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March 29, 2016

Rob Klee
Commissioner
Connecticut Department of Energy and Environmental Protection
79 Elm Street
Hartford, CT 06106-5127

Re: DEEP – BETP RFP for natural gas capacity, liquefied natural gas (LNG), and natural gas storage procurement

Dear Commissioner Klee:

The American Petroleum Institute (API) appreciates this opportunity to comment on the Department of Energy and Environmental Protection’s (DEEP) RFP for natural gas capacity, liquefied natural gas (LNG), and natural gas storage procurement. While API has no comment on the specific terms of the RFP, we would like to express our support for the use of the types of agreements envisioned by the RFP to support development of necessary pipeline infrastructure as and ensure reliable gas delivery for power generation.

API is a national trade association representing over 650 member companies involved in all aspects of the oil and natural gas industry. API’s members include producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of the industry. API advances its market development priorities¹ by working with industry, government, and customer stakeholders to promote increased demand for and continued availability of our nation’s abundant natural gas resources for a cleaner and more secure energy future.

Natural gas plays a crucial role in maintaining the cost-effectiveness and reliability of electricity in the region. Connecticut and the other New England states are all in the top ten for highest energy costs.² These costs are driven by natural gas pipeline capacity constraints, particularly during seasonal peaks in demand.³ The region must establish new and expand existing means for

¹ Effective January 1, 2016, America’s Natural Gas Alliance (“ANGA”) dissolved as a separate organization but its mission — to promote the demand for and use of natural gas — and a supporting staff team was combined into the API.

² WalletHub, 2015’s Most & Least Energy-Expensive States, <https://wallethub.com/edu/most-least-energy-expensive-states/4833/>

³ Along with many other entities, ISO-NE, the region’s power system operator and wholesale electricity market administrator, has frequently stated their position that the pipeline delivery system is constrained during the winter peak demand periods and has advocated for increased pipeline capacity. Most recently, their concerns were discussed in their

natural gas delivery to reduce congestion and increase natural gas capacity available for electricity generation during these peak demand periods. As such, the development of additional natural gas pipeline infrastructure is critically needed.

API's Market Development Department (formerly ANGA) has been an active participant in the dockets in New Hampshire and Massachusetts referenced by DEEP that have resulted in initial agreements between LDC's and pipeline developers. A copy of our comments (submitted as ANGA) discussing EDC capacity agreements is attached. As discussed in those proceedings, the construction of additional energy infrastructure, including additional natural gas pipeline capacity, will have direct benefits to consumers. According to a 2015 study commissioned by the New England Coalition for Affordable Energy, failure to build more energy infrastructure will cost the region \$5.4 billion in higher energy costs and reduce household spending by \$12.5 billion.⁴

Decreasing energy costs is one benefit of increasing natural gas infrastructure, but the environment also gains when a cleaner fuel is used. Data shows that natural gas is the prime power source in 11 of the 22 states with below average emission rates.⁵ By utilizing more natural gas in power generation, the United States has reduced its carbon emissions by 728.72 million metric tons from 2005 to 2012 – the largest reduction by nearly 600 million tons compared to the world's top 20 economies.⁶

Utilizing new mechanisms, such as firm natural gas pipeline capacity contracts by EDCs will greatly reduce financial risks faced by ratepayers. The current model of natural gas distribution exposes ratepayers to high market spot prices in times of high demand or congestion. A longer-term contract for this delivery will secure supply and reduce volatility, providing a hedge against future spikes.

API applauds the DEEP for seeking new and innovative ways to improve supply and reliability for the state's gas and power customers. Please find below answers posed to the questions contained in the notice accompanying the RFP.

Sincerely,



Marty Durbin

⁴ "State of the Grid: 2016" presentation delivered on January 26, 2016, available at http://www.iso-ne.com/static-assets/documents/2016/01/20160126_presentation_2016stateofthegrid.pdf.

⁵ The Economic Impacts of Failing to Build Energy Infrastructure in New England, La Capra Associates and Economic Development Research Group, August 25, 2015, <http://media.gractions.com/5CC7D7975DFE1335100A9E9B056042840005CCF0/25e72b85-c007-4b98-a851-8b31563c9559.pdf>

⁶ U.S. Energy Information Administration, State Energy Data System - <http://www.eia.gov/state/seds/>

⁶ U.S. Energy Information Administration, Emissions Data; World Bank, GDP Data

Enclosures: API responses to questions posed by DEEP in the March 9, 2016 RFP Notice
ANGA Response to MA DPU 15-37

API RESPONSES TO QUESTIONS POSED BY DEEP IN MARCH 9, 2016 RFP NOTICE

- 1.) (ALTERNATIVE GAS RESOURCE BIDDERS) Identify the incremental reliability benefits that would be generated if the Alternative Gas Resource Bidders were to bid a pre-arranged capacity releases for excess capacity or any other natural gas resources? What would be the magnitude of such benefits?

API supports the recognition of Alternative Gas Resources (AGR) as a supplement to new pipeline capacity. An integrated combination of resources should be used to address the growing market for natural gas in general and for power generation in particular. The incremental reliability benefits of AGR are limited, however, to the commitment that can be made by the AGR Bidders. In cases involving LDCs or other consumers, commitments will usually be seasonal and may only be available when demand for home heating is low (i.e. in the summer, not in the winter when gas is in high demand for heat and power generation). The potential magnitude is also heavily dependent on the willingness of the potential AGR Bidders to participate in separate arrangements for gas supply in addition to capacity release. This is an area where Asset Managers engaged by the LDCs could be helpful because they manage large portfolios of resources from multiple LDCs or other customers, providing them with some flexibility in managing constriction. However, avoiding constriction when heating loads compete with generation loads will likely continue to be challenging. Additionally, the likelihood of asset managers having any success in managing such constriction is dependent on the addition of new pipeline capacity in the market.

- 2.) (ALTERNATIVE GAS RESOURCE BIDDERS) Differentiate between the reliability benefits generated from utilizing existing natural gas resources, currently subscribed incremental natural gas capacity and/or any other natural gas resource, to new incremental gas capacity infrastructure proposals.

API believes that the primary differences between reliance on “double use” of existing resources and commitment to new gas capacity infrastructure are (1) the degree of control, (2) the ability to negotiate particular service concessions with pipelines, and (3) most importantly, the inescapable fact that diversion of existing capacity to support peak loads such as power generation does not increase the total capacity available to an already-constrained market. LNG or other resources that actually do add to the total capacity can, of course be helpful in increasing the amount of gas available, but only as part of the answer. Meanwhile, released capacity, whether in incumbent systems or already-subscribed incremental systems, in theory, could as reliable as new capacity but its availability is highly dependent on the nature and reliability of the commitment of the releasing party. As long as the incumbent holder can control the terms of the basic service being released, it cannot be as flexible as a new arrangement with a pipeline. The most important factor in the reliability of the commitment is the inclusion of any recall provisions, which in the case of most regulated LDCs are essential to protecting their public-service obligation.

- 3.) (ALTERNATIVE GAS RESOURCE BIDDERS) Identify and elaborate on the statutory or regulatory requirements at the federal or state level that would impede or preclude the Alternative Gas Resource Bidders from pre-arranged capacity releases subject to the requirements of the RFP.

API recognizes that FERC capacity release rules surrounding prearranged releases and FERC rules regarding “shipper must hold title” can potentially impede AGR Bidders from making effective use of prearranged releases. However, FERC has shown strong flexibility in adapting its rules to support state-regulator-endorsed programs and programs such as asset management, to enhance least-cost reliability. It is unknown what state restrictions might become an issue, especially when it comes to LDC curtailment priorities. For example, any commitment to release LDC firm capacity to support power generation, or even to use the LDC’s firm capacity to ensure service to behind-the-gate power generation, would be subject to the prioritization of LDC service to ensure heating supply for essential-human-needs customers. In a cold winter, experience has proven that it is very difficult for an LDC or a state regulator to ensure service to a power generator because of the tension among competing needs for home heating and electricity.

- 4.) (ALTERNATIVE GAS RESOURCE BIDDERS) If an Alternative Gas Resource Bidder were to submit a bid, explain what would be the implications of any recall provisions, if any were required by the Bidder or allowed by DEEP, that would be included in such a bid.

As noted earlier, API believes strongly that any recall provisions undermine the dependability of released capacity. Especially in the case of LDCs, the most likely periods that capacity would be recalled would be during the heating season when LDC loads and generation loads reach coincident peaks and thus are competing for the same capacity. This is another area where LDC curtailment priorities may also be an issue.

- 5.) (ALTERNATIVE GAS RESOURCE BIDDERS) DEEP’s interpretation of Section 1(d) of the Act is that a long term solution is required to improve the affordability and reliability of electric supply reliability. Will the Alternative Gas Resource Bidders be able to provide a primary firm service contract proposal that has a minimum term service of at least 5 years?

API understands that long-term solutions from AGR Bidders will be case-specific, subject to some basic questions: (1) Can a long-term prearranged release be allowed by FERC? (2) Can gas supply be diverted for that period on a contingent basis, in addition to the regulated release of capacity? (3) Is the long-term release subject to any changes in state regulatory policy during its term? Some AGR Bidders, such as terminal-supplied LNG, can certainly make such longer-term commitments, assuming they have the LNG supply contractually available, and are not subject to any changes in regulatory policy at the Federal level. Meanwhile, as for released capacity and supply, this is another area where Asset Managers could play a role in putting a large enough portfolio of released resources in play to be able to supplant one resource with another if any unforeseen changes could impair long-term reliability.

- 6.) (ALTERNATIVE GAS RESOURCE BIDDERS) Have the Alternative Gas Resource Bidders taken the necessary steps to ensure that they can legally acknowledge that each bid has been submitted with has no knowledge of any non-public information associated with the development of this RFP? Explain, in detail, the steps that each entity has or will take to ensure that such bids comply with the aforementioned question.

API recognizes that this is a question directly addressed to the AGR Bidders, and as such API has no input.

- 7.) (ALTERNATIVE GAS RESOURCE BIDDERS) What requirements and changes to this RFP would need to be modified or added in order to evaluate bids received from Alternative Gas Resource Bidders? Provide the changes, verbatim, that would need to be incorporated to the RFP. Also identify the sections and provisions that would not apply to each type of Alternative Gas Resource Bidder, and also how those sections or provisions would need to be modified.

API believes that a detailed review of the RFP could reveal areas requiring such adjustment to accommodate AGR Bidders. However, we would observe that an AGR Bidder should be able to define their bid in terms of the criteria prescribed for new-capacity bids: Price, term, reliability, flexibility, etc.

- 8.) (CAPACITY RELEASE AND ASSET MANAGER) If Connecticut were to design similar policies and procedures for releasing capacity and selection of an Asset Manager, what should be DEEP's and/or the Public Utilities Regulatory Authority's ("PURA") role in the selection, oversight, and regulation of the Asset Manager, etc.?

API has no opinion at this time as to which state entity should select and oversee the asset manager. However, as the PURA has existing oversight of rates charged and LDCs and EDCs they may be in the best position to evaluate the existing agreements by both participant classes and oversee a potential asset manager's activities.

OVERALL: *Alternative Gas Resource Bidders, whether LDCs, Asset Managers holding LDC capacity, LNG suppliers, or other firm pipeline customers, can be a valuable resource in building a "wedding cake" of available generation fuel resources. However, given the competition for capacity when heating loads compete with winter generation loads, it is, in API's opinion, very unlikely that AGR Bidders could ever supplant the need for significant new pipeline capacity into Connecticut.*

June 15, 2015
VIA Electronic Mail
Mark D. Marini, Secretary,
Department of Public Utilities,
One South Station, 5th Floor,
Boston, Massachusetts 02110

Re: Investigation by the Department of Public Utilities on its own Motion 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 electric distribution companies.
(D.P.U. 15-37)

Dear Mr. Martini:

Please find the enclosed comments from America's Natural Gas Alliance (ANGA).

Sincerely,



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ANGA RESPONSES TO MASSACHUSETTS DPU 15-37 QUESTIONS

America's Natural Gas Alliance (ANGA) appreciates this opportunity to inform the Massachusetts Department of Public Utilities' (DPU or Department) investigation into new natural gas capacity in the New England market. We agree with DPU and the Massachusetts Department of Energy Resources (DOER) that natural gas plays a crucial role in maintaining the cost-effectiveness and reliability of electricity in the region, and that the region must establish new and expand existing means for natural gas delivery to reduce congestion and increase natural gas capacity available for electricity generation during peak demand periods.

Representing North America's leading independent natural gas exploration and production companies, ANGA works with industry, government, and customer stakeholders to ensure the continued availability of natural gas and to promote the increased use of this abundant domestic resource for a clean and secure energy future. The safe and environmentally responsible development of our domestic natural gas resource has been, and increasingly will be, an important component of America's energy security and economic health. As both energy producers and consumers, ANGA has a keen interest in the production of electricity from clean-burning, affordable natural gas.

ANGA offers the following responses to DPU's April 27, 2015, order opening 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 electric distribution companies.

DOER Questions

- 1. Is there any legal impediment to the Department accepting and considering natural gas capacity contracts by EDCs under Section 94A and, if approved, providing reasonable assurance of cost recovery?**

As DOER notes, although § 94A says that either electric or gas companies can contract for electricity or gas, DPU has never had to use the provision to review a long term contract by an electric company for gas or pipeline capacity, only electric companies contracting for electricity and gas companies for gas. However, there is no legal impediment to the Department accepting and considering natural gas capacity contracts by EDCs under Section 94A and providing assurance of cost recovery. The Department regularly approves natural gas capacity contracts by gas distribution companies under Section 94A.⁷ The plain language of Section 94A makes it apply to purchases of gas or electricity by gas or electricity companies, and there is no court or Department interpretation or regulation to our knowledge that would override the plain language of Section 94A. Furthermore, the Department's standard for determining the public interest in evaluating gas company's contracts under Section 94A – focusing on consistency with the company's portfolio objectives and favorable comparison to the range of reasonably available alternative options – could likely be applied to contracts by EDCs with only minor adaptations.⁸

⁷ See Bay State Gas Company, D.P.U. 13-158 at p. 3.

⁸ See Commonwealth Gas Company, D.P.U. 94-174-A at 27.2.

2. Is there an alternative mechanism available for EDCs or other parties to secure new gas delivery capacity for the region?

ANGA appreciates the DOER and DPU's recognition of the need for additional natural gas delivery capacity in the region. As noted, it is crucial that the region establish new and expand existing means for natural gas delivery to reduce congestion and increase natural gas capacity available for electricity generation during peak demand periods. A key to adding gas delivery capacity is enabling generators to recover the cost of securing firm delivery. A market based mechanism could also be used to enable this cost recovery and the ensuing infrastructure growth. While we do not have a specific proposal, such market mechanism would require the Independent System Operator of New England (ISO-NE) to change its market rules to allow generators adequate cost recovery.

3. What would be the standard of review for such contracts?

Section 94A states that any gas or electric company contract for the purchase of gas must include a provision "subjecting the price to be paid thereunder for gas or electricity to review and determination by the [D]epartment." In the case of new gas delivery capacity contracts, the value of the contract is largely in the certainty of both price and fuel availability, which will mitigate the market price spikes seen in times of peak demand. As such, one would expect that the price paid for the contract might incorporate a premium in addition to the base commodity cost of natural gas. The DPU should clearly articulate the value of fuel and price certainty in establishing its standard of review. Furthermore, we note that Section 94A establishes a forward-looking review only, and urge the DPU to avoid setting any "lookback" provisions that could threaten an already-approved contract. A forward-looking review will appropriately balance the need for Department review and assessment with regulatory certainty for contracting parties that will be necessary to arrive at terms of these new contracts.

4. How should affiliate relationships among EDCs and potential bidders be addressed?

Affiliate relationships among EDCs and potential bidders could be addressed using standard treatment of similar affiliate relationships. Analogous affiliate relationships have arisen in the context of procurement of electricity from third party suppliers in states, such as Massachusetts, with retail choice. Typically the states have already-adopted procedures, such as transparent and nondiscriminatory auctions, to provide assurance that EDCs' affiliate contracts reflect competitive rates and terms. In addition, the Federal Energy Regulatory Commission (FERC) has similar standards for evaluating affiliate sales in electricity procurement (including those where EDCs procure wholesale power from their FERC-regulated affiliates). These standards require a demonstration that: (1) the EDC's solicitation was open and fair; (2) the product being procured was clearly defined; (3) standardized evaluation criteria were applied equally to all bids; and (4) an independent third-party administered and oversaw all stages of the solicitation.

These existing models should guide Massachusetts DPU's treatment of EDC affiliate relationships with potential bidders here. Because many states and EDCs are already familiar with state procedures and FERC's requirements, Massachusetts DPU should look to these

established processes as a potential model for dealing with affiliate relationships among EDCs and potential bidders in the pipeline capacity context.

5. What financial risk will be borne by ratepayers and EDCs? What mitigation tools are available to offset these risks?

Natural gas capacity contracts by EDCs will greatly reduce financial risks faced by ratepayers. The current model of natural gas distribution exposes ratepayers to high market spot prices in times of high demand or congestion. A longer-term contract for this delivery will secure supply and reduce volatility, providing a hedge against future spikes.

6. Since the effects of any capacity contracts would have a regional impact, should any approvals be conditioned upon some or all New England states sharing in the contracting obligation?

Regional natural gas reliability and cost issues will be most effectively addressed with the action and input of multiple states. However, we do not recommend establishing any barriers to single state action. This is an opportunity for Massachusetts to lead. The DPU, DOER, EDCs that span across multiple states, and other stakeholders should actively encourage other states to develop similar contracting programs, and, once active in Massachusetts, share lessons learned across state lines to continue program improvement. Of course, to the extent that an EDC contract would implicate operations in multiple states, that EDC must file appropriate requests for approval or notices in each state in order to meet relevant regulatory and statutory requirements; however, each state's process may proceed independently and should not be contingent upon any other state's decision(s).

7. How will the contracted-for capacity be made available to the market such that the benefits accrue to Massachusetts ratepayers?

Currently, electric sector natural gas costs are a "pass through" from EDCs to electric customers, meaning that ratepayers bear all costs of congestion or shortage-caused price spikes. Accordingly, as longer-term contracts for natural gas capacity mitigate these price spikes, ratepayers will automatically experience the benefits through lower, and more consistent, natural gas costs. On the issue of market availability of capacity, DPU should work with the ISO-NE, and potentially other affected regional grid operators, to target development and contracts in areas in which capacity is most needed.

8. Should there be a third party managing the sale of the capacity in the market?

When coupled with multi-party contracts, third party management can increase efficiency of regional coordination among multiple affiliated or unaffiliated natural gas suppliers and distributors. On April 16, 2015, FERC issued Order 809 with a Final Rule under Docket RM14-2, more commonly known as the gas-electric coordination docket.⁹ In the Order, FERC approved multi-party natural gas transportation contracts, which allow multiple (not necessarily affiliated) shippers the option of entering into a single contract for natural gas transportation service, with a single agent or asset manager managing the capacity under the contract. This

⁹ See 151 FERC ¶ 61,049. Available at <https://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf>.

allows several shippers to share natural gas capacity and to transfer the capacity among themselves, without the need to use the FERC's capacity release program, which could increase inefficiencies and make it more difficult to build and manage new capacity.¹⁰ FERC has approved multiple contracts of this nature already, and has noted that this may help increase "regional solutions... to address certain needs arising from increased use of natural gas."¹¹ Following this model, Massachusetts' EDCs could share a transportation contract that is managed by an independent third party, allowing for increased flexibility, consistency, and transparency.

9. If a contract is approved, how should costs be allocated in distribution rates?

As noted in response to Question 7, these contracts will intrinsically result in benefits that are automatically felt by ratepayers through the security of natural gas supply and reduction in natural gas price volatility. Specific ratemaking should be left to the EDC and DPU rate making processes.

Additional Questions

- 1. What specific natural gas delivery capacity constraints are causing high regional electricity prices? Please identify and characterize constraints with respect to geographic location, time of year, and/or market condition when constraint is or will be binding, and the degree to which the constraint impacts local versus regional natural gas delivery capability.**

ANGA is unaware of local constraints, such as a specific lateral line being inadequate to supply a power generator. Based on observations of New England's generation-driven constraints in recent years and studying earlier constraints (such as in 2004), ANGA understands that the large northbound trunklines of Tennessee Gas Pipeline Company (Tennessee and Algonquin Gas Transmission) become oversubscribed in times of high demand and thus constrain the entire region.

This is due primarily to a shift from historical supply sites. In the early 2000s, New England was served by the new Maritimes & Northeast Pipeline (Maritimes) between Nova Scotia to Boston, with gas primarily flowing from the north and offsetting any pressure on the large northbound lines of Tennessee and Algonquin. This configuration supported extensive growth in gas-fired power generation, without major expansions of the northbound pipelines. However, the supply from large offshore fields in areas such as Sable Island upon which Maritimes depended, did not materialize at the expected levels, leaving Maritimes undersupplied. There is now large, rapidly growing natural gas supply available from the south and west (in the nearby Marcellus and Utica shale plays), the current means to get that gas to New England is the northbound Tennessee and Algonquin pipelines, which were originally built to bring Texas and Louisiana gas to market. These pipelines must be expanded for the shale-driven abundance to reach market during constrained periods. For example, during the periods in January 2014 when spot prices across New England exceeded \$100 per million Btus, spot prices in Pennsylvania, in the heart of the Marcellus shale, averaged approximately \$4 per million Btu. This sort of massive price

¹⁰ See *id.* at pp. 90-91.

¹¹ *Id.* at p. 89.

difference is driven by constraints preventing natural gas from getting *into* New England, not distributing it *within* New England.

The constraints in New England primarily take place when normal winter heating loads combine with power generation loads and demand more capacity from the northbound pipelines than is available. In the past, gas-fired power generation ran in the summer much more than in the winter, so the two markets (for electricity and heating) were able to share the same pipeline capacity, with heating loads using it in the winter and generation using it in the summer. However, the past decade has seen growth in gas-fired power generation, and now gas-fired generation runs year-round.

2. What specific natural gas resources and/or commercial mechanisms could potentially alleviate each of the natural gas delivery capacity constraints identified above? What is the estimated cost and timing required to implement each potential resource/commercial mechanism?

There are four basic mechanisms for alleviating the mainline constraints in New England that are caused by gas-fired generators demanding pipeline capacity concurrent with heating market demand: (1) new pipeline capacity; (2) capacity releases from other firm shippers; (3) utilization of liquefied natural gas (LNG) capabilities; and (4) generator alternate fuel capability. We address each of these briefly below.

First, some level of new pipeline capacity is needed in the region, but the economics of additional capacity are most attractive if it is sized to be used at reasonable load factors or utilization levels. This appropriate size is best determined by the market and by the willingness of regional utilities and end-users to commit to the cost of the capacity. The high number of projects and the subscription levels of the projects underway in the Northeast should be seen as market confirmation that, at a minimum, their capacity is needed and more may be appropriate. For the shorter-term or less constant constraints, the other three basic mechanisms for alleviating constraints may make more sense. Capacity releases from firm shippers that are then purchased by generators in times of peak need can work if the original shipper has its own alternatives. An example would be a local gas distribution company using its own demand “peak-shaving” capability in lieu of its pipeline capacity, or curtailing its own alternate-fuel-capable interruptible customers, and then charging the generator picking up capacity a fee for the capacity release. LNG terminals, such as the GDF Suez receiving terminal in Everett, Massachusetts, provide a third mechanism. LNG terminals can feed the natural gas network from the East, thus alleviating the constraints in the northbound and eastbound pipelines. This mechanism has been increasingly used over the past year as LNG prices fell. This works well up to the Everett capacity, as long as the economics are attractive to keep the facility’s tanks full, and as long as there are not constraints too far west or north in the New England region. Other LNG terminals in the region may also be an option and need to evaluate their own economics.

Finally, alternate fuel capability for the generators themselves, usually oil, has an important place for very short-term constraints. This mechanism has the advantage of completely removing the generators from the competition for pipeline capacity, but it has three primary drawbacks: the generators must incur the cost of installing and keeping oil storage tanks full to meet uncertain

need; use of the alternate fuel must be carefully limited to stay within air-quality constraints; and in the event longer runs are needed and storage capacity is exceeded, the generators need to be resupplied with large amounts of light-distillate oil during mid-winter periods when prices are highest and delivery is most difficult. Other alternative options, such as on-site LNG storage for generators and LNG conversion along pipelines, are also being explored and may be attractive. Use on onsite LNG eliminates the air-quality constraints that arise from oil use. Like new pipeline capacity, alternate fuel capability and its on-site fuel storage must be carefully sized to find an optimal level.

The specific dollar cost of each of these options is best addressed by the pipelines, LNG providers, utilities and generators in New England region. ANGA expects there to be a great deal of variation in those costs.

- 3. What rules or standards should apply to any affiliate relationships among EDCs, potential bidders, and buyers of the natural gas capacity? Please respond with regard to relationships between EDCs and affiliates who are, or may potentially be, partners in interstate pipeline projects; and Address any other affiliate relationship conflicts not identified above that may affect the proposed contracts and bidding dynamic.**

As discussed in response to DOER Question 4 above, states with deregulated and/or market-based power supply typically have established procedures addressing EDCs' affiliate relationships in the context of EDCs procuring electricity, and FERC has similar standards for evaluating affiliate transactions. These procedures and those utilized by FERC in the context of multi-party agreements could serve as a potential model for dealing with a variety of affiliate relationships between EDCs and potential bidders, purchasers of natural gas capacity or other affiliate relationships that may arise.

- 4. Apart from issue pertaining to Section 94A, are there any legal impediments to the contractual and cost recovery arrangements discussed by DOER?**

We are not aware of any legal impediments to the arrangements discussed by DOER. The contractual structure DOER proposes would likely further several of the purposes of the Restructuring Act, including the long-term reduction of electricity rates, assurance of sufficient supply of electric generation, and improvement in public confidence in the electric utility industry.¹²

- 5. How will EDCs acquire natural gas capacity and how will the amount of new natural gas capacity for each EDC be determined?**

As discussed in response to Additional Question 1, the amount of new natural gas capacity needed is dependent on factors largely external to the Northeast region, such as constraints in long distance pipelines moving natural gas into the region. Additionally, as explained in response to Additional Question 2, EDCs and generators have multiple tools to address shortages, including increasing storage of LNG and new natural gas capacity. To determine how

¹² See 1997 Mass. Legis. Serv. Ch. 164 § 1.

much capacity is needed, EDCs and other affected parties should work with entities conducting local and regional planning processes, often the local energy market operators and regional grid manager (e.g., ISO-NE), who are best able to assess external factors influencing regional constraints and identify the most appropriate and cost-effective approach for adding capacity. Once need is determined, EDCs can participate in FERC-reviewed solicitations. This may include solicitations for new pipeline capacity. Because a contract for new natural gas capacity could have wide-ranging impacts on local and regional natural gas markets and prices, EDCs may wish to consider multi-party contracts in which multiple EDCs or providers coordinate to best serve their joint needs.

6. How will EDCs determine the length of contracts for natural gas capacity?

An EDC will need to determine the specific length of contract that will best manage its customers' costs and serve its reliability needs. However, we note that there is a minimum duration that most pipe developers will require in order to be assured of recovering their fixed construction, operation and maintenance, and other costs. This minimum length will vary based on factors such as cost of construction (which is highly dependent on both location and length), projected operating revenues and costs, and regulatory certainty around commitment to natural gas as a crucial reliability maintenance tool and baseload resource.

7. How will EDCs release or otherwise sell the natural gas capacity?

EDCs' capacity release should be in compliance with FERC rules, which call for non-discriminatory access to capacity and generally require that released capacity be publicly posted and awarded to the highest bidder.¹³ There are, however, exceptions to FERC's general public posting rule, including an exception for capacity release to marketers participating in state-regulated retail access programs.¹⁴ Given that FERC has previously shown flexibility in its capacity release rules to facilitate state programs such as retail access, it is possible that FERC would entertain specific rules to facilitate Massachusetts' chosen mechanism for securing new gas delivery capacity into the region. Massachusetts could make such a request to FERC by submitting a petition explaining that such capacity would be procured by the state for a specific purpose and should not be subject to the general capacity release public posting requirements.

8. Could there be restrictions placed on the release of natural gas capacity so that the released capacity only can be acquired by electric generators serving the ISO New England market?

As discussed above in response to Additional Question 7, FERC generally requires released capacity to be publicly posted and awarded to the highest bidder on a non-discriminatory basis, and FERC's approval would be required to depart from these capacity release rules in order to restrict capacity release only to electric generators serving the ISO-NE market. Restricting capacity release only to generators serving that market also narrows the pool of generators from which natural gas capacity costs could be recovered. A better approach might be to give generators serving the ISO-NE market a priority to released capacity, while allowing unused capacity to be sold to generators outside the ISO-NE market. This approach would still likely

¹³ See 18 C.F.R. § 284.8(c)-(e).

¹⁴ See *id.* § 284.8(h)(1)(ii).

require permission from FERC but would permit a more efficient use of released capacity and may provide a broader set of generators from which natural gas capacity costs could be recovered.

9. Please indicate the types of natural gas capacity that the EDCs would acquire.

As addressed in previous responses, an EDC should determine the best natural gas capacity option for its customers through a coordinated planning process. DPU should ensure that its standards and processes allow for all cost-effective and reasonable options, including new natural gas pipeline, natural gas storage facilities, and LNG infrastructure.

10. If a contract is approved, will total contract costs collected from ratepayers be capped at a specific amount or threshold? Ifs, at what level should the cap be set? Over what time period will EDCs collect total contract costs through rates?

Contracts signed between EDCs and pipelines should be treated like any other operating cost—recovered concurrently as they are paid to the pipelines. The pipeline rates are and will be reviewed and approved by the FERC, so the same doctrine that allows full flow-through of these costs by local gas distribution companies should apply here. As with all contracts, DPU (and, if jurisdictional, FERC) will review the contracts upon signing for prudence and along existing and appropriate standards, but thereafter, the utility should be entitled to recover its contract payments, net of release contributions from generators.

11. Should EDCs collect costs through base distribution rates or through a separate reconciling mechanism? Discuss the benefits and disadvantages of each approach.

ANGA supports developing a separate reconciling mechanism for EDCs to collect their costs. Such a mechanism, which may be similar to a purchased-gas adjustment or purchased-power adjustment, would allow changes in pipeline rates to be reflected as they occur (both upward and downward). It would similarly allow a reflection of the actual level of generator activity as it occurs. This assures customers that the utility is recovering exactly the amount it spends on this new capacity (net of generator revenues), and no more.

12. If the Department approves the costs, will the costs collected from ratepayers include only the costs of the contract, or will total costs include administrative costs associated with managing the contracts?

ANGA does not have a response to this question at this time, but reserves the right to provide comments on this issue on response.

13. If the Department approves the costs, will the costs collected from ratepayers include only the costs of the contract, or will total costs include administrative costs associated with managing the contracts?

The third party can recover costs as an administrative fee when they administer the program, thus making the release program self-funded.

14. How are future changes in the gas market to be addressed if the EDC contract proposal is implemented? Specifically, is this mechanism designed to be a permanent or interim measure? How is this mechanism to be re-evaluated if energy alternatives are successful?

As energy alternatives continue to develop, the DPU should continue to evaluate this mechanism to be sure it appropriately incentivizes natural gas capacity. In the medium term, natural gas will only be increasingly important as a tool to replace retiring baseload units and integrate alternative sources of energy such as renewables.

However, any changes to the contracting measure should in no way affect executed contracts (unless those contracts included a provision for such reassessment). Medium- and long-term contracts will only result in the stability needed to develop new infrastructure insofar as they are certain to operate per agreed-upon terms until completion. Parties to a contract may renegotiate and amend the contract per its terms if both parties agree, but the DPU should not have any “look back” jurisdiction to amend or cancel executed contracts.

15. Are there regions or states with existing financial structures/regulations in place for electric distribution companies to contract for firm natural gas capacity? Please provide any information on how these regions or states implement and manage these contract arrangements.

ANGA is not aware of any existing structures or regulation of this kind.

16. If EDCs contract for new natural gas delivery capacity, how should they manage the capacity to best achieve policy objectives of making such capacity available for electricity generators and reducing electricity market costs for Massachusetts distribution ratepayers? How should the benefits associated with any such contracts be measured? How can the value embedded in any such contracts be monetized and captured for Massachusetts ratepayers?

Natural gas capacity contracts by EDCs will greatly reduce financial risks faced by ratepayers. The current model of natural gas distribution exposes ratepayers to high market spot prices in times of high demand or congestion. A longer-term contract for this delivery will secure supply and reduce volatility, providing a hedge against future spikes.

The value embedded in these contracts will be intrinsic in their mitigation financial and supply risk. These benefits could be measured over a reasonable timeframe by comparing the incidence, duration, and severity of supply constraints and elevated prices after contracts for additional capacity are effective to the incidence, duration, and severity of supply constraints and elevated prices experienced prior to this investigation.