Conservation Law Foundation (CLF) Responses to Wholesale Investigation (IR 15-124) Initial Staff Questions of July 2, 2015

August 3, 2015

Instructions for responses: Please e-mail responses in PDF format to alexander.speidel@puc.nh.gov; responses will be promptly posted to the NHPUC website here: http://puc.nh.gov/Electric/Investigation_into_Potential_Approaches_to_Mitigate_Wholesale_Electricity_Prices.html

1. In its Maine filing, CLF estimates that it will take three to four years from signing Precedent Agreements to gas flow for a "greenfield pipeline." How does CLF define "greenfield"? Would new construction in existing utility corridors be considered greenfield? If the answer to the previous question is yes, please provide all support for the "three to four years" estimate.

A. From CLF's perspective, a "greenfield" natural gas pipeline is a new natural gas pipeline, proposed to be sited in a location or right of way within which natural gas pipeline has not previously been located, permitted or analyzed for purposes of assessing the impacts of placing a natural gas pipeline in that location or site.

Support for the three to four years estimate for the time between signing Precedent Agreements to gas flow for a greenfield pipeline is supported by the expert testimony of Greg Lander, a gas markets expert with 34 years of experience related to natural gas supply, pipeline capacity, and gas pricing. In the Maine Public Utilities Commission proceeding 2014-00017, Mr. Lander served as an expert witness and testified that for a new, greenfield pipeline, "it will take between 3 and 4 years from the signing of Precedent Agreements to commencement of flow."[1] Mr. Lander again asserted this three to four year estimate at two additional times in the record.[2]

This three to four year timeline from signing Precedent Agreements to gas flow is corroborated by other past and ongoing natural gas pipeline projects. For example, in May 2012, Constitution Pipeline Company, LLC announced that it had executed Precedent Agreements with its customers,[3] and the company projects an in-service date of the second half of 2016.[4] Constitution's timeline amounts to approximately four years between Precedent Agreement signing and gas flow. Another pipeline, the Rockaway Lateral & Northeast Connector project, had Precedent Agreements signed in 2009 and then

[1] Direct Testimony of Greg Lander at 18, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #85).

[2] Transcript of Technical Conference at 176, 206-207, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #102).

[3] Pipeline and Gas Journal, "Constitution Pipeline Announces Customer Agreements" May 2012, Vol. 239 No. 5, accessed online http://www.pipelineandgasjournal.com/constitution-pipeline-announces-customer-agreements July 30, 2015.

[4] Constitution Pipeline.com, "Milestone Schedule" accessed online July 30, 2015.

an estimated in-service date of late 2014,[5] making for a slightly longer timeline of roughly five years. This duration is within the ballpark of the Mr. Lander's estimate.

2. What is CLF's estimate of the time from signing Precedent Agreements to gas flow for a lift and lay pipeline project? When the existing pipeline right of way is largely located in densely populated areas, could a lift and lay pipeline project be more costly and take longer to complete than a "greenfield" pipeline project?

A. Mr. Lander, gas market expert (see credentials above), testified that a typical timeline from signing Precedent Agreements to gas flow is two-and-a-half to three-years for an incremental or lift and lay project.[6] He opined: "A green fields [sic] is what had the longer timeframes on it of three to four or more years. And so I think an incremental - - we're seeing those being processed in a 30-month timeframe typically."[7] Mr. Lander later affirmed this estimate of 24 to 30 months later in his testimony.[8]

The gas infrastructure specialist, Greg Crisp of Spectra Energy, testified that the time from signing Precedent Agreements to gas flow is usually shorter for incremental (lift and lay) projects than for greenfield projects, which may be less efficient due to the larger number of stakeholders, interveners, and permits required for developing infrastructure on previously undeveloped land. He also cited efficiencies of lift and lay projects due to existing route, data, and analysis content that would have to be newly generated for a greenfield project.[9] He opined "the amount of impact, environmentally and stakeholder-wise, associated with an incremental expansion is lower than duplicating an existing facility over the same path. So you have less impact, overall, which makes the process go by faster and includes less risk."[10] Mr. Crisp is General Manager at Spectra Energy, where he oversees natural gas infrastructure development throughout the Northeast. He has been involved in over three billion dollars' worth of natural gas pipeline project expansions and has extensive knowledge of the field.

As to the second part of the question about pipelines in densely populated areas, Mr. Crisp testified that building pipeline in a congested area is not as easy as building pipeline in an area that is not

[5] Northeast Gas Association at 1, "Planned Enhancements, Northeast Natural Gas Pipeline Systems as of 8/27/14" accessed online http://www.northeastgas.org/pdf/system_enhance0814.pdf July 30, 2015.
[6] Transcript of Technical Conference at 176-177, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #102).
[7] *Id.*
[8] *Id.* at 208.
[9] Transcript of Technical Conference at 48-49, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #104).
[10] Transcript of Hearing on 07/31/2014 at 93-95, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #139).

densely populated.[11] Matthew O'Loughlin, Principal of the Brattle Group and on behalf of the Maine Office of the Public Advocate, testified similarly. Mr. O'Loughlin is a specialist in regulatory economics and valuation as applied to natural gas, oil pipeline, and electric power industries. He testified that, all else being equal, a greenfield project would take longer than an incremental project, even though an incremental project in a "densely populated" area or "where people have concerns" could also encounter delay.[12]

3. In its Maine filing, CLF projects that an increase in pipeline capacity will result in reduced "asset management" revenues for LDCs resulting in higher natural gas prices for consumers. Please quantify the natural gas price increase for LDC consumers from lost asset management revenues for each of the publicly proposed pipeline projects.

A. In the Maine PUC proceedings, Mr. Lander, expert on gas markets, testified that local distribution companies (LDCs) earn revenue by selling excess natural gas ("supplementals") on the secondary market,[13] and that, normally, this LDC revenue from asset management is shared with ratepayers, "often at ratios greater than 80%."[14] However, this revenue stream disappears when there is an over-supply of natural gas, as is the case when pipeline capacity rapidly increases, and results in increased prices to ratepayers.[15] Thus, the natural gas price increases that LDC ratepayers face from lost asset management revenue from the publicly proposed projects, AIM and TGP-CT, are based on the magnitude of the LDC arrangements, which are undisclosed.[16] During his testimony, Mr. Lander repeatedly pointed out the existence and importance of this cost born by ratepayers.[17]

[11] Transcript of Technical Conference at 31, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #104).
[12] Transcript of Hearing on 08/07/2014 at 148-149, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #142).
[13] Transcript of Hearing on 08/06/2014 at 150, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #143).
[14] Direct Testimony of Greg Lander at 25, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #85).
[15] *Id.*
[16] Transcript of Technical Conference on 07/17/2014 at 161-165, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #102).
[17] Direct Testimony of Greg Lander at 25, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #85); Transcript of Hearing on 08/06/2014 at 150-151, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #143);

Moreover, Mr. Lander provided documentation of these devaluations of the secondary market as a result of the Kern River and El Paso pipeline expansions.[18]

Likewise, Mr. Crisp, expert on natural gas infrastructure, testified that the increase in pipeline capacity "will contribute to a 35 percent basis reduction, translating into $655 million of annual savings for the region."[19] **If LDC asset management revenues are built on the sale of this excess gas that normally comprises the basis differential, the rate of reduction of the basis equals the rate of losses to ratepayers. Therefore, ratepayers could see losses of 35%.**

4. Page 2. Please identify the New Hampshire electric utilities that are major equity investors in new infrastructure projects and provide for each the project name and the equity interest.

A. Eversource Energy is a partner with Spectra Energy and National Grid in the Access Northeast natural gas pipeline project. Information regarding the details of its interest is best obtained directly from Eversource Energy. Eversource Energy also has an interest in the proposed Northern Pass electric transmission project. Specifically, the transmission lines and facilities located in New Hampshire for the proposed project would be owned by Northern Pass Transmission LLC—a New Hampshire limited liability company owned by Eversource Energy Transmission Ventures, LLC, which is a wholly owned subsidiary of Eversource Energy.

Liberty Utilities Corp. (Granite State Electric) d/b/a Liberty Utilities is a wholly owned subsidiary of Algonquin Power & Utilities Corp. (APUC) which, on November 24, 2014, announced plans to form "Northeast Expansion LLC" with Kinder Morgan to participate in the development of the Northeast Energy Direct natural gas pipeline project.[20]

In addition to New Hampshire electric utilities, the Commission and its Staff should remain sensitive to non-EDC stakeholders in this docket who may have sponsorship, affiliate or other financial interests in "solutions" to the "high price problem" identified in the Order of Notice, and should require that such interests be disclosed and managed in accordance with all applicable Commission rules. Such stakeholders include, e.g., Tennessee Gas Pipeline Company, LLC (Northeast Energy Direct natural gas pipeline project) , Spectra Energy (Access Northeast, Algonquin Incremental Expansion, Atlantic Bridge), and Portland Natural Gas Transmission System (future natural gas pipeline expansion, *see* PNGTS Initial Comments at 7).

5. Page 3. CLF states that it does not offer a solution. However, at page 12 it goes on to say that CLF "is working with a gas markets expert to develop a proposal for states to revise their policies related

[18] Oral Data Request Response of Greg Lander, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #82).

[19] Direct Testimony of Greg Crisp, Exhibit GNC-2 at 5, Public Utilities Commission Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901 (2014) (No. 2014-00071) (Item #82).

[20] *See* http://www.prnewswire.com/news-releases/algonquin-power--utilities-corp-to-partner-with-kinder-morgan-283776631.html.

to LDC on-system storage and increased use of LNG that will allow LDCs to design and sell gas products based upon enhanced utilization of this available gas capacity. Stored gas can serve to offset need at times of peak demand and thereby minimize the need for new gas pipeline capacity." Is this proposal expected to solve or contribute to solving the high winter period electricity price problem? If yes, please provide a detailed explanation of how it will lower winter electricity prices. If no, how is the proposal relevant to this investigation?

A. CLF is still in the process of finalizing the LNG storage proposal that it is working on with Greg Lander of Skipping Stone and expects to release the report in August and will supplement this response at that time.

The proposal is expected to solve or contribute to solving the high winter period electricity price problem by utilizing a combination of LNG import facility capacity and on-system LCD LNG storage facilities to effectively increase the system based load capacity during the winter peak periods. The effect of this increased deliverability or capacity is that LDC's will have capacity available at peak times for natural gas-fired electric generators either for secondary market purchase or through short-term contract sales to such generators.

The increased available supply on the secondary market will lower spot market gas prices paid by generators and any advance contract for such capacity should be at a price lower than the spot market. These reductions in the cost of gas supply for natural gas fired electric generators should translate into lower electricity prices for consumers.

New England has approximately 20 bcf of LNG storage on its pipeline system, between smaller facilities owned by LDCs (16 bcf) and larger storage at LNG import facilities. With adequate advance planning and scheduling, stored LNG, once vaporized, can serve to offset need at times of peak winter demand. This would both increase utilization of existing facilities and minimize the need for new gas pipeline capacity. Earlier this spring, GDF Suez, the owner of the Everett Distrigas facility, announced contracts to supply LDC storage totaling 9.5 bcf for the winter of 2015-2016, including a long-term contract with a major LDC for at least 3 bcf/year in subsequent winters through 2024.

LNG can be both a needle peak day deliverability supplement resource, and it can function as a combination base-load and peak day resource, provided advance planning, ship scheduling and vaporization off-take are effectuated.

Considering the very low load factor utilization of any new pipeline capacity proposal, and the resulting high effective per unit of use cost, LNG utilization through existing facilities not only can be a viable alternative but is likely to be far less expensive than new capacity and can be accomplished without having to make the 20 year commitment required by the PAs. One workable version of this method could include base loading a certain amount of LNG (both ship borne and satellite LDC) in the winter months in place of incremental pipeline capacity, scheduling refills of satellite facilities with trailer-borne LNG, and then because this partial winter period base-loading of back-hauled and on-system LNG would free up existing forward-haul pipeline capacity, the companies could then use that newly freed-up existing forward-haul capacity to meet daily variability in projected load (i.e., swinging

on both pipeline capacity as well as both remaining satellite and terminal (onshore and offshore) LNG deliverability).

The key to this alternative view of the use of ship- and trailer- borne LNG is a rethinking of how these resources are utilized. Rather than husbanding it for use on only the coldest high-demand days, you increase its utilization, treat it like a pipeline, and in the process free-up some existing pipeline capacity for swing, flexibility, reliable diversity, or even short-term capacity release. As a general planning principle, if fixed costs are required to be incurred, it is preferable to make them as small as possible and to build in future optionality rather than foreclose it. The Distrigas LNG facility in Everett, MA, has historically functioned both as a peaking and as a nearly baseload facility governed by bilateral contractual obligations, especially during the first 30 years of its existence (1974 to 2004).

6. Page 5. CLF reports that the "futures markets for wholesale electricity are predicting another moderately priced winter." Are wholesale electricity futures prices a good predictor of future wholesale electricity prices? If yes, please provide the studies on which the claim is based.

A. Response will be provided by CLF on August 4.

7. Page 5. Please provide the corresponding CME Group futures market prices as of June 1, 2013 and June 1, 2014 for the six months December 2013 to December 2014 and December 2014 to May 2015 respectively.

A. CLF does not have, or have access to, the requested information. CLF understands the Department may obtain such historical pricing information from CME Group through its subscription "DataMine" service (*see* http://www.cmegroup.com/market-data/datamine-historical-data/).

8. Page 5. CLF states that if the "future[s] prices remain steady through the fall when the EDCs make their winter energy purchases (or even drop on a potential expectation of warmer winter conditions than the past two winters), retail prices in effect for this coming winter will be far lower than this winter." Does it follow that if futures prices do not remain steady through the fall but actually increase due to changed expectations regarding weather and/or market conditions, retail prices this coming winter could be higher than this past winter? If your answer is no, please explain.

A. It does not necessarily follow that, if futures prices increase this fall due to changed expectations regarding weather and/or market conditions, retail prices this winter will be higher than last winter. It is reasonable to understand futures prices this fall to be an indicator of expected prices for this winter as the futures market relies on the experience of the prior winter to predict the upcoming winter, therefore significant changes in the futures prices before retail winter rates are set this year would appear unlikely.

9. Page 6. Did CLF conduct similar average bill analyses for New Hampshire commercial and industrial customers? If yes, please provide the results of that work.

A. CLF did not conduct similar average bill analyses for New Hampshire commercial and industrial customers but the results are similar: despite New Hampshire's relatively high volumetric

electricity prices, its average commercial and industrial monthly electric bills are among the lowest in the nation. According to the U.S. Energy Information Agency (*see* http://www.eia.gov/electricity/sales_revenue_price/), for 2013: the average commercial electric bill in New Hampshire was $167.33 lower than the national average and lower than 39 states and the District of Columbia (12th lowest nationwide); the average industrial electric bill in New Hampshire was $1,940.35 lower than the national average and lower than 32 states and the District of Columbia (19th lowest nationwide).

10. Page 8. CLF states that "neither new pipeline capacity nor proximity to Marcellus wellheads ensures protection from cold-weather price spikes." Assuming the receipt point for a new pipeline project is in the Marcellus Shale production area and the pipeline directly serves multiple New England gas-fired generators under firm transportation agreements, please explain why such generators would pay natural gas commodity prices that materially exceed the price of gas at trading hubs within the production area.

A. As winter 2015 pricing indicates, neither new pipeline capacity nor proximity to Marcellus wellheads necessarily ensures the absence of cold-weather price spikes because vaporized natural gas is a nationally traded commodity serving both thermal and power generation end-users that is subject to a wide range of factors influencing its price. As indicated in CLF's comments, PJM and NYISO often experienced winter 2015 price spikes at the same time and of the same magnitude as New England even though current pipeline infrastructure—like proposed new pipeline projects—has "receipt point[s] . . . in the Marcellus Shale production area and . . . directly serves multiple New England gas-fired generators under firm transportation agreements." Moreover, scarcity in regional winter pipeline capacity, and related high prices, need not translate into high local gas or electricity pricing with increased utilization of existing pipelines, east-west flows from Canada, and greater use of imported and stored LNG.

11. Page 9. CLF indicates that wholesale gas prices exhibited extreme volatility at Texas Eastern delivery points within the M-3 market zone during the winter of 2014/15. Does CLF agree that that volatility is the result of constraints on existing upstream pipelines delivering gas to the Texas Eastern M-3 market zone and that those constraints could be relieved through the expansion of those pipelines and/or the construction of new pipelines supplying the M-3 market zone? If CLF does not agree, what is CLF's opinion on the cause of the volatility and why would expansion of existing upstream pipelines and/or the construction of new pipelines not solve the problem?

A. No, or not primarily. CLF is asserting that New England's position "at the end of the pipe" (which is itself not accurate, since we also get pipeline delivery from the north) is not the cause of winter price spikes, because these other regions also experience parallel spikes during the winter. Rather, the comparison between the 2014 and 2015 winters, and between New England and PJM over both of those winters, show that interplay between the natural gas market and electric market, and specific methods for meeting peak generation demand and thermal sendout demand account for the winter price spikes. Better planning with respect to those factors served to ameliorate the winter price spike issue during the colder 2015 winter.

If CLF does not agree, what is CLF's opinion on the cause of the volatility and why would expansion of existing upstream pipelines and/or the construction of new pipelines not solve the problem?

As CLF states in its comments at page 10, there are serious uncertainties around the price effects of significant pipeline capacity buildout, particularly from the export market. Since the specific winter peak problems can be solved without such buildout, it would not be a prudent use of NH electric customer money to significantly expand pipeline capacity with the attendant price risks from export competition.

12. Page 9. Please explain why the extreme price volatility shown in the three NGI charts is "a strong indicator that more gas infrastructure does not necessarily lead to low or stable wholesale energy prices."

A. Please refer to response to Question 11.

13. Page 10. Please provide copies of the statements claiming "pipelines had been "full" during the winter of 2013-2014" and specify the pipelines to which the statements refer.

A. There are numerous examples of pipeline companies and energy market officials stating that pipelines had been "full" during the 2013-2014 winter. Examples include the Business Development Director for Kinder Morgan, Curtis Cole, stating in 2014 that the Tennessee Gas Pipeline was at "full capacity" and contributing to the high energy prices during the winter of 2013/2014,[21] and Gordon van Welie of ISO-NE stating that New England's pipelines were "reaching maximum capacity, especially during the winter months."[22]

14. Page 11-12. CLF asserts that world LNG prices in the range $6-7/MMBtu are "anticipated to direct more LNG shipments to U.S. ports, especially to receipt points with access to Northeast U.S. pricing during peak winter periods." If the price of LNG sold to gas-fired generators in New England is based not on the landed price of LNG but on the lower of the spot price of natural gas or the price of backup fuel oil, please explain how LNG an significantly ameliorate winter period wholesale electricity prices.

A. As was demonstrated during winter 2014-15, LNG shipments to New England can substantially affect winter period wholesale electricity prices in several ways. First, EDCs can directly enter into advance, short-term contracts with LNG companies at prices below the cost of spot price natural gas or backup fuel. Second, as discussed above, LDCs can contract for such LNG supplies and use them to supplement their existing on-system LNG storage supplies, thereby simultaneously increasing gas

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[21] Warner, Dan. MassLive "Many Tennessee Gas Pipeline questions still up in the air after Greenfield meeting with Kinder Morgan representatives" July 25, 2014 12:19pm and accessed online http://blog.masslive.com/breakingnews/print.html?entry=/2014/07/tennessee_gas_pipeline_expansi.html July 30, 2015.

[22] Northeast Forum on Regional Energy Solutions, "Remarks by Gordon van Welie, President & CEO, ISO New England" April 23, 2015. Accessed online http://www.iso-ne.com/static-assets/documents/2015/04/northeast_forum_on_regional_energy_solutions_van_welie_remarks_and_slides_04232015.pdf July 30, 2015.

supply at times of peak demand by "base-loading" their gas storage with LNG supplementation (by truck) and/or entering into advance, short-term contracts themselves to serve EDCs using this increased winter peak supply and deliverability.

15. Page 11. CLF asserts that a variety of market-based signals during 2014 led to an increase in LNG imports that lowered wholesale gas and electric prices during the winter of 2014/15. Does CLF contend that the 2014 market conditions that resulted in an increase in the availability of competitively priced LNG during the winter of 2014/15 will be repeated this year and beyond? If yes, please provide the basis for that argument.

A. Regarding global LNG market signals, see attached discovery response prepared by Gregory M. Lander for CLF in MA DPU docket 15-34, which was admitted into the record of the proceeding, discussing forward LNG price predictions. Regarding New England-specific energy market signals, the format of ISO-NE's Winter Reliability Program for the next three winters is not yet settled and is pending before FERC. To the extent that the final program approved by FERC incentivizes LNG utilization, as it did in 2014/15, the program will provide further market-based signals for imported LNG.

16. Page 12. CLF states that "current regulatory policies and requirements encourage LDCs to retain this stored gas all winter to ensure availability for heating customers." If CLF's proposal results in stored gas being used to supply peak demands in order to minimize the need for new gas pipeline capacity, please explain how the LDCs will be able to meet the objectives of the "current regulatory policies and requirements".

A. As discussed in CLF's response to question #5, CLF's proposal would utilize capacity releases from LNG import facilities through their interconnected pipeline system as well as releases from LDC LNG storage facilities at times of peak demand to meet system demand, including that of natural gas-fired electric generators.

The gas regulatory policies of some states create incentives for LDC's to limit (or disincentives to utilize) their use of stored natural gas (LNG) in order that the stored capacity is available in times of peak or extreme peak demand as a means of ensuring natural gas supply reliability. Under CLF's proposal, LDCs would enter into short-term winter peak period contracts for LNG from LNG import facilities. The LNG import facilities would, pursuant to these supply contracts, increase their truck-borne shipments of LNG to these LDC storage facilities to ensure that the supply of stored, on-system LNG supply is maintained and adequate for ensuring their reliability function.

17. Page 13. CLF states that "it is likely these projects [the AIM and TGP Ct expansion projects] will have some effect on wholesale electric markets and could achieve all or most of the objectives that special Commission action may target, without additional costs for electric customers." Does CLF contend that the effect of the referenced projects on wholesale electric markets will be temporary or permanent? If the answer is permanent, please provide all analyses that support that conclusion. Also, please describe the "effect" and provide an estimate of its magnitude.

A. It is CLF's position that these projects will have the effect of reducing gas and related electricity prices on at least a temporary basis. This position is supported by various studies including, most recently, a study performed for the ME PUC by London Economics, Inc.[23] The effect of these projects (and the market-based Atlantic Bridge project that is likely to come on line soon after these projects) should be to provide price relief while market adjustments such as Pay-for-Performance, gas-electric market coordination changes take effect and influence prices further, additional renewable, demand resource and storage resources expand and reduce the need for new gas infrastructure and supply.

18. Page 13. Regarding the Atlantic Bridge, Northeast Energy Direct, Access Northeast and Continent to Coast projects and the statement that some or all of these have sought, or may seek, investment from the states and electric customers, please specify for each project: (i) the form and amount of the investment sought from the states; and (ii) the form and amount of the investment sought from electric customers.

A. Each of the sponsors of these projects has been a participant in the ongoing Maine Public Utilities Commission proceeding by which the ME PUC is considering entering into a contract for capacity on each of these pipelines. Each of these project sponsors has submitted confidential proposals for Maine electric ratepayer investment in each of the above referenced pipelines. More informally, each of these companies/sponsors has submitted comments in this NH PUC proceeding as well as in the substantially similar pending Massachusetts Department of Public Utilities proceeding investigating state authority to enter into contracts for natural gas pipeline capacity and pass the costs of such contracts on to electric ratepayers. In each instance, the project sponsor comments have supported such state action and expressed the role that the sponsor's project could play in satisfying any state need for new pipeline capacity.

19. Page 14. Please explain why "it is an odd posture for stakeholders to be asked to propose and justify approaches that utilize efficiency and renewable resources."

A. The remainder of the paragraph to which you refer on Page 14 explains this statement. If the goal of this investigation is to reduce winter electricity prices (or electricity prices as a whole), it is curious to CLF why only a single potential solution is being examined in this docket and stakeholders are left to make an affirmative case for other options. As our comments note, the Commission itself has information from other current dockets and oversight activities regarding the cost suppressive benefits of energy efficiency and renewable energy sources, but has chosen not to integrate them into the potential solution set from this docket. In addition, CLF does not agree that this investigative effort can be divorced from the statutory obligations of the state's utilities to prioritize demand management over supply resources in long-range planning.

[23] https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=86937&CaseNumber=2014-00071.

20.	Page 15. CLF reports that wind energy "reduced wholesale electric prices by $26 million during one week of extremely cold weather in January 2014." Please provide the RENEW study on which this claim is based.

**A.	See attached PDF "Final Slides (20150701) RENEW" at 14.**

21.	Page 16. CLF asserts that "Commission action to further entrench natural gas with new infrastructure for fifty years or more with new pipeline infrastructure is emphatically not a positive step for achieving the needed reductions in carbon emissions from the electric sector to achieve New England and New Hampshire's climate goals." Does CLF dispute that displacing an existing generator that has a high CO2 emissions rate with a new combined cycle gas-fired generator that has a low CO2 emissions rate will lower the average system-wide emissions rate? If the answer is no, why is this not a positive step? If the answer is yes, please explain why.

**A.	Natural gas fired electricity generators deployed over the past fifteen years are responsible for substantial decreases in the emission of air pollutants associated with the region's energy supply, as they have replaced dirty, obsolete and uneconomic units. That transition occurred based on market forces that propelled the development of new natural gas generation. The combination of this build-out, an expanded renewables-based fleet and a proliferation of demand resources has resulted in the region's system-wide average greenhouse gas emissions from our electric generation sector being lower than the most efficient, new combined cycle natural gas fired generator. Consequently, the CO2 reduction benefits derived from a further expansion of even the most efficient natural gas generators will be at best modest and the opportunity for such savings limited.**

More importantly, the type of proposal under consideration by this Commission and other states in the region appears to involve a ratepayer-subsidized substantial build-out of new natural gas pipeline over the coming years. This potential oversupply of natural gas, as a means of affecting price reduction, is almost certain to result in significant development of additional new natural gas generation that might not have been economic in the absence of state intervention and that will have the effect of increasing the average system-wide emissions rate of CO2, particularly as it drives out alternative, cleaner forms of generation.