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June 15, 2015

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: D.P.U. 15-37
Investigation by the Department of Public Utilities into the Means by which New Natural Gas Delivery Capacity may be added to the New England Market

Dear Secretary Marini:

Enclosed for filing in the captioned matter please find the Attorney General's *Initial Comments*. Please feel free to contact me if you have any questions. Thank you for your attention to this matter.

Sincerely,

/s/ Christina H. Belew

Christina H. Belew
Assistant Attorney General

Encl.

cc: David Gold, Hearing Officer
Service List, D.P.U. 15-37

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities into the Means by which New Natural Gas Delivery Capacity may be added to the New England Market

D.P.U. 15-37

INITIAL COMMENTS OF THE MASSACHUSETTS ATTORNEY GENERAL

Respectfully Submitted,

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DEPARTMENT OF PUBLIC UTILITIES

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INITIAL COMMENTS OF THE MASSACHUSETTS ATTORNEY GENERAL[1]

On April 2, 2015, the Massachusetts Department of Energy Resources ("DOER") filed a petition with the Department of Public Utilities (the "Department") requesting an investigation into the means by which new natural gas delivery capacity may be added to the New England market, including actions to be taken by the Massachusetts electric distribution companies ("EDCs"). In its petition, DOER makes three basic assumptions: (1) gas pipeline capacity constraints are causing unreasonably high winter electricity prices; (2) this problem requires an out-of-market, state sanctioned solution; and (3) that solution is for the Department to authorize EDCs to purchase gas pipeline capacity and to recover related costs from customers.

Before authorizing an out-of-market, experimental solution that subjects EDC customers to the risks of a large infrastructure investment, the Department should carefully analyze each of these assumptions. Specifically, the Department should:

- Undertake a full and careful analyses of the causes of high winter electricity prices and the need for potential solutions;
- Rigorously study the economics of new gas capacity and the full range of available options for addressing any winter pricing problem, including options that can reduce natural gas demand as well as options that can augment natural gas supply;

[1] For purposes of preparing its comments, the AGO engaged The Brattle Group to provide expert consulting.

- Determine, based on consistently applied economic metrics, which combination of legally available options, including market solutions, most cost effectively addresses the need while maintaining system reliability and meeting climate and other environmental requirements.

Only if, after performing this study, the Department determines, based on the study's results, that the Commonwealth should sanction the out-of-market procurement of additional gas pipeline capacity, and only if the Department finds that it has the authority to implement the DOER's proposed plan, then the Department should ensure (1) a competitive, transparent procurement process that avoids conflicts of interest; and (2) the fair management of any procured capacity that achieves the Department's stated goals for the benefit of ratepayers.

I. BACKGROUND

The primary impetus for this proceeding is the recent jump in winter retail electricity rates.[2] Electricity prices in ISO-New England depend predominately on the marginal cost of production, which reflects the efficiency and fuel price of the marginal (highest variable cost) electricity generator needed to meet electricity demand. In most hours, the marginal generators in New England are fueled by natural gas, and electricity prices during these hours are directly impacted by the price of natural gas paid by the electric generators. Thus, electricity prices in New England tend to increase when natural gas prices spike. The resulting volatility in regional wholesale electricity prices during the winter has caused an increase in the cost of retail electricity supply that typically must be procured and purchased by energy suppliers six months in advance.

[2] For example, one EDC's basic (default) residential supply charges rose from 7 cents/kWh for the 2012/13 winter rate season (Nov-April) to 10 cents/kWh in winter 2013/14, to 16 cents/kWh in the most recent winter. For reference, these supply rates are on top of base retail service rates of about 8 cents/kWh for transmission, distribution, and other charges. *See* https://www.nationalgridus.com/masselectric/home/rates/4_res.asp and https://www.nationalgridus.com/masselectric/non_html/MA_Residential_Table.pdf.

Natural gas prices spike in New England on a few dozen days during the winter when the weather is particularly cold.[3] During cold periods, the natural gas pipelines coming into New England become highly utilized by the gas local distribution companies ("LDCs") that use their contracted interstate pipeline capacity at high or maximum levels to serve their firm sales customers' space-heating needs. Because they generally do not hold firm rights to pipeline capacity, electric generators pay higher prices during these cold snaps for gas pipeline capacity. If available pipeline gas supply is insufficient to meet New England electricity demand, some electricity generators must use alternative fuels, such as oil or liquefied natural gas ("LNG"), which are typically more expensive than domestic natural gas supplies (in the absence of pipeline constraints). Generators using these alternative fuels and/or pipeline gas priced at a similarly high scarcity level then become the marginal, highest-cost generators that set wholesale electricity spot prices at an elevated level reflecting the higher costs. This situation is exacerbated by recent retirements of base load nuclear and coal-fired power plants and the decline of some gas supply sources, (e.g. eastern Canada gas production) and reduced LNG imports, while planned gas pipeline capacity has yet to be built.[4]

II. SUMMARY OF THE AGO'S COMMENTS

First, before the Department may consider DOER's proposal to authorize EDCs to purchase gas capacity with ratepayer backing, the Department must undertake a rigorous regional economic study of new gas capacity and alternatives, including: (1) analysis of market conditions, pipeline costs, and effect of planned market incentives; (2) modeling of solutions to address peak winter

[3] For example, New England natural gas basis differentials (calculated as Algonquin Citygate prices less Henry Hub prices) exceeded $10/MMBtu during 28, 54, and 20 days during the winters of 2012-2013, 2013-2014, and 2014-2015, respectively.
[4] "Maine Public Utilities Commission Review of Natural Gas Capacity Options," Sussex Economic Advisors, February 26, 2014, slides 5-6 and 12-40.

electric prices; and (3) evaluation of cost effectiveness, electric system reliability impacts, and carbon and fuel diversity impacts of those potential solutions.

Second, the Attorney General's Office ("AGO") questions whether DOER's proposal is consistent with the laws governing restructuring of the electric industry and the plain language of G.L. c. 164, § 94A. Further, as currently structured, the proposal lacks standard ratepayer protections such as competitive processes, transparency, avoidance of conflicts of interest, and incentives to achieve the best results for ratepayers.

Finally, the Department cannot make an informed decision on the complex issues raised in this docket based on stakeholder written comments. Rather, at minimum, the Department should conduct panel hearings and discovery to determine if there is agreement that winter electricity prices warrant state intervention and also to explore the scope of and procedure for conducting a meaningful regional study.

III. CAREFUL REGIONAL STUDY OF NEW GAS CAPACITY AND ALTERNATIVES IS WARRANTED

The Department posed a series of both DOER's and its own questions concerning mechanisms that should be considered as potential solutions to high electricity prices.[5] Before considering implementation mechanisms for a particular solution such as that suggested by DOER, the Department must evaluate the nature, scope and cause of the underlying issue and determine whether state intervention is needed to address the issue. If state invention is necessary, the Department must determine, based on consistent economic metrics, which combination of legally available options most cost effectively addresses the need while maintaining system reliability and meeting climate and other environmental requirements. To make a fully

[5] DPU Question 2; DOER Questions 2, 6. Order Opening Investigation, pp. 3-4.

informed decision, the Department must consider the results of a rigorous, regional economic study. The following analyses and modeling should be included in that study.

A. Analysis of Market Conditions, Pipeline Costs, and Effect of Planned Market Incentives

To answer the question whether there is a problem that warrants out-of-market state action, the Department should evaluate the scope of the pricing problem; what constitutes an unreasonable price in the context of the wholesale competitive market; whether there is a capacity scarcity; and whether there are mechanisms already in place that could timely address the issue.

Any evaluation of winter electricity pricing dynamics should first examine the fundamental cost of natural gas supplies and transportation into New England. New England's costs of delivered gas are unfortunately not going to be as low as in, say, Pennsylvania, which has abundant indigenous gas production and geological storage formations that New England lacks. As a result, New England's gas basis differential—the price of gas at the Algonquin citygate hub serving Boston minus the price at a liquid trading market, such as at Henry Hub in Louisiana (the benchmark price for North American natural gas)—can fluctuate sharply with the availability of pipeline capacity. These winter price spikes in gas can be seen below in Figure 1, which compares the daily price of natural gas in New England to the prices at Henry Hub. As shown, price spikes typically do not occur in the summer when natural gas demand for space heating purposes is low and New England's natural gas utilities do not fully utilize their pipeline capacity. [6]

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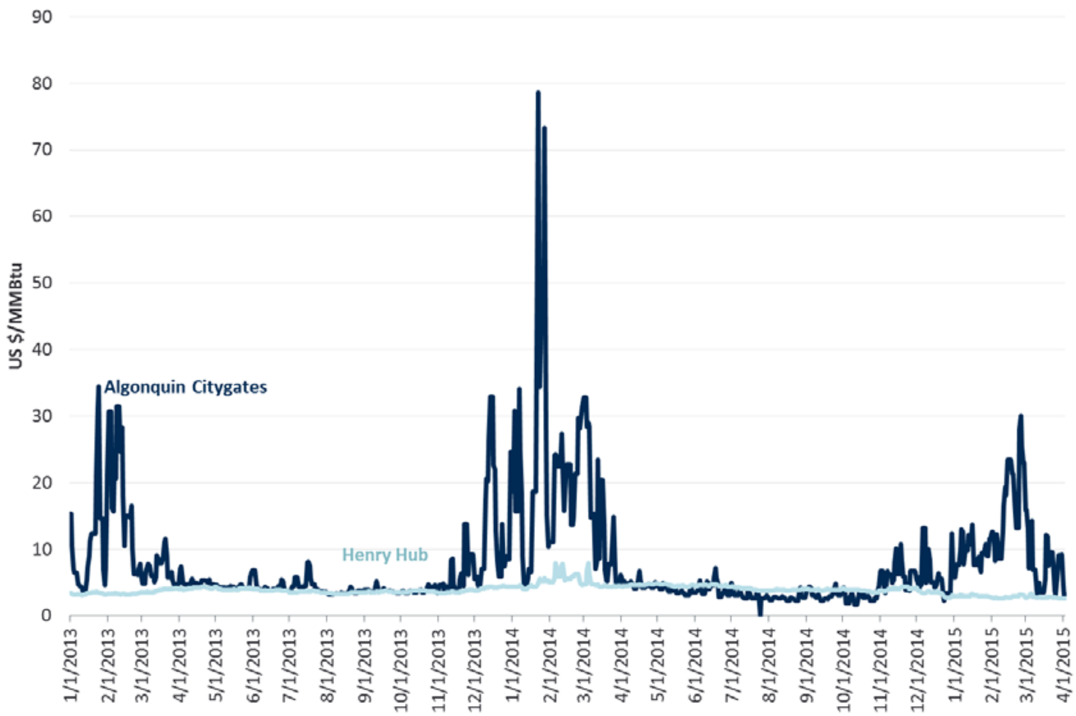
[6] One of the contributing factors to the winter price spikes shown in Figure 1 is the reduced quantities of LNG imports into New England in recent years. New England has historically relied on LNG to meet peak needs in winter periods. The Everett LNG terminal has been importing LNG since 1971, and delivers regasified LNG to Algonquin Gas Transmission, Tennessee Gas Pipeline, National Grid's (formerly Boston Gas Company) distribution system, and the Mystic Power electric generation plant in Everett. Another LNG import terminal that serves New England is the Canaport LNG facility in Saint John, New Brunswick that began service in 2009 and delivers

Figure 1
Daily Natural Gas Prices



Sources and Notes: ICE Day Ahead prices obtained from Ventyx EV.

Because the most significant basis differentials occur on a limited number of days in the winter months, any solution to address winter price peaks should be appropriately tailored to take into account the relatively limited time period during which the problem occurs. It would likely cost billions of dollars to build enough pipeline capacity or alternative generation resources (e.g.,

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regasified LNG into the Maritimes & Northeast Pipeline. A third LNG import terminal, Northeast Gateway LNG, is located offshore Massachusetts and delivers regasified LNG into Algonquin Gas Transmission. LNG deliveries to New England during the last three winters have been lower than the deliveries in the prior five winters, in spite of the last three winters having experienced the highest gas basis differentials. *See* "The Role of LNG in New England Gas Supply," GDF SUEZ Gas North America, presentation at the Northeast Gas Association meeting, slide 4, April 23, 2015; U.S. Energy Information Administration, "New England Spot Natural Gas Prices Hit Record Levels This Winter," Feb. 21, 2014 ("Two key supply-related factors have contributed to higher regional prices. First, deliveries of regassified liquefied natural gas (LNG) from Northeast terminals are down more than 30% so far in 2014 compared to the same period in 2013. Second, major pipelines transporting natural gas into New England have been congested. An expansion of the pipeline system could ease pipeline constraints, *but the cost-effectiveness of pipeline expansion projects (including their ultimate costs to consumers) remains a challenge*.")) (emphasis supplied), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=15111 renewables, transmission to remote hydro, etc.) to reduce the need for gas-fired generation enough to completely eliminate congestion and the gas basis differential during all times of the year, and, in any event, it is usually not economically efficient to build enough capacity to do so, since the last units added would be minimally utilized and would add little value. Rather, the long-term, economically efficient basis differential would equal the levelized cost of new pipeline capacity, which might be very roughly $1-$2/MMBtu on a levelized annual average basis. A basis differential approximating the cost of additional pipeline is the level at which shippers making long-term capacity commitments would expect to at least break even on their commitment.

Whether long-lived pipeline investments are economic depends on the costs to construct and operate the pipeline infrastructure, as well as current and future market conditions. For instance, before authorizing ratepayer-backed investment in new pipeline capacity, the Department should have recent data documenting, and a thorough understanding of relevant factors, including: (1) the current/future demand for gas; (2) the current supply of gas (including FERC-approved new pipelines); (3) how changes in gas supply and demand affect the price of electricity; and (4) the current and future availability and price of non-pipeline gas resources (particularly oil and LNG).

The Department also should consider whether there are mechanisms already in place that have or could address unreasonably high winter electricity prices without state action. For instance, the Department should analyze the winter of 2014-2015, where LNG and the ISO-NE winter reliability program helped maintain reliability and mitigate pricing concerns. Indeed, the region has not experienced any load shedding or blackouts during the past two winters, in spite of the unusual cold, largely because of oil-fired generation and LNG imports. In addition, the

Department should consider the impact of the ISO-NE's planned price incentives for generators to firm up their fuel and thus their availability ("Pay for performance" or "PFP").

To the extent the market is not pursuing solutions that the Department's or other policymakers' analysis find economic, the Department should analyze why not. One possibility is that the analysis may be flawed: it may incorporate unrealistic assumptions or ignore risks; or it may rely on evaluation metrics that do not capture the economic value created (as discussed below).

Another possibility regarding market inaction is that some market-based solutions are economic, but the sizable investments required face the threat of being undermined by future state actions that would depress their value. For example, interstate gas pipelines are typically built by developers who depend on long-term firm service commitments from shippers (e.g., LDCs, electric generators, marketers, industrial end-users). But shippers may be reluctant to make a long-term commitment if they believe that states might trigger further capacity expansions that reduce the basis differential into New England, to a level below the cost of their fixed rate contract commitments. This threat might lead to underinvestment in long-term, capital-intensive investments in gas infrastructure to serve New England generation needs.

B. <u>Modeling to Address Peak Winter Electricity Prices</u>

The core problem that needs to be carefully modeled is the limited availability of pipeline gas for electric generation and the cost of alternative ways to meet electricity demand during the coldest winter periods. In particular, the Department needs to consider whether alternative solutions to pipeline expansion would be more economic. For example, since pipeline constraints occur on only a few dozen days a winter, *see infra* Figure 2, some amount of a lower capital cost/higher variable cost solution (such as greater use of LNG) might be more economic.

In addition, electricity supplies from non-gas generation, such as renewables or large-scale hydro-electric generation connected via new electric transmission lines, also need to be considered, as do the costs and benefits of energy efficiency measures, conservation and demand side resources that reduce the need for additional gas capacity.

Reducing winter demand for pipeline gas through a variety of methods may turn out to be far more economic than obligating Massachusetts ratepayers to pay for long term contracts for firm transportation on a new pipeline and/or additional expanded pipelines. Further, reducing winter electric /natural gas pipeline demand to the extent possible will assist in "right-sizing" any potential solution that also includes increasing winter gas supply. Electric and/or pipeline gas demand reduction approaches would likely include combinations of (1) LNG contracts utilizing existing LNG infrastructure to ensure LNG availability and price stability; (2) additional non-gas electric generation, including remote renewables, or generation and transmission, including large-scale Canadian hydro, to reduce reliance on gas fired generation; (3) demand-side management for both natural gas and electricity to reduce peak gas demand; and (4) storage technologies for both electricity and natural gas. Many or most of these potential solutions already exist and could be pursued almost immediately. Thus, the Department should consider them fully before undertaking the potential solution of capacity in pipelines that have yet to be built or expanded. Moreover, even if a pipeline solution were ultimately considered appropriate, the Department should consider what amount of pipeline capacity is most economic since it is possible that smaller increments of capacity may yield higher net benefits than larger ones.

1. Gas-Electric System Interaction

Each candidate solution to high winter prices must be evaluated in a model representing how the electricity and gas systems interact, and how each solution would create economic value and/or meet other policy objectives as market conditions evolve. The Department will have to determine whether such evaluations have met the following criteria: reasonable representation of the gas-electric system; reasonable and transparent model input assumptions; consideration of key future uncertainties; comparison to alternative solutions; and use of appropriate economic metrics.

At a minimum, the modeling must include consideration of: (1) hourly electricity demand; (2) how much of that demand can be met by base load or other generation that would run irrespective of gas availability; (3) how much pipeline gas is available for electricity generation, given concurrent weather-driven gas LDC loads; (4) when pipelines become constrained, how much higher variable cost generation and demand response are available (and at what prices), with particular focus on oil-fired generation and LNG; and (5) environmental compliance costs.

The model should represent all of these factors, informed by available data about foreseeable system and market conditions. Some factors are inherently uncertain, which warrants analysis of a distribution of possibilities, or at least sensitivity analysis. Some are likely to change over time and the uncertainties and time trends can affect the economics of some solutions more than others. For example, the Department should consider:

- <u>Weather Distributions</u> - The assumed frequency and depth of cold periods will have a major effect on the value of different solutions. Thus, a realistic distribution of weather patterns should be modeled, along with the weather's effects on gas LDC demand (which affects pipeline availability) and electric demand.

- <u>Varying LNG Supplies</u> - LNG supplies may be high or low, depending partly on world LNG market conditions relative to New England conditions. Recognizing the possibility of low imports (especially if coinciding with cold weather) may increase the value of all solutions that firm up or increase winter supplies or reduce electric demand for gas.

- <u>Uncertain Availability of Oil-Fired Generation</u> - The availability of oil-fired generation may decrease if old oil-fired steam units retire or if gas/oil dual-fueled generators fail to maintain oil inventories. Oil inventories have been supported over the past two winters by ISO-NE's winter reliability program. In the future, ISO-NE plans to eliminate the program and rely instead on stronger price signals to incent generators to firm up their availability, through PFP incentives in its capacity market. Thus, the quantity (and price) of oil will be a significant source of uncertainty that might be analyzed through sensitivity or scenario analyses, particularly to produce reliability metrics, as discussed below.

- <u>Long-Term Decarbonization</u> - To meet its long-term mandatory greenhouse gas emission reduction targets under the Global Warming Solutions Act, Massachusetts must reduce its use of fossil fuels. Federal requirements also may impose reductions in power sector emissions. Meeting these targets likely will require aggressive investments in energy efficiency and renewable energy. Both will tend to reduce the value of long-lived pipeline solutions. Conversely, eventual retirement of the remaining nuclear and coal plants would increase the value of pipeline solutions.

- <u>Expected Pipeline Capacity Additions</u> - The model should account for the 342 MMcf/d Algonquin AIM and 72 MMcf/d TGP CT expansions that are expected to be online by winter of 2016/17.

2. <u>Evaluation of Cost Effectiveness of Potential Solutions</u>

Each proposed solution, including those involving gas capacity acquisition and those that do not, must be evaluated using uniform and appropriate metrics.

a. Total Resource Cost ("TRC")

The TRC metric is an appropriate economic metric for evaluating any proposed solution. The TRC measures the total economic cost to serve load and examines whether and how much a proposed project reduces total costs. The TRC metric indicates whether a project creates economic value in its own right, without considering any wealth transfers between energy producers and consumers as a benefit. [7] Application of the TRC metric to new pipeline capacity would involve estimating the fuel cost savings the incremental new capacity would provide, net of capital and fixed costs. The fuel savings are basically the incremental new volume of gas transported, multiplied by the cost savings from utilizing that gas (measured as the price at the

[7] The TRC also corresponds to the general approach to benefit-cost analysis, where the primary criterion is usually whether projects increase total social welfare, not just consumer surplus (the distribution of benefits and costs may be addressed separately).

receipt point end of the pipeline) instead of higher-priced oil or LNG fuels that would have been needed to serve electric load without the additional pipeline capacity.

The Department already uses criteria similar to the TRC in evaluating the cost effectiveness of renewable energy contracts. It calculates the net benefits of candidate contracts by multiplying the estimated energy output procured under the contract by the forecasted market price, and subtracting the direct cost of the contract, among other considerations. [8] The energy market prices used in this analysis reflect the marginal cost of production, and thus reflect the change in total resource cost. There is no consideration of price suppression. The Department also uses the TRC when evaluating energy efficiency programs. Similarly, ISO-NE also uses a variant of the TRC test, based on production costs savings rather than price impacts, when evaluating economic transmission investments.[9]

b. Price Suppression

The price suppression metric primarily reflects the change in market prices multiplied by the total customer load, without considering resource use or costs or revenues on the supply side of the economy. While the price suppression test might, at first blush, seem to be a sensible approach for evaluating the potential benefit to electric ratepayers of ratepayer-funded projects, it suffers from several major flaws. First, reliance on a price suppression analysis can lead to economically inefficient investment outcomes. Suppose, for example, a new $1 billion gas pipeline would be able to transport $200 million of Marcellus gas to displace $500 million of fuel oil used for electricity generation. The project would incidentally reduce gas basis

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[8] See D.P.U. 13-146 through D.P.U. 13-149, February 26, 2014, pp.40-56. Note that the Department's evaluation also includes the quantity of renewable energy certificates (RECs) multiplied by a projected spot price for RECs. It also considers non-quantifiable benefits associated with these renewable contracts (e.g., enhanced reliability, compliance with GWSA, etc.).

[9] ISO-NE Open Access Transmission Tariff (OATT), Attachment N, Section II.B available at: http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

differentials (for simplicity, assume to zero) and wholesale electricity market prices. This would reduce the price consumers pay not only to the generators who would have burned the oil, but to all electricity producers.[10] Suppose this price reduction lowers the generation component of customer bills by $1.5 billion.

How would the price suppression metric and the TRC test view this project? The price suppression metric would pass the project, with a net customer savings of $500 million ($1.5 billion minus $1 billion). The TRC test, however, would fail the project, since it recognizes that the $300 million fuel savings is not nearly enough to justify a $1 billion investment; total resource costs would increase by $700 million ($1 billion minus $300 million), indicating the investment destroys that much value and is not economic. In this hypothetical example, customer savings appear high because price suppression applies to all transactions, not just those electricity transactions directly affected by the new pipeline capacity. The difference between the customer cost savings and resource cost savings reflects a $1.2 billion ($1.5 billion minus $300 million) pure transfer of wealth from suppliers to consumers via suppressed prices (in addition to passing through to customers the $300 million resource cost savings). But even if such transfers were desirable, destroying $700 million of society's resources to accomplish it would be wasteful.

Relatedly, uneconomic projects justified by price suppression can displace more economic private solutions. If major new pipeline capacity were added (beyond any amount justified by the TRC metric) in order to suppress prices, the resulting artificially low price could discourage energy conservation or investments in renewable generation, nuclear plant uprates, LNG imports, or other actions that would have been more cost-effective than the pipeline. It also

[10] Producers affected by the lower prices include nuclear generation, renewable generation, gas-fired generation served by existing pipeline capacity (while also reducing the price they pay to holders of firm capacity on those pipelines), and other sources that are not physically affected by the pipeline.

could cause generation plants to retire prematurely. Such economic inefficiencies are not good for the economy nor for long-term consumer rates, which ultimately reflect the cost of supply. Indeed, supplier responses to distorted energy prices will tend to restore prices toward their original higher levels. For example, to the extent that energy prices remain suppressed in the long-term, electricity generators would have to increase the prices of their offers into the capacity market, leading to higher capacity prices.[11] Accounting for these factors would reduce the price suppression impacts and associated customer benefits of projects.

Pursuing projects based solely on the price suppression effect (treated as "value" in the price suppression test) could also undermine and interfere with the wholesale electricity market and Massachusetts' restructured regulatory construct. The stated purpose of the DOER/EDC plan to add pipeline capacity would be to reduce wholesale natural gas and electricity prices by increasing the supply and availability of natural gas capacity during the winter. However, the restructured Massachusetts electric market depends on market participants making investments where justified by the rewards they may earn in the wholesale markets, whether in the case of a nuclear plant uprate, a cargo of LNG, or any other decision about generation fuel sources. Market participants' willingness to invest depends on well-functioning markets that recognize the fundamental value they provide. If states sponsor un-economic projects (*i.e*., those that do not pass the TRC test) to suppress prices, state intervention may displace more economic investments. And the prospect of further interventions by the regulator may deter private investment entirely, by creating the possibility of future prices that are artificially low and impossible to predict because they depart from cost fundamentals. This prospect is particularly threatening in a relatively small, low-growth market such as New England, where one large project can have a large and long-term effect on prices.

[11] "Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," Samuel A. Newell and Matthew P. O'Loughlin, The Brattle Group, July 11, 2014, p. 21.

3. Evaluation of Electric System Reliability Impacts of Potential Solutions

Electric reliability also must be included in any consideration of potential solutions to high winter gas prices. One of the issues subsumed in concerns about high winter electricity prices due to insufficient natural gas availability is whether there will always be enough generation capacity and fuel to meet electricity demand. Electric reliability is typically measured using the Loss of Load Expectation (LOLE) metric to express how many times per year supply is likely to be inadequate to meet demand. Anything more than 0.1, or one event in ten years, is less reliable than the standard ISO-NE observes.

Winter reliability risks—and how candidate solutions might reduce those risks—should be addressed through both probabilistic and scenario analyses. The analyses should ask whether there are plausible scenarios regarding LNG, oil backup, and weather that could create reliability risks substantially beyond traditionally-accepted levels, and, and if so, whether candidate solutions would substantially reduce those risks. Such analyses should also consider the offsetting effect from consequent risk reductions in market-based solutions. For example, if the candidate solution depresses gas basis differentials, it might deter LNG imports or discourage investment in non-gas electricity supplies.

4. Evaluation of Carbon and Fuel Diversity Impacts

Any solution that includes investment in large amounts of long-lived energy infrastructure may affect the Commonwealth's policy goals, including its ability to meet future environmental compliance obligations. For example, fossil-fuel based investments run counter to meeting the carbon-reduction goals under the GWSA. Any analysis should account for emission allowance costs as well as other life-cycle costs such as methane emissions. Including such costs will reduce the value of natural gas-based solutions and, even more so, oil-based solutions.[12] Furthermore, if the analysis assumes long term reductions in gas and electricity demand and growth in renewable generation it will likely recognize less value in solutions that increase the long-term supply of natural gas.

The Department also should consider the benefits of fuel diversity. While fuel diversity is difficult to value monetarily, the TRC analysis would capture some of its value by evaluating scenarios where predominant sources become scarce (and the relative value of an alternative increases). For example, renewable generation and/or coal plants may have more value in a scenario with high natural gas prices.

A related consideration is that certain solutions could actually result in the unintended consequence of decreasing fuel diversity due to market response. For example, overinvestment in pipeline infrastructure that depresses gas and electricity prices could lead to the retirement of non-gas capacity (*e.g.*, nuclear capacity), which could ultimately result in over-dependence on natural gas-fired generation.

5. Prior Studies Flawed

The publicly available gas-electric studies for New England evaluate pipeline capacity projects based on price suppression metrics.[13] Additionally, those studies typically do not fully explain key assumptions or how gas-electric dynamics were modeled. The studies do not

[12] The TRC metric can also be expanded to a societal benefit-cost metric that includes environmental externalities, to the extent that the social costs of emissions exceed the assumed allowance prices.

[13] Studies include:
(1) "Massachusetts Low Gas Demand Analysis: Final Report," Synapse Energy Economics, January 7, 2015;
(2) "Access Northeast Project - Reliability Benefits and Energy Cost Savings to New England," ICF International, February 18, 2015, pp. 4-6, 27-33;(3) "Maine Public Utilities Commission Review of Natural Gas Capacity Options," Sussex Economic Advisors, February 26, 2014, slides 42-65; (4) "Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices," Competitive Energy Services, February 7, 2014, pp. 20-21; (5) "New England Cost Savings Associated with New Natural Gas Supply and Infrastructure," Concentric Economic Advisors, May 2012; and(6) "Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England," Black & Veatch, August 26, 2013.

evaluate alternative solutions against market uncertainties and a range of future scenarios, and most do not consider compliance with the GWSA.

For example, on behalf of the Massachusetts DOER, Synapse Energy Economics ("Synapse") evaluated the need for incremental pipeline capacity to serve Massachusetts gas and electric demand.[14] Using a gas-electric model, Synapse identified supply shortages in Massachusetts during winter peaks, but the key study assumptions, methods, and evaluation criteria are not particularly clear as presented. Synapse's focus solely on Massachusetts provides an incomplete picture. Even if there is a supply shortage to Massachusetts generators, external resources (*e.g.*, generators in other New England states) could be deployed to meet that need; and incremental pipeline capacity just to serve Massachusetts-based generation may not be required. A regional study is more appropriate for evaluating the need for solutions. Moreover, Synapse's assumptions with respect to pipeline capacity, cost of incremental pipeline, and electric sector demand need to be fully vetted and in some cases updated to reflect changed market conditions. Synapse did not consider LNG imports into terminals other than Everett and Canaport, even though Northeast Gateway imported LNG this past winter. Similarly, Synapse's study is likely outdated because it does not incorporate the recent sharp declines in global oil and LNG prices. In addition, it should be noted that Synapse's conclusions are not consistent with meeting GWSA targets (only two of the eight scenarios Synapse considered are compliant with implied 2030 GWSA targets).[15]

Because these studies rely to various extents on a flawed price suppression metric for evaluating cost effectiveness and fail adequately to explain assumptions and fully evaluate

[14] "Massachusetts Low Gas Demand Analysis: Final Report," Synapse Energy Economics, January 7, 2015, p. 3.
[15] As noted on p. 38 of the Synapse study, Synapse linearly interpolated the 2030 target using the 2020 and 2050 targets.

alternative solutions, the Department should not rely on them to inform the key policy decisions at issue in this docket.

IV. DOER's PROPOSED SOLUTION

In determining whether DOER's proposal is a viable option, the Department must first consider whether it is lawful, and if so, the Department must consider whether DOER's proposal provides the requisite ratepayer safeguards. For the reasons set forth below, the AGO has serious concerns regarding the legality of DOER's proposal, and questions whether it is consistent with the laws governing restructuring of the electric industry and the plain language of G.L. c. 164, § 94A. As well, the proposal lacks standard ratepayer protections such as competitive processes, transparency, avoidance of conflicts of interest, and incentives to achieve the best results for ratepayers.

A. The Restructuring Act

In 1997, the Legislature enacted a law to restructure the electric utility industry; this law substantially altered several statutes, including the Department's enabling statute, G.L. c. 164. *An Act Relative to Restructuring the Electric Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protection Therein*, St. 1997, c. 164 (the "Act" or "Restructuring Act"). In order to provide "affordable electric service" to all consumers, the Act significantly amended the existing Chapter 164 by "restructuring" the electric utility industry, thereby forcing the generation of electricity into a competitive market while leaving the distribution and transmission systems of the EDCs subject to public regulation. *See* St. 1997, c. 164, § 193; G.L. c. 164, § 1A(a), (e).

The general purpose of the Restructuring Act was to take EDCs out of the business of owning generation facilities, producing electricity, and buying fuel to produce electricity. *See* G.L. c. 164, §1A(b)(2) (referencing the electric companies' "requirement to divest generation facilities"); *Investigation by the Department of Telecommunications and Energy and the Energy Facilities Siting Board*, D.P.U. 98-84/E.F.S.B. 98-5, p. 2 (Aug. 8, 2003) ("The Restructuring Act . . . relieved electric companies of the obligation to plan for and serve the generation needs of their customers, except for those customers with standard offer or default service.")

The passage of the Restructuring Act thus resulted in a publicly-regulated distribution system and a competitive and open electricity supply market. *See* St. 1997, c. 164, §1(m). By pushing electricity generation outside of the Department's jurisdiction and into the competitive marketplace, the Restructuring Act "shifted the risks of generation development from consumers to generators, who are better positioned to manage those risks." *Investigation by the Department of Public Utilities on its own motion into the need for additional capacity in NEMA/Boston within the next ten years, pursuant to Chapter 209, Section 40 of the Acts of 2012 and pursuant to G.L. c. 164 § 76*, D.P.U. 12-77, p. 30 (Mar. 15, 2013). This shift in risk was intended to allow consumers to benefit from lower prices for electricity while also enjoying protection from the "construction, operational, and prices risks that were inherent in commodity rate regulation." Id. The Department has explained that, as a result of restructuring, it is suppliers who will "bear the risk associated with fluctuations both in wholesale commodity prices and [] load, risks that suppliers must take into account when determining" prices. *See Investigation by the Department of Telecommunications and Energy on its own Motion into the Provision of Default Service*, D.T.E. 02-40-B, p.8 (Apr. 24, 2003).

The Act also limited the Department's role in regulating activities related to generation. *See* G.L. c. 164, § 1A(e). Pursuant to G.L. c. 164, § 1A(e), "[a] generation company shall not be subject to regulation as a public utility or as an electric company, except as specifically provided in this chapter. A wholesale generation company shall be subject to regulation only as specifically provided in this chapter." One of the specific exemptions provided by the Restructuring Act, § 94G, authorizes the Department to exempt generators from Department review of recovery of costs related to fuel and purchased power via a fuel adjustment clause. This is a clear indication that the Legislature no longer intended for EDCs to be in the fuel buying business after restructuring. The limited role of the Department over the generation component of electricity service following the Restructuring Act "represents a clear policy choice that *electric generation resources are best developed in response to price signals from a competitive marketplace*." D.P.U. 12-77, p. 30 (emphasis supplied).

The Department itself has interpreted chapter 164 § 1A(e) as greatly limiting the Department's scope of authority over the wholesale generation industry, finding that Department jurisdiction does not extend beyond the "enumerated sections of G.L. c. 164 where the General Court explicitly provided for regulation of 'wholesale generation companies' by name." *Petition of USGen New England, Inc. requesting an Advisory Ruling by the Department of Telecommunication and Energy, pursuant to G.L. c.30, s.8 and 220 C.M.R. s.2.08(1)*, D.T.E. 98-107, p. 7-8 (Nov. 12, 1998). Aside from § 1A discussed above, explicit references to wholesale generation companies in G.L. c. 164 are limited to § 69R (regarding eminent domain); § 96 (exempting wholesale generation companies from statute requiring Department approval of mergers and acquisitions); and § 125A (regarding the supply of electricity to the Commonwealth or a municipality after expiration of a contract). *Petition of Exelon Corporation and Constellation Energy Group, Inc. requesting an Advisory Ruling by the Department of Public Utilities, pursuant to 220 C.M.R. s. 2.08*, D.P.U. 11-47, p. 7, n. 8 (Sept. 26, 2011). The Department's narrow interpretation of its authority over wholesale generation companies thus "supports the larger legislative design" because the goal of the Restructuring Act is the "deregulation of wholesale energy markets." *See id*., pp. 9-10.

As demonstrated by the authorities discussed above, the Department's execution of the statutory scheme put in place by the Legislature through the Restructuring Act has cemented the Act's intended removal of EDCs from the generation and supply markets for electricity. The mechanisms that formerly existed that would have allowed for Department regulation, review, and corresponding cost recovery through rates for costs associated with electricity supply—such as costs for commodity resources and capacity—are no longer viable because of the Restructuring Act. *See* D.P.U. 98-84/E.F.S.B. 98-5; *Boston Edison Company, Cambridge Electric Light Company, Eastern Edison Company, Fitchburg Gas and Electric Light Company, Massachusetts Electric Company, Nantucket Electric Company and Western Massachusetts Electric Company*, D.T.E. 98-13 (Feb. 20, 1998).

B. <u>G.L. c. 164, § 94A</u>

DOER's proposal also appears to be inconsistent with the plain language of G.L. c. 164, § 94A. The plain language of G.L. c. 164, § 94A does not authorize the Department to approve contracts for natural gas capacity entered into by EDCs. Rather, it limits the Department's authority to approving long-term contracts for gas or electricity supply entered into by respective gas or electric distribution companies. The statue states in pertinent part:

> No gas or electric company shall hereafter enter into a contract for the purchase of gas or electricity covering a period in excess of one year without the approval of the department, unless such contract contains a provision subjecting the price to be paid thereunder for gas or electricity to review and determination by the department in any proceeding brought under section ninety-three or ninety-four . . . . Any contract covering a period in excess of one year subject to approval as aforesaid, and which is not so approved or which does not contain said provision for review, shall be null and void.

G.L. c. 164, § 94A. The statute clearly states that long-term contracts for "gas or electricity" entered into by "gas or electric" companies are subject to Department review. G.L. c. 164, § 94A. Traditionally, this language has been construed by the Department to apply to gas company purchases of gas and electric company purchases of electricity. To read the statute otherwise (i.e., to apply it to electric company purchases of gas) would violate the statutory construction maxim *reddunda singular singulis* or "referring each to each." *See Commonwealth v. Barber*, 143 Mass. 560, 562 (1887); 2A Sutherland Statutory Construction § 47:26 (7th ed.). "The different portions of a sentence . . . are to be referred respectively to the other portions . . . to which we can see they respectively relate, even if strict grammatical construction should demand otherwise." *Barber*, 143 Mass. at 562.

Legislative history also clearly demonstrates that the Legislature meant to relate purchases of electricity to electric companies and purchases of gas to gas companies. *Water Dep't of Fairhaven v. Dep't of Envtl. Prot.*, 455 Mass. 740, 744 (2010), quoting *International Org. of Masters v. Woods Hole, Martha's Vineyard & Nantucket S.S. Auth.*, 392 Mass. 811, 813 (1984) (statutes are interpreted with the purpose "to effectuate the intent of the Legislature in enacting it."). When § 94A was first enacted on April 30, 1926, it addressed only the purchase of electricity by electric companies. *An Act Providing for the Approval by the Department of Public Utilities of Certain Contracts of Electric Companies*, St. 1926, c. 298 (Apr. 30, 1296). On May 22, 1930, G.L. c. 164, § 94A was amended to include purchases of gas by gas companies, with the amended language specifying "contracts of gas companies and of electric companies for the purchase of gas or electricity." *An Act Relative to Approval by the Department of Public Utilities of Contracts of Gas Companies and of Electric Companies for the Purchase of Gas or Electricity*, St. 1930, c. 342 (May 22, 1930).

Department precedent also supports this plain reading of the statute. While the Department has taken a broad view of its authority to review various gas contracts entered into by gas companies to include the authority to review and approve all "third-party resource contracts,"[16] it has never expanded the scope of the statute to consideration or approval of purchases of pipeline capacity by EDCs, and certainly not to EDCs buying pipeline capacity at wholesale and then reselling it.

DOER argues that the language of § 94A is ambiguous in the context of DOER's proposal because the language "neither explicitly forbids nor expressly allows"[17] the Department to review electric companies' contracts for gas pipeline capacity. However, even if the Department were to find the language ambiguous, the Department could not interpret § 94A to extend to a review of gas pipeline contracts entered into by electric companies because to do so would be inconsistent with Chapter 164 as a whole and the Department's general statutory authority. When a court finds ambiguity in the language of a statute, its analysis will progress to a consideration of the cause of the statute's enactment, "the mischief or imperfection to be remedied and the main object to be accomplished, to the end that the purpose of its framers may be effectuated." *DiFiore v. American Airlines, Inc.*, 454 Mass. 486, 490 (2009), quoting *Industrial Fin. Corp. v. State Tax Comm'r.*, 367 Mass. 360, 364 (1975). A court will "construe the various provisions of a statute in harmony with one another, recognizing that the Legislature

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[16] *See Investigation by the Department of Public Utilities*, D.P.U. 86-36-G, p. 101. For example, the Department reviews contracts entered into by LDCs for natural gas capacity under § 94A. *See, e.g.*, *New England Gas Company*, D.P.U. 13-02 (Sept. 20, 2013) (approving extension of contracts between gas company and pipeline for upstream capacity under § 94A); *Commonwealth Gas Company*, D.P.U. 94-174-A, p. 27 (March 15, 1996) (describing review process for both capacity and commodity resources under § 94A). The Department has also used its § 94A authority to approve contracts for wind power-generated electricity and renewable energy certificates ("RECs") by an electric company. *NSTAR Electric Company*, D.P.U. 07-64-A (Apr. 30, 2008).

[17] *See Massachusetts Teachers' Ret. Sys. v. Contributory Ret. Appeal Bd.*, 466 Mass. 292, 301 (2013) (quoting *Goldberg v. Board of Health of Granby*, 444 Mass. 627, 635 (2005)).

did not intend internal contradiction." *Id.* at 491. *See* also *Eaton v. Fed. Nat. Mortgage Ass'n.*, 462 Mass. 569, 583 (2012).

Accordingly, when interpreting any possible ambiguities in § 94A, it is necessary to look to the larger statutory scheme embodied by Chapter 164 of the General Laws. In this case, any interpretation of § 94A that would allow EDCs to purchase resources related to supply of electric generation (in this case, natural gas capacity) and would allow the Department to regulate such activity would appear to undermine the "main object to be accomplished" by the Restructuring Act, *i.e.* to move from a regulated electricity supply market to an open and competitive market for power. *See* St. 1997, c. 164, §1(f) Furthermore, an interpretation of § 94A that included approval of pipeline capacity contracts by EDCs would contradict the specific statutory provisions put in place under G.L. c. 164 to account for the divestiture of all generation assets by EDCs. *See, e.g.*, G.L. c. 164, §1G. This interpretation also would give rise to an inconsistent body of regulatory law. See D.P.U. 98-84/E.F.S.B. 98-5 (exempting EDCs from G.L. c. 164, § 69I and rescinding 220 C.M.R. 10.00 et seq.); D.T.E. 98-13 (exempting EDCs from G.L. c. 164, § 94G). Thus, an interpretation by the Department that it has the authority to approve pipeline capacity purchases by EDCs would not be reasonable and would not be accorded deference.[18]; *See, e.g., Franklin Office Park Realty Corp. v. Comm'r of Dep't of Envtl. Prot.*, 466 Mass. 454, 463-64 (2013), quoting *DiFiore*, 454 Mass. at 490-491 (finding the DEP's ruling unreasonable because "our respect for the Legislature's considered judgment dictates that we interpret the statute to be sensible, rejecting unreasonable interpretations unless the clear meaning of the

[18] The so-called "public interest exemption" of § 94A does not apply here. The exemption provides that "[t]he department is authorized to exempt any electric or generation company from any or all of the provisions of this section upon a determination by the department, after notice and a hearing, that an alternative process or incentive mechanism is in the public interest." G.L. c. 164, § 94A. The § 94A exemption cannot apply to gas capacity contracts entered into by electric companies, because the contracts do not fall within the scope of § 94A in the first instance.

language requires such an interpretation"); *Massachusetts Teachers' Ret. Sys.*, 466 Mass. at 301, quoting *Goldberg v. Board of Health of Granby*, 444 Mass. 627, 635 (2005) (finding that when a statute "neither explicitly forbids nor expressly allows the regulation in question" the Court will consider whether the regulation is a "reasonable resolution of the statute's silence").

The Department also does not have general authority under G.L. c. 164, § 76 to review and approve supply-related contracts entered into by EDCs. While the Department has broad authority to generally supervise EDCs pursuant to G.L. c. 164, § 76 (*See Massachusetts Elec. Co. v. Dep't of Pub. Utilities*, 419 Mass. 239, 245-247 (1994)), the Department can only assert its general authority to the extent that the exercise "carries out the scheme or design of the chapter [164] and is thus consistent with it." *Cambridge Elec. Light Co. v. Dep't of Pub. Utilities*, 363 Mass. 474, 494 (1973). Here, as discussed above, any assertion of authority over EDCs' gas supply contracts would be inconsistent with the Legislature's restructuring scheme. *See Cambridge Elec. Light Co.*, 363 Mass. at 494.

In sum, it is difficult to envision a scenario in which the Department successfully could assert legal authority over gas capacity contracts entered into by EDCs without specific authorization to do so by the Legislature.[19]

C. <u>Implementation Considerations</u>

To the extent that a comprehensive regional study identifies a solution to high winter electricity costs that involves increasing winter gas supplies through regulatory intervention and that also comports with Massachusetts and federal law, the Department should ensure (1) a competitive, transparent procurement process that avoids conflicts of interest; and (2) the fair

[19] The AGO notes, but does not address here, *PPL Energy Plus, LLC et al. v. Nazarian, et al.*, 753 F.3d 467 (4th Cir. 2014) and *PPL Energy Plus, LLC et al. v. Solomon, et al*., 766 F.3d 241 (3d. Cir. 2014).

management of any procured capacity that achieves the Department's stated goals for the benefit of ratepayers.

1. Ensuring a competitive and transparent procurement

If the Department considers procurement of new pipeline capacity and/or LNG (or other solutions that would involve procurement), it will want to ensure that the procurement process is as competitive as possible. Typically, such a competitive process would involve a well-publicized solicitation of offers from all potential suppliers through a request for proposals or other similar open and transparent procurement process. The DOER proposal does not contemplate any type of competitive procurement. Instead, it appears to suggest sole sourcing all capacity purchases from the as yet to be built pipeline affiliate of the EDCs. This is not fair or acceptable.

2. Avoiding Conflicts of Interest

A significant concern regarding EDC procurement of new pipeline capacity and/or LNG supplies is the simultaneous participation of EDCs as equity owners in some of the proposed pipeline projects to New England. Eversource Energy and National Grid are equity owners in Spectra Energy's Access Northeast pipeline project, with the equity stakes being 40%/40%/20% for Spectra, Eversource Energy, and National Grid, respectively. In other words, affiliates of Massachusetts EDCs will own sixty percent of the Access Northeast pipeline, whose creation and financial viability will be assured by Eversource's and National Grid's customers pursuant to long term contracts that are proposed between the EDCs and the Access Northeast pipeline. The EDCs' participation in the pipeline projects as equity owners raises concerns about a potential conflict of interest for those EDCs in selecting and negotiating candidate solutions on behalf of ratepayers. With equity interests in some proposed projects, the EDCs may have an incentive to put their shareholder interests above ratepayer interests when it comes to making procurement decisions for new natural gas capacity.

The conflict of interest could manifest itself in multiple ways. For example, the EDCs may no longer have an incentive to use a competitive procurement process to achieve the best outcome for ratepayers. They might instead have pre-judged the competition to provide new pipeline or LNG supplies to New England by favoring the projects in which they have taken equity stakes. They may no longer look for the lowest cost solution, or the solution that minimizes the commitment made by ratepayers. The EDC may instead have an incentive to pursue larger, more capital-intensive projects than are necessary to solve the winter price spikes identified earlier as such projects may help increase shareholder profits of their parent companies at the expense of ratepayers. They may also no longer have an incentive to negotiate with the pipeline on an arms'-length basis so that ratepayers receive the best deal possible.

3. <u>Procurement by Entities Other than EDCs</u>

Having procurement done by an independent entity would be a superior option to having it performed by the EDCs, which have no experience procuring gas and, as noted above, have inherent conflicts of interest. Such an independent entity would be more likely to conduct an open procurement process and evaluate all pipeline and LNG supply alternatives that are available, without favoring or pre-judging specific projects. In addition, an independent entity might also provide a more reasonable assessment of the size of potential solutions and the necessary ratepayer volume commitments, since those will be determined without any consideration of the profitability of specific projects to project shareholders. Procurement of new gas supply capabilities by an independent entity would also require a mechanism for passing along the costs to electric ratepayers through the EDCs.

4. Management of pipeline capacity contracts and remarketing of capacity

For the sake of transparency and best practices, any contracts for gas or pipeline capacity should be subject to a capacity management agreement with a third-party asset manager. That manager would then take on the duty of optimization of the pipeline contract, similar to the LDCs' asset management agreements. The Department would approve the terms of these asset management agreements.

5. Procurement Examples from other Jurisdictions

The Department asked, in Question 15, whether there were other regions or states where EDCs contract for firm natural gas capacity.[20] Maine currently is evaluating electric ratepayer-funded incremental pipeline solutions to protect against the same price and reliability pressures that face Massachusetts and the rest of the New England energy market.[21] One similarity to Massachusetts is that Maine has a restructured retail market, where providers do not have captive customers and so do not sign long term contracts and where customers are exposed to market prices. However, Maine's process for pursuing fuel supply solutions is quite different from the process the Department is entertaining. Unlike Massachusetts, Maine has legislation in place that enables the Maine Public Utility Commission ("PUC") to procure pipeline capacity on behalf of customers, and to negotiate and enter contracts for the resale, evaluation and administration of the purchased capacity. The Maine statute avoids the conflicts of interest associated with EDCs' procurements and consideration of projects, by giving that authority to the PUC. Unlike Massachusetts, the AGO is not aware of any of Maine's EDCs taking an equity interest in any of the projects being considered there. Maine's legislation also limits the risk to

[20] Order Opening Investigation, p. 5.

[21] *See Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. §1901*, Maine Public Utilities Docket No. 2014-00071.

ratepayers of bad investments by limiting the amount of pipeline capacity and the size of the investment allowed to 200 MMcf/d or $75 million annually. The legislation also prohibits the Maine PUC (or other entities that it directs to procure on behalf of the ratepayers) from procuring pipeline capacity if market or rule changes or private investments would achieve similar cost reduction to the ratepayer-funded pipeline. This is a valuable concept that is aligned with the AGO's idea of first identifying solutions that the market can provide and/or alternative solutions (e.g., incremental energy efficiency programs).

Connecticut has recently enacted legislation that allows for the state to purchase pipeline capacity[22] although no regulatory proceeding for implementation has yet been commenced. The bill allows the Connecticut Department of Energy and Environmental Protection, in furtherance of the state's Integrated Resource Plan, and in consultation with the Office of Consumer Counsel, and the attorney general, to solicit proposals for long term contracts from providers of: natural gas pipeline capacity constructed on or after January 1, 2016; liquefied natural gas; Class I renewable energy sources (e.g., wind, solar, or fuel cell power); active demand response resources, including load management; distributed generation, including combined heat and power; or verifiable large-scale hydropower. The costs of acquiring natural gas capacity and the other named resources will be passed through to electric ratepayers. The Connecticut legislation's fuel neutrality and its requirement that Consumer Counsel and the Attorney General be involved in the capacity solicitations represent valuable safeguards that presumably will help ensure the integrity of the needs assessment and the procurement process.

[22] Senate Bill 1078, *available at* http://www.cga.ct.gov/2015/FC/2015SB-01078-R000616-FC.htm.

V. SUGGESTIONS FOR FURTHER PROCEEDINGS

The Department suggests that, after receipt and review of comments and reply comments, it will consider subsequent procedures, whether technical conferences and/or panel hearings.[23] The AGO agrees that "next steps" should properly wait until the full scope of stakeholder comments and proposals are reviewed. The process selected by the Department should be designed to first determine if there is agreement that the behavior of winter electricity prices is such as to warrant state intervention and to explore the scope and procedure for conducting a meaningful regional study. Technical conferences and panel hearings might be a useful mechanism for interested parties to exchange ideas and acquire a better threshold understanding of differing viewpoints on these issues, and how these differing viewpoints can be evaluated and explored.

Such processes, however, while useful for informally sharing ideas and information, are ill-suited to resolving contested issues of policy or facts with all of the procedural safeguards assured by the Massachusetts Administrative Procedures Act, G.L. 30A.[24] In any subsequent adjudicatory process concerning implementation of possible solutions, the proponent of a particular action would have the burden to establish the economic merits of its proposal. The Department also should require a proponent to show how it considered and analyzed the benefits in comparison to other potential solutions. This step is crucial because it likely will be the case that several proactive measures might have the effect of reducing winter electricity prices and the Department would be in the position of selecting a proposed candidate solution that offered greater benefits at a reduced cost over other, possible solutions. A proponent would make such a showing by demonstrating that a range of possible alternatives was evaluated against a consistent

[23] Order Opening Investigation, p. 6.
[24] *See* G.L. c. 30A, §§ 10, 11 and 14.

set of economic metrics, as discussed in these comments. The proponent would establish the superiority of its preferred solution, as well as demonstrating that the scale of its proposal was properly sized to address the problem.

A proponent of a particular candidate solution also should demonstrate how its proposal is the product of an open, fair, and transparent procurement solicitation process. That showing will go far in assuring that any solution that ratepayers expected to pay for is economic. Proposals advanced by the EDCs also must show that shareholder interests were not placed ahead of ratepayer interests and consistency with affiliated transaction rules. In short, EDCs must establish how their proposal furthers the public interest better than alternative candidate solutions. The Department should evaluate proposals using standard procedural safeguards and evidentiary requirements of ch. 30A, including pre-filed testimony, opposing testimony, discovery, cross-examination and post-hearing briefs.

Respectfully submitted,

ATTORNEY GENERAL
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By: ______________________

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities into the Means by which New Natural Gas Delivery Capacity may be added to the New England Market	**D.P.U. 15-37**

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding in accordance with the requirements of 220 C.M.R. 1.05(1) (Department's Rules of Practice and Procedure). Dated at Boston this 15th day of June 2015.

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