portland Natural Gas Transmission. Email communication. March 10, 2015.

Figure 39. Project reservation (FT) costs

Project	Primary route	Reservation charge (dollars per Dth/day)	Supply component	Maximum reservation charge if worst-case cost overruns (dollars per Dth/day)	Notes
Atlantic Bridge	Mahwah-Beverly	[redacted]	n/a	[redacted]	[redacted]
	Brookfield, CT-Beverly	[redacted]	n/a	[redacted]	[redacted]
	Head of G System-Beverly	[redacted]	n/a	[redacted]	[redacted]
	Beverly-Baileyville on M&NP	[redacted]	n/a	n/a	
Access Northeast	Mahwah-Aggregation Area	[redacted]	"Supply Component" includes space charge, injection and withdrawal	[redacted]	[redacted]
Continent to Coast Dawn-Maine (Dracut)	TCPL PNGTS	[redacted]			
	Total	[redacted]	n/a	n/a	[redacted]
Niagara-Maine (Dracut)	TCPL PNGTS	[redacted]			
	Total	[redacted]	n/a	n/a	[redacted]
Wright-Maine (Dracut)	IGTS TCPL PNGTS	[redacted]			
	Total	[redacted]	n/a	n/a	[redacted]
Northeast Energy Direct	Wright-Dracut	[redacted]	n/a	[redacted]	[redacted]
	Wright-downstream of Dracut	[redacted]	n/a	[redacted]	[redacted]

Sources:

Atlantic Bridge: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit E "Non-binding Term Sheet Atlantic Bridge Firm Transportation Service"; "Rate Schedule AFT-1 Firm Transportation Service;" and "Statement of Negotiated Rates."

Access Northeast: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; Exhibit B "Non-binding Term Sheet Access Northeast Project-Electric Reliability Service;" and Conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

C2C: MPUC Docket No. 2014-00071, File No. 213: PNGTS. "ECRC Proposal December 5, 2014, PNGTS C2C Project;" Conference call/meeting with PNGTS, LEI, Commission staff, February 5, 2015.

NED: MPUC Docket No. 2014-00071, File No. 212: TGP. "ECRC Proposal of Tennessee Gas Pipeline Company LLC," December 4, 2014; Conference call/meeting with TGP, LEI, Commission staff, February 5, 2015. File No. 263. Appendix A to Negotiated Rate Agreement.

6.4 Construction attributes and schedules

Pipeline projects can take longer to permit or construct than developers' initial in-service dates reflect. Both brownfield and greenfield construction can face delays or complications in permitting and/or construction, which can increase costs. Existing gas pipelines that form the basis of brownfield projects often lie in densely populated areas. This can make it more complicated to access and replace facilities, even though the facilities are in existing rights-of-way.[42] Sometimes service to existing customers has to be interrupted, in order to expand the facilities. Greenfield projects are sometimes more straightforward to construct, but the permitting and rights-of-way can still take time.

Most of the ECRC proposals have some mitigation of customer risk, in the form of caps on the maximum reservation rate as noted above, and protections in case of project delays.

6.4.1 Atlantic Bridge

The Atlantic Bridge is a brownfield project that uses the Algonquin mainline and involves replacing smaller-diameter pipeline segments with larger-diameter pipeline segments ("lift and re-lay"), adding pipe parallel to existing pipe ("looping") and expansion of compression.[43] Risk is mitigated with a cap on reservation rates as noted earlier ([redacted] reservation rate) (see Figure 40).

[redacted].[44] Atlantic Bridge's open season has closed, and FERC pre-filing was completed in February 2015.[45]

Figure 40. Construction and proposed schedule

[42] Davenport, Mark. MPUC Docket No. 2014-00071. File No. 212. "Construction Discussion for the Northeast Energy Direct Pipeline Project."

[43] Spectra. MPUC Docket No. 20014-00071. File 215. Exhibit H "Proposed Atlantic Bridge Project Facilities based on 240,000 Dth/d project scope."

[44] Spectra. MPUC Docket No. 20014-00071. File 215. Exhibit E "Non-Binding Term Sheet."

[45] FERC Docket No. PF15-12.

Bidder Project name	Spectra Energy Atlantic Bridge	Spectra Energy Access Northeast	PNGTS Continent to Coast	TGP/KM Northeast Energy Direct
Project size million cubic feet per day ("MMcfd")	220	[redacted]	[redacted]	1,200
Greenfield/Brownfield?	Brown	Brown	Brown	Green+brown
Does construction include expansion of laterals?	No	Yes	No	[redacted]
Developer's proposed in-service date	Nov-17	Nov-18	Nov-17	Nov-18
Current stage of process	Open season closed Feb 2015 (FERC pre-filing Docket # PF15-12)	Open season closed May 2015	Open season closed Feb 2015	FERC Pre-filing (FERC Docket # PF14-22)
Project commitment risk mitigation	[redacted]	[redacted]	[redacted]	[redacted]

Sources:

Atlantic Bridge: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; "Rate Schedule AFT-1 Firm Transportation Service." Exhibit F "Pro Forma Precedent Agreement for Discussion Purposes Only."

Access Northeast: MPUC Docket No. 2014-00071, File No. 215: Spectra Energy. "Proposal for an Energy Cost Reduction Contract" Submitted to the Maine Public Utilities Commission. Spectra Energy. December 5, 2014; and Conference call/meeting with Spectra, LEI, Commission staff. February 12, 2015.

C2C: MPUC Docket No. 2014-00071, File No. 213: PNGTS. "ECRC Proposal December 5, 2014, PNGTS C2C Project; and Conference call with PNGTS, LEI, Commission staff, February 5, 2015.

NED: MPUC Docket No. 2014-00071, File No. 212: TGP. ECRC Proposal of Tennessee Gas Pipeline Company LLC, December 4, 2014; and Conference call with TGP, LEI, Commission staff, February 5, 2015.

6.4.2 Access Northeast

The Access Northeast ERS service uses the Algonquin mainline (same as Atlantic Bridge) as well as portions of M&NP. However, it also includes changes to the mainline as well as to laterals to accommodate use of LNG—to bring the LNG from storage facilities to support peak demand periods. These laterals serve the four "producer aggregation areas" (Connecticut [redacted]; Rhode Island [redacted], SE Massachusetts [redacted], and Maine/NH plants served by M&NP).

Access Northeast proposes [redacted] storage capacity to support delivery [redacted].[46] Access Northeast construction does not include any expansion of LNG storage; Spectra has said the project is relying on unused capacity in New England's roughly 18 Bcf of existing LNG storage. [redacted].

Spectra has said they expect Access Northeast to go into service November 2018. Open season for the project closed in February 2015. Spectra representatives noted that if it turns out that LNG facilities have to be built [redacted], that itself would not increase the [redacted] Dth per day reservation charge.[47]

6.4.3 PNGTS C2C

PNGTS' C2C project does not involve any construction on the PNGTS system or the Iroquois system. It is designed to help remove bottlenecks on the pipeline that PNGTS relies on to provide it with gas: namely, the TransCanada Pipeline (TCPL) system. PNGTS needs TransCanada to make improvements to boost pressure and flow into the PNGTS receipt point at Pittsburgh, NH. PNGT's certified capacity is currently 168 Mmcfd, but it could be 300-350 MMcfd if pressure were adequate on TransCanada.[48]

This is entirely a brownfield project: PNGTS will operate at higher pressure (no construction, no addition of compression). The TCPL leg involves looping and adding more compression and IGTS involves pipeline reversal, with no addition of compression.

For its part, TCPL needs long-term contractual commitments to make these expansions. Thus, the C2C ECRC, in all three of its route options, includes FT on TCPL. PNGTS reports that they expect the C2C project to go into service by November 2017, based on a generic project schedule that represents a project of the scope under consideration.[49]

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[46] Spectra. Conference call/meeting with Spectra, LEI, and Commission staff. February 12, 2015.

[47] Spectra. Conference call/meeting with Spectra, LEI, and Commission staff. February 12, 2015.

[48] PNGTS. Conference call with PNGTS, LEI, and Commission staff. February 5, 2015; and TransCanada. "Portland Narural Gas Transmission System announces Continent to Coast (C2C) Expansion Project. http://www.trnascanada/news-release-article.html?id=1703748. April 1, 2013.

[49] PNGTS. MPUC Docket No 2014-00071, File No. 213. "ECRC Proposal December 5, 2014, PNGTS C2C Project." p. 16.

6.4.4 TGP NED

The NED project involves the most greenfield construction of the four ECRCs.[50] TGP plans to use existing utility corridors, and describes the project as consisting of "approximately 188 miles of new and co-located mainline pipeline facilities, including about 53 miles of pipeline generally co-located with TGP's existing 200 Line and an existing power utility corridor in western New York...; approximately 64 miles of pipeline generally co-located with an existing power utility corridor in Massachusetts; and approximately 71 miles of pipeline generally co-located with an existing power utility corridor in southern New Hampshire, extending east to the proposed Dracut, Massachusetts Market Path Tail Station. With these changes, approximately 90% of the route of the NED Project will be within or along existing rights of way."[51]

The NED proposal (Option 1 and Option 2) includes expansion/additions of two laterals from Dracut (one towards Beverly; one to M&P); a lateral from the TGP 200 Line to southern Worcester county in Massachusetts, and another lateral from the NED line from southern New Hampshire to Leominster/Lunenburg in northern Worcester county. For Option 2 (delivery points downstream of Dracut) TGP representatives noted that some further expansions of laterals could be provided.

The developers are planning for an in-service date of November 2018 for NED. The cost risk to Maine is mitigated by a cost cap on the reservation rate.

[redacted][53]

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[50] TGP. MPUC Docket No. 2014-00071. File No. 212. Attachment A-6. "Tennessee Gas Pipeline Adopts New Route Via Existing Utility Corridors in New Hampshire and New York for Proposed Northeast Energy Direct Project." December 5, 2014.

[51] TGP. MPUC Docket No. 2014-00071. File No. 212. "ECRC Proposal of Tennessee Gas Pipeline Company, LLC." December 4, 2014.

[52] TPG. Attachment A-3 Exhibit A to Precedent Agreement.

[53] TGP. MPUC Docket No. 2014-00071. File No. 212. Attachment 2 "Overview of Offer," p. 4.

7 Appendix B: Modeling approach and assumptions

7.1 Definition of the MECRA Baseline outlook

The MECRA Baseline outlook is defined as the case in which Maine takes no action—i.e., does not accept any ECRC proposals. The purpose of the MECRA Baseline outlook is to establish the baseline against which to compare the ECRC project cases.

7.2 Methodology for gas market modeling

The GPCM model is widely-used integrated network model of the North American gas market. It is based on pre-programmed supply cost curves, demand curves, and pipeline and storage tariffs and capacity.[54] Using these inputs, GPCM projects gas prices for supply-area and market-area hubs. GPCM's 4Q2014 database provides the foundational data used in the MECRA Base Case.

7.3 Gas supply curves

GPCM incorporates pre-programmed supply curves that are keyed to an assumed level of "medium production" potential of a supply basin and an assumed gas price. There are two other points, a low production potential point and a high production point, and a corresponding price for each of these, for each curve. The shape of a region's supply curve changes over time. For a mature supply region (such as the Louisiana Gulf Coast area), the supply curve shifts leftward (resulting in less supply at a given price level). For a new and prolific area such as the Marcellus region, the supply curve can shift rightward over time (resulting in more supply a given price level). For the MECRA Baseline outlook as well as for each of the ECRC cases, LEI used the built-in gas supply curves and supply projections provided in GPCM's 4Q2014 data set.

7.4 Gas demand projections

LEI used the demand projections provided in the 4Q2014 GPCM data set for New England as a whole. This gas demand outlook incorporates a very slight decline of 0.1% on an annual average basis from 2015 through 2028 (see Figure 41). This is the demand outlook that drives the Baseline and ECRC gas price outputs of the GPCM model.

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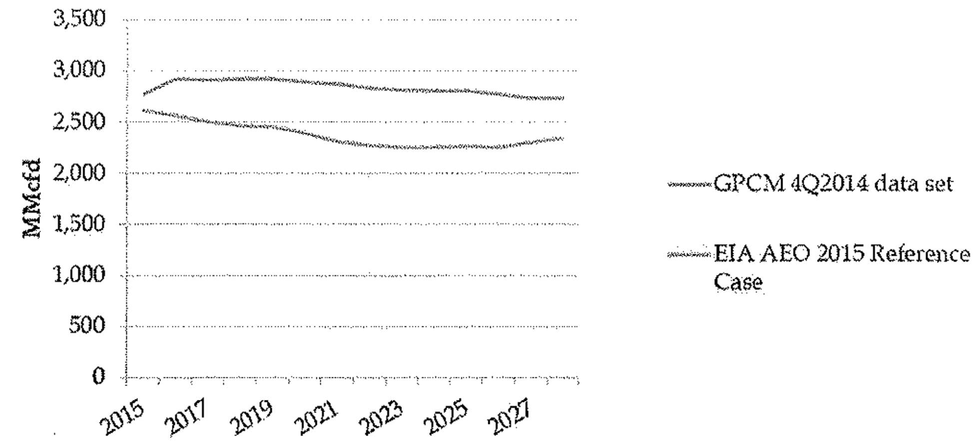
[54] http://www.rbac.com/ProductsServices/GPCMGasModel/tabid/80/Default.aspx.

Figure 41. GPCM and EIA AEO New England gas demand outlooks



Source: GPMC 4Q2014 dataset; EIA AEO 2015 http://www.eia.gov/beta/aeo/#/?id=2-AEO2015&region=1-1&cases=ref2015&start=2012&end=2040&f=A&linechart=&map=2-AEO2015.21.&ctype=map

As a point of comparison, the EIA's Annual Energy Outlook ("AEO") 2015 Reference Case shows gas demand in New England declining at an annual average rate of 0.9% from 2015 through 2028.[55] This is driven by falling demand from the electric power sector, which EIA projects at an annual average of -1.5% from 2015 through 2028; combined with weak growth from the commercial sector (0.2% annually); a decline of -0.4% for the residential sector; and 0.5% average annual growth from the industrial sector.

LEI feels EIA's Reference Case outlook for gas demand growth in New England is too low. LEI's MECRA Baseline power model (POOLMod) projects gas demand from the power sector in New England to decline at an annual average rate of 2.4% from 2016-2028—somewhat faster than EIA projects. This is driven by increasing efficiency as the gas fleet expands, as well as the assumed addition of transmission from Quebec as discussed earlier. However, this decline can be somewhat offset by growth that we expect in residential and commercial demand. For residential and commercial demand, LDCs in New England have already contracted for an additional 542.1 MMcfd of FT (on TGP CT, AIM, and Atlantic Bridge's 110 MMcfd committed), for example. Residential and commercial consumption account for about 45% of consumption in New England, and power consumption of gas is about 40%.[56] Thus the increase in residential and commercial demand will help offset the decline in power demand (see Figure 42). Thus LEI feels that the GPCM outlook (shown in Figure 41 previously) is a more reasonable baseline than the EIA AEO Reference Case outlook, so we used the GPCM outlook to drive the outlook for gas prices.

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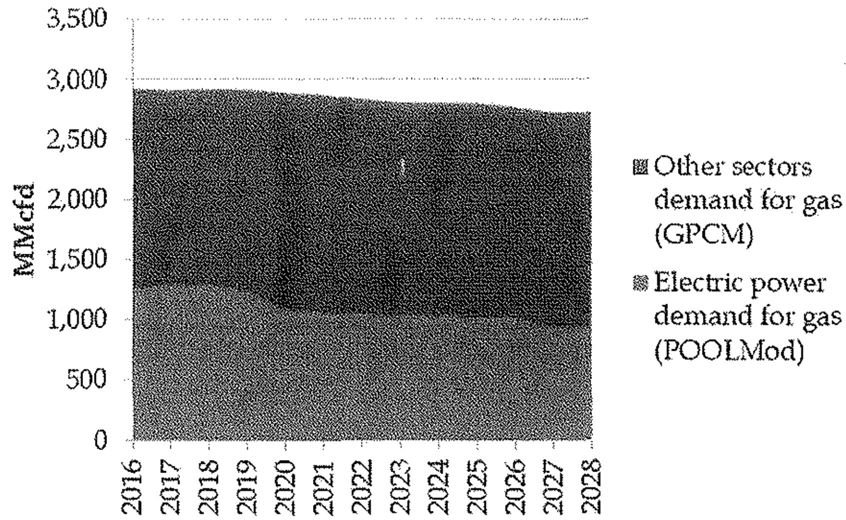
[55] http://www.eia.gov/beta/aeo/#/?id=2-AEO2015&region=1-1&cases=ref2015&start=2012&end=2040&f=A&linechart=&map=2-AEO2015.21.&ctype=map

[56] EIA "Natural gas consumption by end use." http://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_m.htm

Figure 42. Total New England gas demand outlook, GPCM (residential, commercial, industrial) and POOLMod (electric power)



We further refined the gas demand projections for the state of Maine, by adjusting the GPCM data:

- We allowed GPCM's Maine residential sector gas demand (7 MMcfd in 2015) to increase 1.5% annually from 2015 onward (GPCM's pre-programmed Maine residential demand had zero growth through 2028);
- We adjusted GPCM's Maine industrial gas demand forecast to account for the closure of three large pulp and paper mills (the Verso Bucksport paper mill, the Old Town Fuel and Fiber pulp mill, and the Great Northern paper mill in East Millinocket) in 2014. As of 2013, there were 12 pulp and paper mills operating in Maine. Using estimates of energy consumption per employee in NAICS codes 32211-32213 (pulp and paper manufacturing) from the EIA's Manufacturing Energy Consumption Survey, and the number of employees in this sector in Maine in 2013 (5,507) from the US Census Bureau Annual Survey of Manufactures, we estimate that the pulp and paper sector's gas consumption was 64 MMcfd in 2013, or about 73% of Maine's industrial gas consumption that year. Using the reported number of jobs lost owing to the shutdown of the three mills (a total of 950), we estimate that the closure of the 3 mills reduced industrial sector gas demand by 11.7 MMcfd.
- We subtracted an annual average 10.9 MMcfd of hedged demand (not exposed to wholesale gas price changes) from GPCM's projection of commercial demand in Maine. In reality this 10.9 MMcfd is likely spread across the three sectors; we subtracted it from the commercial sector simply for convenience.

LEI made these adjustments order to get a more accurate estimate of the benefits of lower gas prices to Maine customers. These adjustments applied to the MECRA Baseline outlook and all the ECRC cases. We did not feed these adjustments back into the GPCM database, thus they do not impact the outlook for gas prices in the MECRA Baseline outlook or any of the ECRC cases. We feel this is reasonable, as the small adjustments to Maine amount to a tiny percentage of New England's 2,400 MMcfd of gas consumption.

7.5 Gas pipeline capacity expansions

The baseline is our view of a plausible future for pipeline capacity in New England, absent any awarded ECRCs from Maine. Therefore we used the following criteria to determine how much pipeline capacity that was not already in service (as of February 2015) to include in the baseline:

- Capacity that is fully contracted is included; and
- Capacity that does not depend on an ECRC to go forward is included.

Thus the Baseline outlook includes pipeline capacity under development that has firm contracts. These are:

- Tennessee Gas Pipeline Connecticut expansion (72 MMcfd), in service November 2016);
- Algonquin Incremental Market (342.1 MMcfd, in service November 2017): and
- Atlantic Bridge (non-ECRC portion) (110 MMcfd, in service November 2017).

These expansions are in addition to the capacity that exists in New England as of 2014 (see Figure 43).

Figure 43. Gas pipeline transmission capacity into New England, 2014

Pipeline	From	To	MMcfd 2014
Algonquin Gas Trans Co	New York	Connecticut	1,355
Iroquois Pipeline Co	New York	Connecticut	866
Maritimes/Northeast PL Co	New Brunswick	Maine	865
Portland Gas Trans Co	Quebec	New Hampshire	216
Tennessee Gas Pipeline Co	New York	Connecticut	150
Tennessee Gas Pipeline Co	New York	Massachusetts	1,169
Total			**4,621**

Source: Energy Information Administration, "EIA-StatetoStateCapacity.xls" at http://www.eia.gov/naturalgas/data.cfm

There are many supply-area pipeline expansions underway in the Northeast. The largest of these may be important to the accessibility of gas to pipelines that serve New England, as they may affect gas prices at some of the receipt points offered. Many expansions are already included in the GPCM model, and we included them in the MECRA Baseline outlook. Several of the largest are noted below:

- The Constitution pipeline under development at 650 MMcfd from the Marcellus area to Wight, New York, in service by November 2017;[57]
- ET Rover, a 3.25 billion cubic feet per day ("Bcfd") pipeline from the Marcellus area to Dawn, Ontario, in service November 2017; and
- The Nexus pipeline, assumed 1 Bcfd from Marcellus to Dawn, November 2017.

A proposed supply-area portion of the NED project would expand the same path as Constitution (Marcellus gas supply area to Wright). The supply-area expansion of NED is in early stages, and had not yet held had an open season. GPCM does not include the proposal NED expansion, so we did not include it in the MECRA Baseline outlook.

In the modeling, we used the in-service dates for pipeline projects as cited by the project developers. Planned in-service dates are targets, and these dates can slip by several months or even years; pipeline projects can take longer to permit or construct than developers' initial in-service dates reflect. Thus, the timing of completion and in-service dates for pipelines not yet completed are key source of uncertainty that affect whether the results of the MECRA Baseline outlook model will reflect actual future conditions, and will affect the value of an ECRC to Maine.

7.6 Methodology for modeling wholesale electric energy and capacity markets

LEI used our proprietary simulation model, POOLMod, to forecast wholesale energy prices in ISO-NE. POOLMod simulates the dispatch of generating resources in the market subject to least cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission. We assume perfect competition in that the energy offers of generators and external suppliers are based on marginal costs of production or competitive opportunity costs.

POOLMod consists of a number of algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow-pricing, commitment of resources and dispatch. POOLMod first evaluates the available generation, then determines the marginal costs of generation by resource, and finally dispatches the resources needed to meet hourly demand across the system in a least cost manner, while taking into account operational constraints on generation and congestion on the transmission system. In this way, POOLMod's algorithms, in the aggregate, simulate the Locational Marginal Price ("LMP")-setting process that ISO-NE performs as part of its day-ahead and real-time energy markets.

For Forward Capacity Auction ("FCA") prices, LEI uses the parameters of the downward sloping demand curve set by ISO-NE. Each year, ISO-NE publishes a forecast for the Net Installed Capacity Requirement ("NICR") and LEI extrapolates this in line with expected peak demand, maintaining a 14.3% reserve margin. ISO also published a Net CONE estimate for the

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[57] Constitution Pipeline <www.http://constitutionpipeline.com/> and *Gas-Electric System Interface Study, Target 2 Report, Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems* Prepared for the Eastern Interconnection Planning Collaborative. Levitan and Associates, Inc. September 30, 2014.

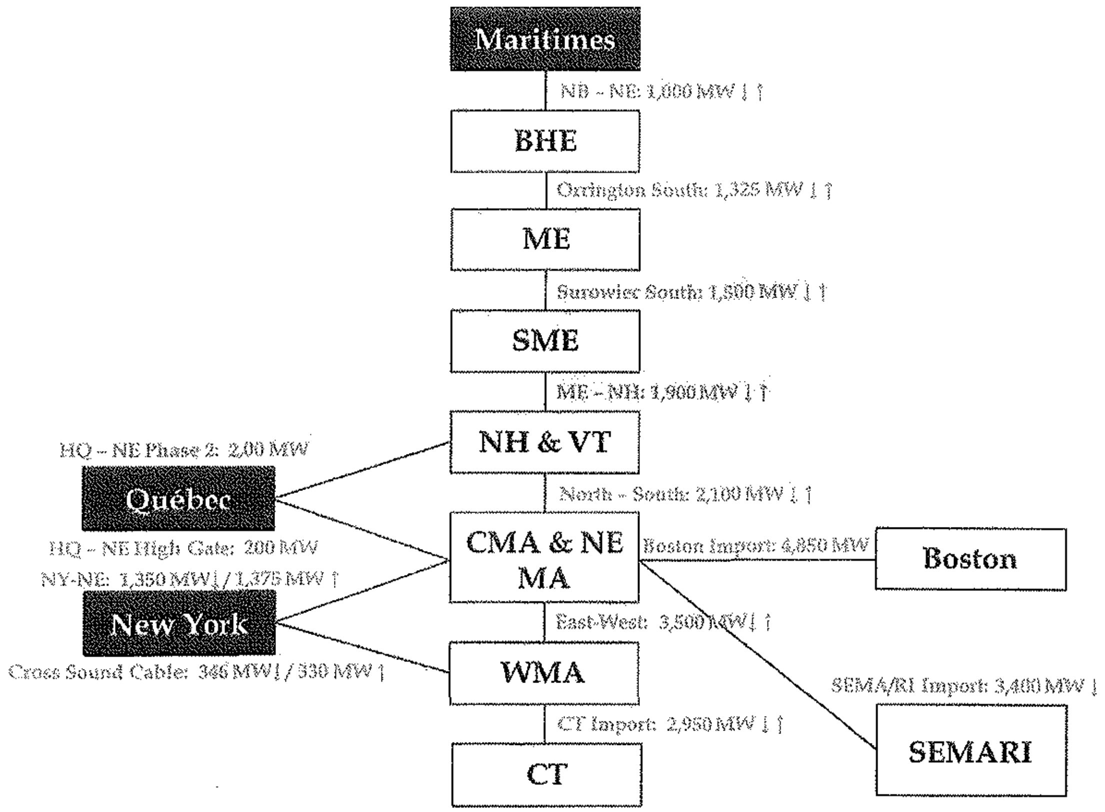
FCA #10. Once Net CONE is determined, LEI adds new entry when it is economic. The decision to retire a plant is also made on the basis of whether a plant can reasonably meet its minimum going-forward costs in the energy and capacity market.

7.7 New England power system topology

LEI's model of the New England power grid uses nine zones in ISO-NE: (i) Bangor Hydro Electric ("BHE"); (ii) Maine ("ME"); (iii) Southern Maine ("SME"); (iv) New Hampshire/Vermont ("NH/VT"); (v) Central and Northern Massachusetts ("CMA/NEMA"); (vi) Western Massachusetts ("WMA"); (vii) Connecticut, Southwest Connecticut, and Norwalk ("CT"); (viii) Boston ("NB"); (ix) Southeast Massachusetts/Rhode Island ("SEMARI"). This is consistent with the market topology used by ISO-NE in their long-term planning models and the location of the most binding transmission constraints.[58] Figure 44 illustrates the interconnections modeled (the transmission limits are sourced from RSP 2014).

[58] For long-term planning purposes, ISO-NE models the ISO-New England Control Area ("NECA") on the basis of thirteen sub-regions defined by binding transmission constraints. For modeling, the market topology is simplified, while being consistent with ISO-NE's approach. CT, SWCT and NOR are modeled as one zone. NH and VT are modeled as one zone, and SEMA and RI are modeled as one zone.

Figure 44. Regional transmission interface limits in 2016



In modeling a particular market, when we look at the external interties, we explicitly take into account the operating limits set by the ISO for the target market being studied. Neighboring ISOs may have different rating limits for those same interties based on their standards. Discrepancies are not likely to impact the results substantially since import/export schedules are designed with a focus on the average level of flows rather than the absolute limits.

Source: ISO-NE RSP 2015 Base Transfer Limits.

7.8 Transmission assumptions

LEI's Baseline outlook includes major transmission upgrades and additions over the forecast horizon. We assume that the Integrated Reliability Project ("IRP") portion of the New England East-West Solution ("NEEWS") will be completed and start operation in 2016. This will increase the transmission capacity at the CT Import interface between the WMA and CT sub-regions.

Thus the Baseline outlook includes:

- the IRP project, which expands the East-West interface from 2,800 MW to 3,500 (by 700 MW) and raises also the limit in the opposite direction (West to East) from 1,000 MW to 2,200 MW (by 1,200 MW), beginning in 2016; and,

- the Greater Boston Solution North-South interface – we assume an expansion from 2,100 MW to 2,675 MW on the North-South interface as a result of these transmission upgrades by 2018.
- ISO-NE has conducted a wind integration study for 2024, which states that Orrington-South interface could increase to 1,760 MW if wind generation in the Wyman Hydro region were reduced by 300 MW. In addition, Surowiec-South could be increased to 2,100 MW and Maine-New Hampshire could increase from 2,000 MW to 2,300 MW. LEI has made these additional upgrades starting in 2024, which is the study period.

7.9 Power imports and exports

With combination of announced and approved retirements of power generation capacity (discussed later) as well as forecasts for load growth, it is recognized by ISO-New England that New England will need more energy resources.[59] These resources could be in the form of transmission lines or generating plants. Because there are a number of proposals for transmission lines, it is likely that at least one or two large lines will be built.[60] Therefore, LEI's Baseline outlook includes a new generic transmission project bringing energy (and capacity) into ISO-NE from Canada. This is modeled as a 1,000 MW injection into northern New England, at a load factor of 83% (7,300 TWh of energy per annum), beginning in 2020.

7.10 New entry of generic generating capacity

LEI's modeling process assumes that generators make capacity investment decisions that are timed to load growth, as we are targeting an effective reserve margin on top of peak load. We first add renewable generation to meet the renewable portfolio standards set by state regulators. Next, we add new combined cycle natural gas units. We synchronized entry of these units with reliability reserve requirements set by ISO-NE.

In considering new entry, the model takes the following four criteria into account, namely: (1) the existing state RPS; (2) the Installed Capacity Requirement ("ICR") in New England;[61,62] (3) the LSRs of the four load zones under the current FCM market design; and (4) the economics of new entry based on LEI's new entry trigger price ("NETP") model.[63]

[59] Gordon van Welie, CEO, ISO-New England. "State of the Grid: Managing a System in Transition." January 21, 2015.

[60] http://www.nescoe.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf

[61] The ISO-NE determines the ICR level by using the probabilistic loss-of-load-expectation ("LOLE") analysis to ensure that the system has adequate future capacity resources. Source: *"ISO-NE Regional System Plan ("RSP") 2008"*. ISO-NE. Page 32.

[62] In New England, the ISO does not specify an explicit reserve margin; instead, it designates the Installed Capacity Requirement ("ICR"), which also serves as the procurement target for the Forward Capacity Market.

[63] In addition to the resource adequacy requirements motivating new entrants, entry is possible under the economic rationality rule if a generator can cover its all-in fixed costs from market-based revenues (although notably, incremental capacity substantially in excess of the ICR will not receive capacity revenues), and also the direction of political priorities (e.g., RPS), and other incentives (e.g., PTC).

The modeling process starts with the first two criteria and then refines and calibrates results to include the third criterion, taking into account revenues from both the energy and capacity markets as well as production tax credit ("PTC") and expected ancillary service revenues, where applicable. Ultimately, the mix of new entry is a function of market economics (i.e. profitability of generators) and policy priorities (i.e. renewables to meet RPS), as well as political realities (i.e. coal is unlikely to be a realistic candidate for these markets given the lack of commercial capability for carbon sequestration in New England, even though it could be competitive at high gas prices). Particularly, the RPS represents the state-level regulation which sets renewable targets on new and existing generating units by technology and year in which the unit was built. In the first step of calibrating the new entry mix, the general rule is to determine the minimum requirement for renewable capacity based on consideration of the state-specific RPS targets, projected energy consumption, and internal versus external RPS-eligible renewable capabilities.

After taking into account new entry to meet RPS, economic gas-fired generating capacity is then added to meet the installed capacity requirement ("ICR"), factoring in potential utilization rates, energy and capacity market revenues, and operating costs. New gas-fired generation is introduced if and when it is economically feasible given the simulated market dynamics (and in New England, these entry decisions are primarily done through the Forward Capacity Market). Based on this rationale, during the modeling timeframe LEI has added a 600 MW CCGT in 2027 and a 400 MW CCGT in 2029.

7.11 Electricity supply

Existing supply in ISO-NE is based on the 2015 CELT report, which provides the recent rated capacity for both summer and winter seasons, as of May 2015. This is supplemented with plant parameters (heat rates, variable O&M, forced outage rate, maintenance, ramp rates, etc.) from LEI's research and analysis, as well as data in commercially available databases such as EPA's Continuous Emissions Monitoring System ("CEMS") data. Going forward, for short-term new entry, we review the ISO-NE interconnection queue to incorporate known projects that have either contracts or other approvals to start construction.[64]

Regarding new renewable generation, in addition to known projects, in the Baseline outlook we assume that generic renewable resources are added to meet the region's various state RPS requirements. In total, nearly 2,000 MW of renewable capacity is added through 2029 in LEI's MECRA Baseline outlook, the vast majority of which (approximately 1,500 MW) is wind. Currently there is a very small amount of congestion in transmission for Maine renewables under normal operating conditions, and this is likely to increase with the additional wind build.

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[64] ISO-NE Interconnection Queue as of May, 2015. In particular, we critically consider project status and include on a specific basis only those projects that have approvals (e.g., I.3.9) and/or contracts, or have begun construction. Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff (the "Tariff") requires that project proposals need to demonstrate no significant adverse impact over the current electricity system operation <http://www.iso-ne.com/trans/pp_tca/forms/ppa_submittal_procedure.pdf>.

For the MECRA Baseline outlook we assume that Maine and New England build enough wind to meet RSP standards, and in the model, we upgrade transmission as needed and feasible, as this is the standardized approach used in LEI's Continuous Modeling Initiative semi-annual reports.

Announced retirements are all included in the Baseline outlook. These are based on FCAs and the Informational Filing for FCA#9 (see Figure 45). The Vermont Yankee nuclear plant retired at the end of 2014; and Brayton Point units will retire in 2017. In addition to announced retirements, if a plant cannot cover its minimum going-forward fixed cost for more than three consecutive years (in our capacity and energy model simulations), we retire it even if its retirement has not been announced. This includes Milford Power 1 and 2, Mass Power, and BG Dighton Power.

Figure 45. Announced plant retirements included in MECRA Baseline outlook

Unit	Fuel Type	Capacity (MW)	Retirement Year
VT Yankee	Nuclear	628	2015
Salem Harbor 1-3	Coal	310	2015
Kendall Steam 1-2	Natural Gas	34	2015
Holyoke/Cabot	Natural Gas	19	2015
Potter Diesel	Oil	2	2015
Brayton Diesel 4, Diesel	Oil	456	2017
Brayton Point 1-3	Coal	1101	2017
John Street	Oil	6	2017
Wallingford Refuse	Biomass	5	2018
Wheelabrator	Biomass	3	2018
Milford Power 1	Natural Gas	281	2024
Milford Power 2	Natural Gas	287	2025
Mass Power	Natural Gas	280	2026
BG Dighton Power	Natural Gas	185	2027

7.12 Oil and coal price assumptions

LEIs assumes the price of distillate is equal to heating oil forwards for the first two years of the forecast period, and escalated at the same rate as the EIA crude oil forecast in the long term. The price of residual oil is developed based on a multi-year average of the ratio of residual and distillate oil prices.

Given the diversity in coal sourcing, quality, and price, we use plant-specific coal price outlooks. We began with an estimate of 2014 actual delivered costs, taking into account the type of coal used at each plant (since each coal plant has different sulfur content levels and different contracts for price and transportation). We then escalate the estimated costs with the longer term trends for the commodity (the coal price forecast) and inflation rate from EIA AEO.

7.13 Emissions costs assumptions

Going forward, in the MECRA Baseline outlook we assume that any updated CSAPR or CSAPR replacement will cover all ISO-NE states by 2018. To model compliance costs for SO_2 and NO_X under CSAPR, LEI first examined each thermal plant's reported historical emission rates and the amount of allocated allowances. When a plant's annual emissions exceeded the amount of allocated allowances, LEI compared the cost of purchasing allowances versus installing emission control equipment. Where purchasing allowances proved cost effective, allowance costs were added to variable O&M costs. The SO_2 and NOx allowance prices are based on Bloomberg data for the short term and escalated at 2% annual inflation rate over the long term. If installing emissions control equipment is less costly on a net present value basis, a retrofit expenditure is considered for the plant, which increases the plant's minimum going forward fixed cost.

CO_2 emissions in New England are regulated under the Regional Greenhouse Gas Initiative ("RGGI"). Under RGGI, power plants with an installed capacity of over 25 MW must reduce their CO_2 emissions by 50% by the year 2020 relative to their 2005 emissions level. We assume that all ISO-NE states will auction 100% of their CO_2 allowances. Each plant is required to purchase an allowance to offset each ton of CO_2 it emits. The RGGI cap declines 2.5% each year from 2015 to 2020. It is expected that New England states will be in a good position to meet the objectives of the Clean Power Plan ("CPP"). Therefore, forwards for carbon prices have been used in the modeling up to 2020, after which RGGI prices are escalated by 2% to keep them constant in real terms (Figure 46).

Figure 46. Emission allowance price assumptions (nominal $/ton)

	CO_2	SO_2	NOx
2014	5.40	15.00	50.00
2015	5.51	15.30	51.00
2016	5.62	15.92	53.06
2017	5.80	16.24	54.12
2018	5.98	16.56	55.20
2019	6.17	16.89	56.31
2020	6.37	17.23	57.43
2021	6.50	17.57	58.58
2022	6.63	17.93	59.75
2023	6.76	18.28	60.95
2024	6.89	18.65	62.17
2025	7.03	19.02	63.41
2026	7.17	19.40	64.68
2027	7.32	19.79	65.97
2028	7.46	20.19	67.29
2029	7.61	20.59	68.64
2030	7.76	21.00	70.01

Sources: Bloomberg, LEI analysis.

7.14 Power demand assumes ISO-NE demand outlook

Demand data is directly sourced from ISO-NE's projected zonal demand published in the CELT 2015, based on the ISO-NE 50/50 (or Reference Case) demand forecast released in 2015. For 2025 and later, LEI extrapolates demand and peak load using growth rates from ISO-NE's forecast and the average growth rate of the last three forecast years. As noted previously, ISO-NE demand data is provided net of demand response and distributed solar PV. For the hourly load profile, LEI uses ISO-NE's hourly load forecast for 2015 for each sub region.

By definition, the 50/50 load forecast is an expected weather forecast – peak load under the 50/50 load forecast has a 50% chance of being exceeded. Major assumptions and conditions, including weather, are assumed to approach or approximate the long run average.

7.15 Integrated modeling process

Although both the GPCM and POOLMod models are detailed and complex, the process LEI used can be described simply as an iterative, sequential process:

- Step 1: Run GPCM with standard assumptions and data set provided by RBAC Associates. Turn off GPCM's auto-expand function for New England, to prevent the model from automatically adding pipeline capacity. Use our MECRA Baseline outlook pipeline capacity assumptions, as discussed above. Arrive a t gas price outlooks for Algonquin Citygate and receipt points Dawn, Niagara, Wright, and Mahwah.

- Step 2: Run POOMod with Algonquin prices generated by GPCM, to get gas burns and power prices.
- Step 3: Use the gas prices from Step 1 to calculate the MECRA Baseline outlook cost (price x quantity) of gas to residential, commercial, industrial sectors. Use the power prices and power consumption from Step 2 to calculate the MECRA Baseline outlook cost (price x quantity) of power. Make adjustments to account for retail hedges as noted previously in the text of this report.
- Step 4: Run GPCM for each ECRC. All assumptions are the same as in the Baseline outlook, except for the gas pipeline capacity that is represented by the ECRC.
- Step 5: Run POOLMod with the new Algonquin Citygate prices from each ECRC sensitivity case.
- Step 6: Use the gas prices from Step 4 to calculate the cost (price x quantity) of gas to residential, commercial, industrial sectors for each ECRC sensitivity. Use the power prices and power consumption from Step 5 to calculate the (price x quantity) of power for each ECRC sensitivity. Subtract MECRA Baseline outlook costs to arrive at annual benefits to consumers.
- Step 7: Use Algonquin Citygate prices and receipt point prices from Step 4 to calculate the resale value of capacity for each ECRC.

7.16 Uncertainties in baseline outlook for gas prices

A number of key uncertainties could impact the outlook for gas prices in the baseline. Key uncertainties include the timing of (non-ECRC) pipeline capacity additions that are contracted but not yet in service; the cost of developing and producing natural gas, especially Marcellus-area gas; the timing of new electric power transmission import capacity into New England; and changes to power market structure in New England. For example, if non-ECRC New England pipeline capacity expansions assumed in the baseline (TGP CT Expansion, AIM, and Atlantic Bridge non-ECRC) do not go forward, or are delayed, that would increase baseline gas prices and amplify the price-reducing impact of any of the ECRCs. If more pipeline capacity is built than in the baseline, then that would reduce baseline gas prices, and likely dampen the price-reducing impact of any of the ECRCs.

7.17 Other considerations: Peak day demand, peak hour demand, non-normal weather

Several aspects of gas demand are not captured in our model. These are peak day demand, peak hour demand, and abnormal weather. In the natural gas industry in New England, peak day and peak hour demand is usually not met by contracts for FT solely, but in conjunction with LNG peaking supplies. This tends to be more cost-effective.[65] In the long-term, weather can be assumed to be normal on average, so that the impact of actual weather on gas and power prices

[65] Northern Utilities. *2001 Integrated Resource Plan 2011: 5-Year Natural Gas Portfolio Plan*. December 30, 2011.

(and thus on the value of an ECRC) can be assumed to be neutral. Thus LEI feels that modeling monthly average gas demand under normal weather is appropriate for establishing a Baseline outlook and estimation of benefits of ECRCs. However, when supplies are tight, the option of having FT can be valuable, so the impact on the value of and ECRC is not symmetric: FT can be valuable in meeting demand peaks.

Power demand in the LEI simulation model POOLMod is hourly demand (for all 8760 hours in a year) based on normal weather. Because demand is based on normal weather, power prices do not reflect demand volatility or price volatility that would be driven by abnormal weather. Power demand changes hourly across the day, and power markets are structured to meet these changes. LEI's monthly average power prices reflect these hourly swings in demand and market-clearing prices. When peaking capacity is used to meet demand, LEI's energy prices reflect that (unlike in the gas price outlook).