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May 29, 2015

Alexander Speidel
Staff Attorney/Hearings Examiner

Re: NH PUC, IR 15-124
NH PLAN Stakeholder comments per investigation into potential approaches to ameliorate adverse wholesale electric market conditions in New Hampshire

Dear Attorney Speidel, NH PUC Commission Staff and fellow stakeholders,

The New Hampshire Pipeline Awareness Network has a collective interest in stopping massive, greenfield, infrastructure overbuild associated with the Kinder Morgan/TGP Northeast Energy Direct (NED) pipeline project because it represents the worst choice for New Hampshire in terms of energy and infrastructure options. It is also the least likely alternative to result in the mitigation of price volatility and assured reliability in the electric market. Our group looks at all options in the interest of endorsing energy security for New Hampshire. We believe that unnecessary oversupply of natural gas has the ambition of being piped through, not to, New Hampshire. This particular pipeline project would actually come at the expense of energy security and at the peril of our domestic economy. No New England state would pay a higher price for this project's realization than New Hampshire while reaping the fewest benefits from its undertaking. For this reason, we welcome vigorous debate on smarter alternatives and viable options for ensuring price stability and supply reliability in our regional market.

A statement in the Order of Notice for this NH PUC docket claims that "during recent winters, significant constraints on natural gas resources have emerged in New England, despite abundant natural gas commodity production in the Mid-Atlantic States and elsewhere."[1] It goes on to quote the ISO-NE 2014 regional plan which states that "These constraints have led to extreme price volatility in gas markets in the winter months in our region, which, in turn, have resulted in sharply higher wholesale electricity prices."[2]

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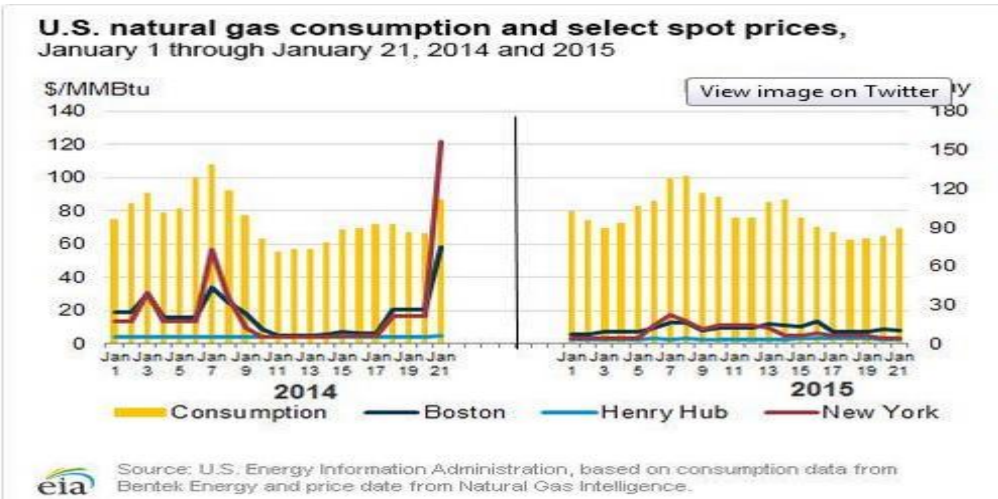
[1] See NH PUC IR 15-124 EDC Investigation into Potential Approaches to ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire, p. 2, available at: http://www.puc.nh.gov/Regulatory/Orders%20of%20Notice/041715onIR15-124%20Elec%20Distribution%20Utils.PDF

[2] See, e.g., ISO-NE 2014 Regional Plan, at pp. 124-147, available at: http://www.iso-ne.com/system-planning/system-plans-studies/rsp

The following chart was constructed from EIA data and posted on twitter by Christophe Courchesne, Senior Attorney at Conservation Law Foundation. The chart, and EIA data points from the corresponding footnote, reveal much about the state of the gas-electric market.



[3]

There is a lack of price volatility in 2015's gas-electric market despite having to endure record breaking cold snaps and average temperatures 26.5 degrees colder when contrasted with milder polar vortex winter temperatures of '13/'14. The wild spot market fluctuations of the prior year are in sharp contrast to the normalized prices of this year and seemingly dispute an industry meme about the correlation between pipeline constraints and spot prices. Clearly, pipeline "capacity" is not the only factor at play and has likely been overemphasized since we spent almost half as much for power this year as we did in the much milder previous year. In fact, only a small percentage of gas sold on the market in the '13/'14 polar vortex winter were based on sport market prices, yet there were enormous spikes for short periods in certain regions. While the price to consumers is almost always higher when generation resources are forced to procure fuel supplies at the last minute, the complexity of factors involved cannot be underestimated.

Data in the 2014 chart above also demonstrates that price volatility in Boston was mild in 2014 as compared to the New York market. This phenomenon was peculiar in so far as New York is known to have taken significant measures to ameliorate its supply constraints and yet still lay victim to enormous price spikes. Footnote references associated with the above chart further contrast the 2014 winter to 2015 by illustrating that a steady influx and resurgences of LNG imports in the 2015 winter season appears to have ameliorated much of the market volatility and supply reliability issues endured in the 2013-2014 winter season[4]. Many industry analysts have commented that New England "got lucky" with dropping oil prices and with ready suppliers of LNG. One significant factor that should be noted is that ISO-NE excluded LNG in the 2013-2014 Winter Reliability Program thinking that it would send the wrong

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[3] EIA Natural Gas data, 2014-2015, available at: http://www.eia.gov/naturalgas/weekly/archive/2015/01_22/#tabs-supply-1

[4] Deliveries of LNG take edge off regions gas supply, http://www.pressherald.com/2015/02/01/deliveries-of-liquefied-natural-gas-take-edge-off-regions-supply-gap/

signal to the market regarding the scarcity of natural gas so generators were not incented to make deals for this essential storage resource[5]. The 2013-2014 electrical market was therefore capped in New England by fuel assurance from expensive oil reserves and jet fuel peaker plants servicing peak demand on design days. According to GDF Suez, during '13/'14 Winter peak, LNG was $13/MMbtu as compared to the highest demanded spot price for piped natural gas which was upwards of $70/MMbtu. This resultant demonstrates that ISO-NE is not able to control price spikes from pipeline constraints in the market by subsidizing oil at the exclusion of LNG.

In 2015, better contractual planning in an effort to avoid the mistakes of 2014 and the serendipity of lower oil and LNG prices created the reliability necessary to weather one of the coldest winters on record in New England without any significant industry-predicted volatility in the electrical market. This resultant was not according to plan and pipeline constraints did not overwhelm market prices.[6] Residents and businesses spent $5.1B on electricity in the polar vortex winter while this past winter, at 25 degrees colder, was far cheaper, spending only $2.8B on power. In the absence of price volatility during peak Winter demand this year, one could suggest that in the near term, New England electric market is not suffering from a baseload issue, as has been suggested by many, but rather from a peaking gas supply issue.

It should also be noted that despite the Winter Reliability Program's (WRP) inclusion of LNG in its backup fuel incentives, the WRP cannot be given credit for this year's reliability. Even with favorable LNG import prices, $3/Dth secured by the program is not enough incentive for LNG operators to withhold LNG from the market, despite market signals and until the ISO calls for it. LNG providers y will likely always make more money selling when the market peaks. Out-of-market reliability must be offered out-of-market financial incentives which means paying an incentive price higher than the lowest fuel storage cost that can be sustained in the market that needs the reliability. NOTE: If exports become prominent for domestic gas market production, this could eventually mean having to adjust incentives to compete with world market gas prices. By incenting LNG providers to buy low off peak domestic LNG under the WRP at a fair recovery price and then regulating it at a fair price back into the electric market so that it is released in a manner that ensures fuel reliability during winter peak is needed for assurance. In fact, without proper incentives, LNG operators may not even store fuel to sell in New England and may choose more lucrative global markets. On the other hand, it may also be possible that LNG produced at Cove Point, Elba Island and in the Gulf of Mexico is heading the worldwide market into a glut of LNG for the next several years. Contracting for these U.S. LNG cargoes through import facilities in New England to support peak New England markets is likely a very sensible choice and may be cheaper than having to build new liquefiers or new pipeline infrastructure in New England. Also, ISO-NE should consider buying LNG and owning it by themselves in order to ensure reliability since the low global oil prices were responsible for providing the "luck" needed to bring LNG to New England this year.

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[5] , June 28, 2013, p.7. at: http://www.massplan.org/wordpress/wp-content/uploads/2014/10/ISO-NE-letter-to-FERC-6-2013.pdf

[6] http://www.reuters.com/article/2015/03/01/energy-natgas-newengland-idUSL1N0W125220150301

The spring season of 2015 has demonstrated that LNG has an important role to play in meeting peak demand for the 15-30 days out of the year when fuel adequacy is seasonably challenged. With incremental pipeline expansions providing even greater unused, off-peak capacity, this year's Spring-through-Fall seasons will represent a significant missed opportunity to convert through liquefaction the massive excess of natural gas supply that could have been stored in New England as LNG for future peak demand.[7] LDC's or the company's who hold their contracts who contract for specific capacity that is only fully utilized during peak demand would benefit financially from such utilization options. Liquefaction of domestic supply would serve as a hedge to diminish inherent price risks associated with exposure to the world LNG market. If LNG providers could be incented to overstock beyond their anticipated sell projections then a glut of LNG could saturate the market just in time to address the high demand that puts pressure on prices. LNG suppliers would still compete to sell their saturated supply but could receive payback at the end of peak season for oversupply risks associated with energy assurance. This might overburden rate payers during a period of adjustment that would improve through trial and error over succeeding winters.

The LNG storage market has an incredibly safe track record despite pockets of site opposition. Were there adequate storage via ISO-NE, utilities, or generators (through pay for performance), LNG could already be providing an excellent and reliable fuel backup for gas-fired generation in the next peak demand cycle and would be increasingly obtainable from cheap Marcellus shale prices if stored domestically.

Where pipeline expansions are largely designed to meet LDC heat load requirements, LNG provides the necessary flexibility to meet the needs of power generation and avoids the need for new pipeline capacity. Massive LNG import infrastructure has gone virtually untapped in recent years and utilization has declined precipitously since 2007[8]. Use of LNG as a peaking fuel is hindered not so much by global gas markets but by flawed domestic markets. According to the NH PUC, the recent declines in fuel oil and LNG prices are not expected to be sustainable against price indexes associated with Marcellus-area natural gas supply generation.[9] But, pipeline infrastructure on the order of magnitude of the NED project poses an excessive and expensive solution to the winter peaking delivery issues of the short and mid-term. LNG provides a cost effective alternative to a seasonal problem and avoids out-of-market solutions like the ISO-NE Winter '13/'14 Oil and Demand Response supplemental procurement program which only exacerbated market inefficiencies for which customers inevitably paid. When there is insufficient pipeline capacity, the market value of the pipeline rises to the cost of the alternative fuel for the market. LNG storage provides a reliability cap on both availability and price during winter peak demand and, with sufficient fuel assurances, sets a limit on anticipated volatility in the gas-electric market.

[7] http://www.nasdaq.com/article/natural-gas-futures-slump-on-modest-withdrawal-expectations-cm461126

[8] Northeast Gas Association, The Role of LNG in the Northeast Natural Gas (and Energy) Market, Import Facilities in New England, available at: http://www.northeastgas.org/about_lng.php

[9] Comment #6 from comments of the NH PUC to the F.E.R.C on docket's AD13-7-000 and AD14-8-000, available at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Wholesale%20Investigation%20Staff%20Letter%20to%20Interested%20Stakeholders.PDF

There is very little comparison between the cost of fixed assets associated with new pipeline transmission infrastructure versus the fixed costs associated with additional LNG storage (even though liquefaction adds a significant additional cost to domestic "full-cycle" storage solutions). While there are continuous flow benefits associated with supply from gas transmission infrastructure that cannot be matched by finite LNG storage, it is important to reflect upon the original NESCOE challenge that brought the NEPOOL incremental gas strategy (known as IGER) to the New England region in the first place. The problem to be resolved was and continues to be fuel reliability and price volatility during winter peak demand. Distrigas import facilities have already demonstrated their capacity to handle such demand.[10] Despite gradually declining LNG terminal imports over several years and despite the fact that the market has signaled its preference for excessive pipeline capacity to deliver cheap Marcellus shale, the lessons of the polar vortex have not been lost on some LDC's who have now reversed direction in favor for long term LNG import contracts.[11]

But, if we instead contrast Kinder Morgan's NED pipeline proposal against new LNG storage as a solution, we must begin by comparing the full pipeline cost; the combined supply and market path solution cost of the NED project, at approximately $5.5B against a comparable solution costs associated with development of new storage. To contrast pipeline infrastructure against a contrasting storage solution for resolving fuel assurance, we can begin by defining what an average winter peak shortfall would be. In this formulation we select a 6 bcf shortfall which, in New England, would represent 100 MMcf/d outflows over 60 days. NOTE: 2-3 LNG cargoes resolved peak demand this year where a tanker holding up to 130,000 cm of LNG regasified is about 2.8 bcf. If a conventional LNG storage tank were constructed at its maximum size of 120,000 cubic meters at a fixed cost of approximately $130M, the regasified storage of 3 equivalent, conventional, on-shore LNG storage tanks would cost on the order of $400M. This total demonstrates an enormous fixed cost savings of $5.1B from storage in contrast to the fixed costs associated with the NED project. Note that while a maximum-sized conventional storage tank could also be constructed in about a year less time than it would take to site and build the NED pipeline, new cryogenic tanks, known as C3T's, actually go up faster than conventional tanks, can hold more storage and have less labor costs associated with them.

If we now look at the variable cost of fuel beyond the fixed costs of infrastructure, the variable cost of fuel for 6 bcf of natural gas covering the winter peak shortfall, the following ballpark formulations are offered:

Pipeline fuel costs				
	Dth/d	$/Dth	Days	Annual Cost ($)
Supply Cost	100,000	$5	60	$30,000,000
Transport Cost	100,000	$2	365	$73,000,000
Total				$103,000,000
Annual Delivered Volume (Dth)	6,000,000			
$US/Dt	$7			

[10] http://www.nescoe.com/uploads/GDF-SUEZ_CommenstonIGER_30May2014.pdf
[11] http://www.lngglobal.com/latest/distrigas-to-fulfill-multiple-lng-contracts-with-gas-utilities-in-new-england-one-agreement-spans-10-years-of-supply.html

Domestic LNG fuel costs				
	Dth/d	$/Dth	Days	Annual Cost ($)
Supply Cost	100,000	$5	60	$30,000,000
Transport Cost	100,000	$0	365	$0
Liquefaction Cost	100,000	$5	60	$30,857,143
Total				$60,857, 143
Imported LNG fuel costs				
Annual Delivered Volume (Dth)	6,000,000	$10		$60,000,000

In the above approximations, LNG imports are added to consideration along with domestic LNG and pipelines. LNG imports come from established facilities where the same fixed construction costs of the other two options do not apply. Therefore, the variable costs are all that need to be considered to compare the imported LNG option to the two other formulations. Note in the chart that liquefaction costs are likely to be achievable domestically at prices less than $5/MMbtu but have been estimated here at the high end as a buffer. Also, World market LNG prices are currently below the $10/MMbtuprice estimated here bit since LNG prices fluctuate up or down and vary between destination points, a buffer has also been added here. This analysis will now consider these following 3 alternatives and their price estimates per MMbtu:

1. Building new pipeline,
2. Building domestic full-cycle storage (and assuming liquefaction over 7 low-demand months of the year), and
3. Using contracted LNG on the world market from existing terminals

The answer to which option resolves variable costs at the lowest price depends upon how often the pipeline would be fully utilized by the LDC's who own firm capacity when there is no excess capacity for generators. If the shortage period is less than 60 days per year then, by this calculation, contracting for gas at existing LNG import terminals provides the best variable costs. If domestic liquefaction can be produced at a cheaper price or if world prices for LNG are higher, domestic full-cycle LNG might also become the most attractive option for shortages of 60 days per year or less. Based on the numbers however, the shortage period would need to be greater than 151 days for new pipeline infrastructure to be demonstrated as the cheapest variable cost solution. If the number of shortage days fell between 60 and 151 days, then full-cycle terminals could be the best answer for the New England shortfall.

In ICF International's Phase II Final Report on the assessment of New England's Natural Gas Pipeline Capacity Report to Satisfy Short and Near-Term Electric Generation Needs, they assume the electric load forecast associated with their gas demand measurements could be off by as much as 50%. Under these very conservative profiles, the high gas demand forecast which assumes a large nuclear and coal-fired power outage to be simultaneously combined with high regional natural gas prices and are based on a mean daily temperatures averaged over the past 20 years, the number of days meeting supply deficits in New England were calculated as follows[12]:

Electric Sector Scenario	Duration of Deficit, in Days		
	Median	Minimum	Maximum
Phase I Reference	24	0	42
Phase I Repower	29	1	46
Phase II Retirement	34	5	51

As New England clearly falls within the 60 day shortfall window under all scenarios postulated by this study, LNG is given clear preference from the variable cost perspective. If fixed and variable costs are factored together, the preference for LNG over new pipeline becomes overwhelming.

As world energy markets continue to compete for supremacy, LNG imports are expected to be reasonably priced for winter reliability and fuel assurance in much of the foreseeable future.[13] "Half of the 41 fracking companies drilling for shale oil and gas in the U.S. will be dead or sold by year-end amid steep crude price declines, according to Bloomberg reports.[14] With world LNG prices tied to the price of oil, LNG imports can be expected to provide an adequate bridge to take New Hampshire from its current dependence on fossil fuel infrastructure into longer term commitments toward sustainable energy alternatives that start with energy efficiency and demand response. Projected annual saving of 1.5 to 2.0 percent are achievable in states with a decade or more experience with delivering EE programs. ICF International's Phase II Report on New England's natural gas pipeline capacity demonstrates that EE can reduce winter peak day gas consumption by as much as 550,000 Dth by 2019/20.[15] This is nearly half the gas contracted by Liberty Utilities to service New Hampshire cities and towns. Demand response and emerging battery storage can both dramatically reduce fuel assurance requirements with downward adjustments to peak demand and design day capacity requirements to which industry sets its supply formulas. Aggressive progress towards PV solar with battery backup for homes and municipalities, hydro, off-shore wind, refurbished or small scale nuclear are all becoming viable power alternatives and all have price suppression benefits on the wholesale electric market.[16] Geothermal and air sourced heat pumps can help dramatically with heat load.

The "renaissance" in which the gas industry claims we are amidst has caused a cessation of virtually all industry reference to natural gas as a bridge fuel. In fact, industry believes we need to build 450,000

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[12] Assessment of NE's NG Pipeline Capacity to satisfy Short and Near-term Electric Generation Needs: Phase II, p. 4, http://www.iso-ne.com/static-assets/documents/2014/11/final_icf_phii_gas_study_report_with_appendices_112014.pdf

[13] Deliveries of lioquefied natural gas take edge off region's supply gap, available at: http://www.pressherald.com/2015/02/01/deliveries-of-liquefied-natural-gas-take-edge-off-regions-supply-gap/

[14] http://www.presstv.ir/Detail/2015/04/23/407716/US-fracking-oil-companies

[15] Assessment of NE NG pipeline capacity to satisfy short and near term electric generation Needs: Phase II, p. 5, http://www.iso-ne.com/static-assets/documents/2014/11/final_icf_phii_gas_study_report_with_appendices_112014.pdf

[16] http://www.clf.org/blog/clean-energy-climate-change/renewable-energy-saves-money/

more miles of pipeline – a distance nearly to the moon and back.[17] New Hampshire's own PUC commissioner has endorsed a plan to take New England from its current reliability of 56% on this single fuel source of natural gas to 87% gas reliability in New England. The current sitting ISO-NE chairman and president has been on record as saying he would be happy with 100% dependence on natural gas. These market signals are extremely reckless and are not representative of the diversified energy portfolio both ISO-NE long term strategies and New Hampshire's 10-year energy strategy both say are essential to moving our energy economy forward.

Indeed, the gas industry is now seeking to solidify infrastructure underpinnings for the next major fossil fuel paradigm shift and will begin to target world markets that the gas industry has said are essential to their longer term viability and profitability. But, by extrapolation, this also indicates that selling only into domestic markets is unsustainable long term for this industry. Once global pressure is fully applied to the domestic market, while essential to the longevity of the gas fuel industry, will have devastating effects on the overall domestic economy. Providers in the gas sector will maintain tight, centralized control over energy production and distribution and only a very narrow sector of the U.S. economy will reap its profits or its trickle-down economic benefits.

What is important for our state, region and nation to add to this calculus is the fact that economists have demonstrated that each new infrastructure shift in the direction of a new fuel paradigm includes an adoption rate that takes at least 30 years of transition before adoption is complete. In U.S. history this same transitions has occurred moving from wood to coal, coal to oil and now oil to gas. As an economy dependent on averting impending climate catastrophe, our infrastructure transition to renewable fuel sources is now both economically feasible and economically necessary. Every dollar spent on massive gas infrastructure projects that keeps us dependent on out-of-state fossil fuels takes us backward into an old energy economy that will come at the expense of our needed transition into new, sustainable energy models. Natural gas provides little to no benefit in the fight against global warming.[18] Regarding adverse wholesale electric market prices, efficiency measures and renewable energy are known to save rate payers money, thereby stabilizing price volatility.[19] Renewable energy infrastructure also has the known effect of stabilizing gas prices by reducing demand.[20] It also promotes diversified and decentralized control over the energy economy which ultimately promotes local fuel sourcing, local energy governance, local jobs and local growth to wide sectors of the economy and better energy security provided through grid decentralization.

Minimizing our new investments in natural gas offsets more dollars toward sustainable infrastructure projects. Leveraging the enormous infrastructure we already have in LNG indeed provides an adequate and affordable bridge over to sustainable energy project conversions for New England's energy future. Much of this transition is already mandated by regional and state laws such as RPS , RGGI, the Massachusetts Global Warming Solutions Act and through clearly defined long term strategies including

[17] http://www.bloomberg.com/news/articles/2013-02-04/land-battles-rise-as-u-s-eyes-450-000-miles-of-new-pipe
[18] http://www.scientificamerican.com/article/natural-gas-offers-little-benefit-in-fight-against-global-warming/
[19] The ISO – and How Renewable Energy Can Save Rate Payers Money, http://www.clf.org/blog/clean-energy-climate-change/renewable-energy-saves-money/
[20] http://www.clf.org/blog/clean-energy-climate-change/renewable-energy-saves-money/

our own 10-year state energy strategy for New Hampshire[21]. While there is barely ever a mention of natural gas as a viable "bridge fuel" any longer, LNG indeed represents a most viable "bridge fuel" for the New England region. Storage can lead the way to energy efficiency, renewable energy, alternative fuels, a distributed grid and demand response solutions. New Hampshire's legal objective of achieving 25% RPS by 2025 is still in infant stages of development. It will not be unachievable if a 30 year gas revolution is allowed to take a firm foothold in our economy. In fact, if the full life cycle cost of fugitive methane was factored into the carbon price of natural gas, this emerging market would prove to be categorically unsustainable since from a Greenhouse Gas equivalency perspective, burning gas is only marginally better than its predecessors of coal and oil.[22] The human cost would be far worse.[23]

New England has safely relied upon LNG infrastructure to mitigate winter peak demand since the 1970's. LNG in New England has provided from 25% to over 40% of design day supply during winter peak for local gas utilities and has reached as high as 60%. LNG has supplied about 6% of New England's total annual gas supply, 25% of winter peak in 2010 and 20% of winter peak in 2013. Supporting this infrastructure to service future peak requirements is proven to be cost effective retrospectively. It should not be abandoned in the interest of building infrastructure designed to achieve nominal and temporary price gains from cheaper Marcellus shale gas. Oil and LNG are proving competitive with domestic shale gas in the current marketplace. When and if a significant price gap should occur in the future between domestic shale gas prices and LNG imports, there are at least three very significant reasons why building new pipeline infrastructure to service this domestic supply is a bad idea:

1. Encouraging massive gas infrastructure projects that oversupply the region and strand rate payer dollars on pipeline development will only encourage an export regime whose costs will be socialized and whose profits will be privatized. Moreover, the sale of gas exports will normalize the cost of domestic supply against world markets over time. This will not only diminish any benefits of utilizing our domestic supply for cheaper prices but will create competition over domestic resources that come at the expense of regional economies and the benefits they enjoy from domestic supply.
2. If gas infrastructure is overbuilt and becomes subject to exports, the region will not only be in competition with the rest of the world for winter storage for domestic shale and for fuel assurances, it will also diminish the viabililty of full-cycle storage as an alternative and leave no hedge on the cost of importing LNG to meet demand. A scenario in which we are heavily importing LNG at the same time that our domestic supply is being exported will also increase the overall cost of energy production, significantly increase greenhouse gas emissions and subject the global trade markets to highly speculative trading.

[21] www.**nh**.gov/oep/energy/programs/documents/energy-**strategy**.pdf
[22] http://phys.org/news/2014-05-methane-greenhouse-gas-expert.html
[23] http://www.greenbiz.com/article/governments-social-cost-carbon-could-be-increased?mkt_tok=3RkMMJWWfF9wsRogva%2FJZKXonjHpfsX87%2B4rXKGxlMI%2F0ER3fOvrPUfGjI4HScdiI%2BSLDwEYGJlv6SgFSLHEMa5qw7gMXRQ%3D

3. Increasing pipeline infrastructure will do nothing to enhance fuel assurance or ameliorate winter peak demand if power generators and EDC's do not sign up for firm transmission contracts. This drawback is further discussed in the following pages.

A more robust domestic LNG supply *can* provide fuel assurances, can ameliorate winter peak requirements and can mitigate price volatility and fluctuation. Having two sources for acquiring LNG supply, both the traditional use of import facilities and the additional use of larger scale liquefaction and storage (known as "full-cycle" storage) would provide an additional hedge on the price paid for LNG and would avoid massive pipeline infrastructure projects at a fraction of the cost. New England already has 46 customer-owned surface LNG storage tanks providing as much as 16.3 bcf, not including the outlay from Distrigas in Everett, MA. But, unlike the rest of the country, only 50 MMcf/d of this supply has liquefaction capacity to take advantage of domestic pricing. In contrast, the entire U.S. possesses 96 LNG storage facilities connected to the pipeline grid, 57 of which have liquefaction capacity. New England is unique from the rest of the U.S. in the sense that so much of its LNG storage is tied to imports, traditionally provided by the Distrigas hub, rather as a dependency on full-cycle storage like the rest of the country served by gas.

NH Plan questions the ISO-NE claim that "record high electricity prices of the past several winters were the result of pipeline constraints driven by insufficient investment in gas infrastructure to supply the increased demand for gas for electricity generation". [24] One important distinction needs to be made between lack of "physical pipeline capacity" versus lack of "available contracted capacity". This distinction is hidden from most resource reports in which available capacity is assumed to be physical capacity. In the New England region, our pipeline constraints are not due to physical capacity constraints. They are due to contractual constraints. In ICF International's "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near Term Electric Generation Needs: Phase II", information is provided about natural gas supply capacities in terms of their contracted levels, not their physical capacity. This leads the reader to believe that pipelines are running at capacity and that the only viable solution is more pipeline. In the following diagram, I have taken Exhibit 2-3 from the report and overlaid additional observations (in red) that I will proceed to explain[i]:

[24] Comment #4 from comments of the NH PUC to the F.E.R.C on docket's AD13-7-000 and AD14-8-000, available at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Wholesale%20Investigation%20Staff%20Letter%20to%20Interested%20Stakeholders.PDF

Exhibit 2-3. Phase II Assumptions for New England Natural Gas Supply Capabilities, 1000s Dth per Day

Total Projected Pipeline Capacity		2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forward Haul Pipeline Capacity										
Algonquin Gas Transmission (AGT).	1.400	1,118	1,118	1,118	1,118	1,118	1,568	1,568	1,568	1,568
Iroquois Gas Transmission System (IGTS).	1.100	228	228	228	228	228	228	228	228	228
Tennessee Gas Pipeline (TGP).	2.000	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291
Portland Natural Gas Transmission System (PNGTS).	249	249	249	249	249	249	249	249	249	249
Pipeline Capacity Partly Dependent on LNG Supplies										
Maritimes & Northeast Pipeline (M&N).	833	833	833	833	833	833	833	833	833	833
Subtotal	**5982**	**3,719**	**3,719**	**3,719**	**3,719**	**3,719**	**4,169**	**4,169**	**4,169**	**4,169**
Peak Shaving Capacity										
LNG Peakshaving	36.600	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
Propane-Air	137	137	137	137	137	137	137	137	137	137
Subtotal	**36737**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**
Direct LNG Import Capability										
Everett Distrigas Facility	715	715	715	715	715	715	715	715	715	715
Northeast Gateway (Received 1 bcf this year)	800	0	0	0	0	0	0	0	0	0
Neptune (Starting again In 2018)	400	0	0	0	0	0	0	0	0	0
Subtotal	**1515**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**
Total Assumed Supply Capability Available on a Winter Design Day		**5,890**	**5,890**	**5,890**	**5,890**	**5,890**	**6,340**	**6,340**	**6,340**	**6,340**
Total New England Capacity:	8.953									
Total Assumed Supply Capability Available on a Summer Peak Day (excludes Peak Shaving)		**4,434**	**4,434**	**4,434**	**4,434**	**4,434**	**4,884**	**4,884**	**4,884**	**4,884**

As can be observed from the numbers, physical pipeline capacity[25] is not actually constrained in New England's natural gas supply nor is it expected to be for the projected future. Note that on the Iroquois Gas Transmission System (IGTS) much of the potential flow to New England is captured upstream by the Mid-Atlantic states where demand for gas and its price points tend to be higher. Note also that the variation between subscribed and physical capacity suggests that adjustments made upstream from New England could have a profound effect on potential flow to our region. Spectra's recent New York-New Jersey expansion projects, for instance, cause gas flow to be displaced from New England to New York on the Iroquois system but also added significant potential for New York-contracted capacity to flow to New England anchor shippers in the future. Expiring contracts in the mid-Atlantic could free up as much as 700 Mcf/d by mid-2015 -- upward bounds on such contracts could add as much as 1.5 bcf/d to New England's supply with some adjustment to infrastructure at certain points along existing lines.

Additional things to note:

1. Capacity on the Algonquin Gas Transmission (AGT) system at the top of the chart changes to 1568 MMcf/d by the end of 2016 because of new online capacity from the Spectra AIM (380 MMcf) and the TGP CT Expansion (70 MMcf). Both are expected to come online that year and by themselves are predicted to cover based load demand projections for New England for as much as 10 years afterward. It is important to keep in mind that New England's power requirements have dropped on average by 1% every year since 2005 and U.S. Electricity Demand has been flat since 2007.[26]
2. LNG peak shaving is provided by 46 customer-owned surface LNG storage tanks in New England which could be expanded. Domestic liquefaction would also allow domestic gas supply to be

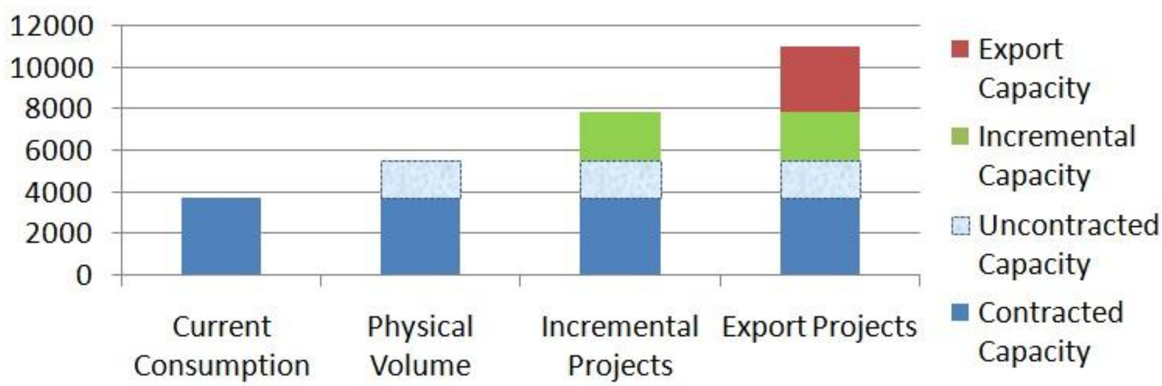
[25] Black & Veatch NESCOE study on "Natural Gas Infratructure and Electric Generation: A Review of Issues Facing New England", p. 8-9, http://www.nescoe.com/uploads/Phase_I_Report_12-17-2012_Final.pdf

[26] http://spectrum.ieee.org/energywise/energy/environment/us-electricity-demand-flat-since-2007/?utm_source=energywise&utm_medium=email&utm_campaign=021115

stored locally for peak demand without having to import LNG and as a hedge against fluctuations in import prices.

3. 2015 was the first time Northeast Gateway has supplied East to West flows of gas to New England since 2010. This is a gravely under-utilized facility available to New England to absorb peak demand requirements. Due to under-utilization, the Neptune facility did not renew its licenses but is eligible to restart delivery in 2018 if there is demand.

In addition to removing contractual constraints on existing physical capacity as a means of expanding service to New Engand, there are many ongoing incremental gas projects projected to come online for New England in the next several years that will expand available supply well beyond New England's current and future demand projections. The following chart shows some of the current project proposals and their potential effect on gas supply to the region (shown in green).



Incremental Existing ROW projects	Capacity	Existing Right of Way Project?
Spectra Algonquin AIM + TGP CT (2016)	0.450 bcf	Yes
Portland C2C Expansion (2016)	0.182 bcf	Yes, could be widened
Constitution Pipeline	0.6 bcf	Yes, + 600 MMcf w/compressors
Algonquin Atlantic Bridge	0.6 bcf	Yes
Spectra Access NE	.2-1.0 bcf	Yes (Export capacity)
Kinder Morgan/TGP Northeast Energy Direct (NED)	1.2-2.2 bcf	No, "greenfield" (Export capacity)

In the above chart, a number of things should be noted:

1. Contract capacity in the range of 3.8 bcf/d is essentially "design day" capacity for peak demand in all of New England. Average daily consumption is dramatically lower than design day requirements.
2. By including only the physical capacity of the existing lines and the incremental capacity of existing project proposals, New England's design day gas capacity more than doubles. Additional incremental projects are potentially available, such as on the Constitution pipeline that could double its flow of direct Marcellus supply with additional compressors. Also, the

Portland Natural Gas Transmission System (PNGTS) expansion is capable of taking supplies from the Continent to Coast (C2C) project[27] or from the Iroquois South-to-North (SoNo) Project for additional regional supply.[28]

3. When we compound New England capacity with pipeline infrastructure added by Kinder Morgan's Northeast Energy Direct (NED) project and Spectra's Access Northeast project, the underlying objective to overbuild pipeline capacity through New England becomes quite evident. For this reason, the chart depicts (in red) these projects as export bound capacity. While the NED project must be backed by anchor shippers and the Access Northest project by reforms likely to include electrical tariffs, both projects will likely contain stranded costs associated with their massive size. Until such time that export contracts become viable for consideration in targeted world market destinations, these stranded costs will be the burden of rate payers with no domestic benefit. After export contracts are secured, those stranded costs will then come at further expense to rate payers who will now pay higher prices for gas and electricity with the added burden of having to fund export profits at no additional rate payer benefit. Note that in a recent Washington, D.C. meeting, the ISO-NE CEO admitted that the point of the N.E. governor's plan is to "overbuild" gas pipeline. But as Vermont Governor Shumlin pointed out, this overinvestment risk puts "huge stranded costs" on customers for decades to come.[29]

While much of the above information does not directly correlate to the question of how fuel assurance is provided to the wholesale electric market, it is important to dispel the notion that price spikes in the wholesale electric market and fuel assurance for generators is somehow tied directly to the issue of pipeline constraints. The commissioner of the NH PUC has advocated for more natural gas to be brought to the region in light of the cost of constraints to electric rate payers in New England. In reality, the problem of fuel assurance for the power market is far more complicated and the availability of more gas to the region does *nothing* to resolve fuel reliability during the period in which it matters most namely, during winter peak demand.

New England is more than 50% dependent on natural gas for its power demand and yet power generators generally do not contract for firm pipeline capacity since the market structure does not provide incentive/signals. However, in order for a Certificate of Public Convenience and Necessity to be granted for new pipeline using traditional certification methods such as those being used to approve the NED project, a show of "need" in the form of binding precedent agreements with parties who want transportation capacity must be demonstrated. Firm contractual commitments are generally held over 20 years by Local Distribution Companies (LDC's) and must be sized, by regulation, to no more than the current design day bracketed by load forecasts. Moreover, pipeline companies are at high risk if they incur unsubscribed capacity because their ROI rates are calculated with the assumption that the pipeline is 100% sold. Generally, there is very little unsubscribed capacity on new or existing pipelines.

[27] http://www.nhbr.com/July-12-2013/Natural-gas-pipeline-plans-bring-opportunities
[28] http://energyinterdependencyblog.com/iroquois-south-to-north-project-sono-another-example-of-shale-gas-production-reversing-historical-gas-flows/
[29] http://www.clf.org/blog/clean-energy-climate-change/governors-infrastructure-plan/

LDC's who hold firm capacity on transmission lines will generally release it onto the secondary market where it is available to generators, except on the coldest days of the year when the combination of heat load and power demand are simultaneously peaked. On these days, LDC's take all of their subscribed capacity for themselves leaving little to no unsubscribed capacity for generators. As gas demand has grown, mostly from new gas-fired generators, pipeline operators have been operating their systems at increasingly high utilization rates and have resulted in constrained capacity, irrespective of physical capacity. These constrains make the practice of "just-in-time" gas procurement increasingly more challenging. But, even though the electric market is constrained during this time, utilities and generators are still very unlikely to sign up for anything other than interruptible contract services which would cease their delivery during peak demand. Only when rising price hikes incent enough gas-electric buyers to purchase capacity and only if a reprieve in design day conditions frees up an amount of short term supply that can be bought will a marketer be able to obtain and sign for short-term flow. The marketer will only risk such contracts if they believe they can capture the spread between their contracted price and predictably higher prices on the market in which the contracted gas will be resold. At this point, price escalation resulting from high demand over short supply in combination with speculative purchasing behavior in search of future gas price rewards commences and price volatility ensues.

New pipelines can only solve the above-mentioned problems if they are allowed to be overbuilt. As mentioned, overbuild usually represents high risk and a reduced return on investment to pipeline owners. And, without the promise of selling capacity to additional subscribers, such as export contracts, pipeline companies would be reluctant to leave unsubscribed capacity available in the interim to also power generators during peak demand since pipelines want contracts with continuous flow and paid subscriptions whether or not the gas is used. Even if pipeline companies were willing to accept higher risk from power market investors, it would be highly irregular and unfair practice to bury such capacity costs in the construction of new pipeline where ratepayers would be obligated to pick up the burden of investments that are potentially stranded for 8-10 months of the year. The idea that we would proceed with continuous-flow new pipeline construction in the hopes of a small stranded-cost gap between physical and subscribed pipe capacity makes little sense. The temporary fuel assurance this would provide to the electric market would only last until LDC's expand their territory and buy up unsubscribed capacity with new contracts. In this cyclical madness, there would be continuous and endless justification for new pipeline whenever subscribed capacity hits physical limits over time or whenever physical limits become constrained by oversubscription in upstream markets (as is the current case). This persistent squeeze on fuel assurance and gas price stability is the gas industry's recipe for the 30 year paradigm shift toward natural gas adoption they desire at the expense of rational and essential energy decisions for our future.

The urgency to resolve such matters have raised testimony such as the following from ISO-NE's CEO and President, Gordon van Welie in the aftermath of the polar vortex winter in New England[30]:

[30] http://www.nei.org/Issues-Policy/Policy-Resources/Testimony/Testimony-of-Gordon-Van-Welie,-President-and-CEO,?feed=Testimony

> The region's reliance on generation with "just in time" interruptible fuel-delivery arrangements has created operational challenges that are escalating rapidly. The region experienced significant operational challenges in January and February when a significant number of generators were unavailable due to uncertain fuel supplies or storm-related outages. We are seeing this more frequently and it is unsustainable.

The above statement demonstrates the ISO chairman's clear understanding of the problem. But for as long as the "solution" is to sign new anchor shippers to precedent agreements for heat load, we have come no closer to solving the problem. As long as the "solution" is to draw direct correlations between pipeline constraints and electric prices, we will get new infrastructure but only short-lived solutions, if any. Under the Federal Energy Regulatory Commission's traditional regimen for pipeline approvals, new pipelines will also begin to experience capacity constraints in the same way as old pipelines and a new supply and demand cycle for new pipeline infrastructure will begin all over again

System regulators, pipeline owners and legislatures in New England are now seeking to modify rules that govern electric utilities in each state to allow them to hold capacity on pipelines and to pass these costs along to electric rate payers. Assuming that gas-electric generators are setting the electric market clearing price, electric utilities who buy their power each day through ISO-NE at the market clearing price would now be able to buy kilowatts at a lower price while simultaneously bearing the cost of purchasing the capacity that has lowered their own costs.

To be clear, contracts of the above nature that are being proposed are currently expected to be negotiated between utilities and generators along the "Access Northeast" project of Spectra's Algonquin Transmission System. The competing Kinder Morgan NED project is expected to utilize the traditional model of signing anchor shippers for heat load which will do nothing to solve the root problems of fuel assurance in the wholesale electric market. Because of the electric market design, electric generators will not sign up for pipeline capacity under the NED project model. Generators cannot afford to pay for firm capacity because they would be paying for their subscription whether they run or not. Generators cannot bear this level of fixed cost for capacity and still be profitable.

The question to the NH PUC comes down to a matter of whether it will allow electric utilities, the benefactors of potentially lower electric prices, to also recover the cost of fuel assurance they bear on behalf of generators who cannot typically sign up individually for capacity, especially in the current market where electric utilities and power generators are in the process of being decoupled. Generators would not sign up in a market where new pipeline capacity was available anyway because with the extra capacity, if the NH PUC enabled fuel assurance cost recovery, would also cause the market clearing price to go down thus cutting into the generator's profit margin.

It has yet to be demonstrated whether rule changes will ultimately encourage the market in time to address real-time and future fuel assurance requirements. Non-power customers demonstrate the value of fuel assurance to them by securing firm capacity that avoids service interruption potential. New reforms must demonstrate similar incentives can exist for utilities on behalf of generators as

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currently exist for LDC's. Spectra's Access/NE project has at least developed partnerships with EDC's and services 60% of all the New England power plants because they reside along the Algonquin market path. In terms of having a chance to resolve fuel assurance in the wholesale electric market, Access/NE at least has the potential to provide benefit to the market by virtue of such arrangements assuming results of this docket are successful at providing the appropriate signals to the market. The Kinder Morgan NED projects shows no such promise of providing structural solutions to fuel assurance in the wholesale electric market nor to gas price volatility during high demand and constrained fuel.

As pointed out by this NH PUC investigation into this issue, generators have a responsibility to secure advance arrangements commensurate with their performance obligations or to fully understand the financial risks of not doing so.[31] Non-performance penalties associated with Pay for Performance programs may create market incentives for generators to procure fuel so they are ready for dispatch when asked. But if the proper opportunities do not exist to enable cost recovery or if the fixed costs associated with procurement are not matched by favorable opportunities to generate power, many power generators may find themselves forced out of business by rigid requirements and inconsistent opportunity to generate revenue. ISO-NE and New Hampshire should ensure that there are comparable incentive opportunities provided to sustainable energy markets so gas generation also include long term market signals that energy replacement options should also come from competitive and available offerings of renewable energy.. Placing the burden of gas procurement on regulated utilities may be more manageable and less burdensome to the competitive power market overall but utilities are assumed to require some level of advanced arrangement with producers in order to know in advance what generators will be in the bid stack and will need fuel assurances. This may be very difficult to predict and will need to be reactive to changes in the market. If firm capacity procurement cannot be made reasonably predictable in the competitive power market, then again we could see stranded costs on the wholesale market and higher wholesale prices related to having to compensate unused procurement (assuming guarantees are backed by tariffs on rate payers).

If it remains infeasible to expect both operators of generation capacity or utilities to invest in firm fuel transportation arrangements, then constraints on subscribed capacity and the price volatilities of the spot market will continue to plague the gas-electric market. Recent improvements in intraday scheduling may improve market coordination but may also continue to see fixed flow requirements forced by gas suppliers. If utilities are willing to secure short term contracts, they may be forced to decide which generators are cycled off and which are forced to run during uneconomic periods in order to avoid operational penalties and in order to ensure their availability when called upon by ISO. If a utility happened to shut down a particular generator that was dependent on its gas supply but that same generator was then unready to perform later when requested by ISO, who would be responsible for paying the non-performance penalty? Would the utility be disqualified from receiving make-whole

[31] See NH PUC IR 15-124 EDC Investigation into Potential Approaches to ameliorate Advers wholesale Electricity Market Coneitions in New Hampshire, available at: http://www.puc.nh.gov/Regulatory/Orders%20of%20Notice/041715onIR15-124%20Elec%20Distribution%20Utils.PDF

payments when generators run during uneconomic periods? Will such manipulations of the market artificially raise market prices for electricity and place all the risk of poor planning on the backs of rate payers who lack both transparency and involvement in the underlying operational mechanisms?

Conclusion

If we are going to continually size pipeline infrastructure to design day capacity as though it were the only resource available to the energy market or if we are going to purposely overbuild pipeline infrastructure to the region to bolster exports, we should at least acknowledge that in New England, design day capacity will always be provisioned to serve a very small number of days out of an entire year and that inherent capacity constraints during extreme demand will never be fully resolved in New England by forcing the entire gas and electric market to procure firm contracts. Heat load obligations will always need priority and the closest we will ever get to normalization of Winter peak gas demand is with "reasonable", not "perfect" costs per BTU for fuel supply from options other than pipelines or from fuel sources other than gas. In the New England market, LNG from existing terminals or from domestic storage of cheap Marcellus provides the best hedge against instability in the gas market and its inherent price volatility.

It is also fair to say that for as long as design day capacity or oversupplies of natural gas are allowed to enter New England, we will be faced with off-season abundance that will cost additional energy and additional gas flow management in order to become better utilized for other purposes, i.e., either to flow South to off-peak demand destinations elsewhere, or North, South and East to export terminals where domestic shale price advantages will become upwardly normalized by global markets, or to off-peak liquefaction plants for LNG storage generation and fuel assurance in the following year. In the interest of New England and the entire U.S. economy, ISO's/RTO's, government and suppliers need to ensure that incentives exists to take care of the domestic market first and should avoid any incentive for highly speculative import and export regimes to control and dominate world trade, create economic bubbles, promote irresponsible energy use and exacerbated global warming hazards associated with exports and fugitive gas that starts at fracked fields and increases through the distribution system and onto the burn tip. The further emergence of a 30-year paradigm shift in which gas trade markets are allowed to dominate our domestic and worldwide energy regimes becomes the same "game over" James Hansen warned of over the proliferation of tar sands oil development only by a different means.

The efforts of ISO-NE and NH PUC's participation therein to find the proper market conditions to encourage fuel assurance and electric price stability are to be applauded. NHPlan's estimation is that such efforts should be supplemented by encouraging complementary energy options in the market place. Despite a cursory glance that seemingly connects overcapacity of pipeline infrastructure to fuel assurance, the opposite is in fact true. For very complicated reasons investigated in this stakeholder commentary, the "bridge fuel" to New England's energy independence, energy security and energy future is not natural gas but liquid natural gas. While it is critical to get aspects of the IR15-124 docket precisely correct for smooth operation under our current energy paradigm, it is more important to ensure it functions with the proper incentives to encourage healthy energy markets for both the short and mid-term. It is even more essential that we not belabor embarking on an aggressive path toward short, mid and long term market reform starting with efficiency and progressing toward decentralized and sustainable energy alternatives. ISO-NE, NH PUC, federal regulators, law makers and members of the power and heat source industries should work as hard or harder at getting tariffs and tax subsidies properly appropriated for the development of renewable and non-climate crisis producing energy, grid stability, conservation and other efficiencies as they are doing to resolve current reliability needs. Many more problems associated with our dangerous and dying fossil fuel production could be ameliorated while local and domestic economies were strengthened if we focused more on energy diversity and decentralized control over the means of energy production and over the sustainable requirements of our long term infrastructure needs.

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[i] ICF International's "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near Term Electric Generation Needs: Phase II", p. 12, http://www.iso-ne.com/static-assets/documents/2014/11/final_icf_phii_gas_study_report_with_appendices_112014.pdf