REDACTED

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for Approval of Firm Gas Transportation and Storage Agreements with Algonquin Gas Transmission Company, LLC, pursuant to G.L. c. 164, § 94A	)	D.P.U. 16-05

Direct Testimony of Elizabeth A. Stanton

On Behalf of Conservation Law Foundation

Regarding Consistency of Petition with State and Federal Environmental Policies and Energy Forecasting Principles

June 20, 2016

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Elizabeth A. Stanton, and I am a Principal Economist with Synapse Energy Economics at 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have more than 15 years of professional experience as an environmental economist. At Synapse, I have led studies examining environmental regulation, cost-benefit analyses, and the economics of energy efficiency and renewable energy. I have submitted expert testimony in Massachusetts, Vermont, New Hampshire, Illinois, and several federal dockets; and I have authored more than 100 reports, policy studies, white papers, journal articles, and book chapters on topics related to energy, the economy, and the environment.

Prior to joining Synapse, I was a Senior Economist with the Stockholm

Environment Institute's (SEI's) Climate Economics Group, where I was responsible for leading the organization's work on the Consumption-Based Emissions Inventory (CBEI) model and on water issues and climate change in the western United States. While at SEI, I led domestic and international studies commissioned by the United Nations Development Programme, Friends of the Earth-U.K., and Environmental Defense.

My articles have been published in *Ecological Economics*, *Renewable Resources Journal*, *Environmental Science & Technology*, and other journals. I have also published books, including *Climate Economics: The State of the Art* (Routledge, 2013), which I co-wrote with my colleague at Synapse, Dr. Frank Ackerman. I am also coauthor of *Environment for the People* (Political Economy Research Institute, 2005, with James K. Boyce) and coeditor of *Reclaiming Nature: Worldwide Strategies for Building Natural Assets* (Anthem Press, 2007, with Boyce and Sunita Narain).

I earned my Ph.D. in economics at the University of Massachusetts-Amherst, and have taught economics at Tufts University, the University of Massachusetts-Amherst, and the College of New Rochelle, among others. My curriculum vitae is attached as Exhibit CLF-EAS-2.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Conservation Law Foundation.

Q. Have you testified previously in this docket?

A. No, I have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an independent, third-party review of the modeling results of scenarios of New England's future electric sector with and without the Access Northeast (ANE) pipeline submitted by the petitioner as Exhibit NG-JNC-3. In particular, I have reviewed these modeling results to assess whether or not the petitioner's modeling assumptions are (1) consistent with compliance with state and federal environmental laws; and (2) represent "most likely" projections of uncertain future conditions.

I found that:

(1) The petitioner's modeling results do not appear to include assumptions necessary to represent all current laws and regulations. In the petitioner's modeling results:

- Massachusetts relies on unexplained emission reductions in the other Regional Greenhouse Gas Initiative (RGGI) states to achieve its own compliance with RGGI.
- Massachusetts' electric sector emissions are in line with the expectations in the 2015 Update to the Clean Energy and Climate Plan for 2020 (CECP), but subsequently increase and are higher than this 2020 target in years 2022 through 2040.
- Massachusetts' generators regulated under the Clean Power Plan emit more carbon dioxide (CO_2) than allowed for under the state's cap—again, requiring its excess emissions to be balanced by extra emission reductions in other states to achieve compliance.
- Massachusetts does not appear to comply with its Renewable Portfolio Standard (RPS).
- New England states—including Massachusetts—do not appear to achieve the level of energy efficiency modeled by ISO-NE in its 2016 CELT electric demand forecast.
- New England's electric imports are not consistent with the level of new hydroelectric imports called for by Governor Baker as necessary to comply with the Global Warming Solutions Act (GWSA).

(2) The modeling results submitted by the petitioner appear to use artificially high seasonal and annual natural gas prices in the petitioner's No Pipeline "Base

Case", exaggerating the likely net benefits associated with the construction and operation of the ANE.

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Qualifications.
2. The Petitioner's Modeled Scenarios Do Not Comply with Greenhouse Gas Emissions Regulations, With or Without the ANE Pipeline.
3. Benefits Reported by the Petitioner are Based on Out-Dated Assumptions Regarding Gas and Electric Prices.
4. Key Alternative Resources to Natural Gas are Omitted From the Petitioner's Modeling Results.
5. The Petitioner's Modeling Results Do Not Accurately Portray Expected Future Conditions in Massachusetts.

2. THE PETITIONER'S MODELED SCENARIOS DO NOT COMPLY WITH GREENHOUSE GAS EMISSION REGULATIONS, WITH OR WITHOUT THE ANE PIPELINE.

Q. What is the Regional Greenhouse Gas Initiative?

A. RGGI is a market-based CO_2 cap and trade program designed to reduce CO_2 emissions within nine northeastern states: Connecticut, Delaware, Maine, Massachusetts, Maryland, New Hampshire, New York, Rhode Island, and Vermont. Since 2009, power plants located in RGGI states have been required to purchase allowances to permit their emissions of CO_2. Allowances are auctioned quarterly with the revenues returning to the participating states. In 2014, RGGI states agreed to reduce the cap on their emissions significantly to better correspond with current dispatch of electric resources.

Q. Are CO_2-emitting power plants in the Commonwealth of Massachusetts obligated to purchase RGGI allowances?

A. Yes. Chapter 169 of the Massachusetts Green Communities Act requires Massachusetts' power plants to comply with the rules and regulations of RGGI and permits them to engage in regional trading of emission allowances.

Q. In the modeling results submitted by the petitioner are total emissions for all RGGI states below the RGGI emissions cap?

A. The petitioner has not provided sufficient information to determine whether emissions from all nine states are below the RGGI emissions cap. CO_2 emissions for non-New England RGGI states (Delaware, Maryland, and New York) are not provided in Black & Veatch's modeling results. As a result, I cannot confirm that the nine-state region complies with its annual emission caps in any of the study period. In this testimony, I implicitly calculate emissions for these three states by assuming the nine state region does not exceed its total cap, and by subtracting the emissions reported for the six New England states from this total.

Q. Is assuring regional compliance with the regional cap adequate to correctly model Massachusetts's RGGI compliance?

A. Keeping the CO_2 emissions of the RGGI region's generators below the regional cap is necessary to adequately model compliance with RGGI, but it may not be sufficient. The distribution of emissions among the RGGI states is also important. Since the 2014 revision of the RGGI emission caps, Massachusetts generators' share of regional emissions has been well below its share of allowances issued for auction. As explained in detail below, in the modeling results provided in Attachment NEER 1-1(b) and Attachment NEER 1-1(c) —both with and without the ANE pipeline, Massachusetts' generators take on a greater share of allowance purchases in future years while the non-New England RGGI states' generators exhibit an unexplained decline in emissions and allowance purchases.

Q. In the modeling scenarios submitted by the petitioner, how do Massachusetts' generators CO_2 emissions compare with the share of the RGGI allowances allocated to Massachusetts?

A. Massachusetts CO_2 emissions are higher than the state's share of the RGGI allowances in all modeled years for both Black & Veatch's No Pipeline "Base Case" and the With ANE Only cases. Figure 1 depicts emissions from Massachusetts generators in the two modeling cases presented in the Black & Veatch report for the petitioner (Exhibit NG-JNC-3) along with the state's share of the RGGI allowances (see Exhibit CLF-EAS-3, sheet "RGGI_Comparison").

Figure 1. Massachusetts electric-sector CO_2 emissions: Black & Veatch scenarios and state share of RGGI allowance allocation

Sources: Attachment NEER 1-1(b); Attachment NEER 1-1(c); RGGI Allowance Allocation Documents submitted as Exhibit CLF-EAS-3, sheet "RGGI_Allowances".

Notes: RGGI allowances decline by 2.5 percent per year from 2015 to 2020, and are assumed to remain constant thereafter; effective state-level RGGI allowances are assumed to remain at each state's current proportion of total RGGI emissions in future years.

Q. In the modeled scenarios submitted by the petitioner, how do the rest of New England's generators' CO_2 emissions compare with the share of RGGI allowances allocated to the rest of New England?

A. The rest of New England CO_2 emissions are higher than these states' combined share of RGGI allowances in all modeled years in Black & Veatch's No Pipeline case. In all but two years (2034 and 2040), the rest of New England CO_2 emissions are higher than these states' combined share of RGGI allowances in Black & Veatch's With ANE Only case. In the With ANE Only case, 2034 and 2040 emissions are just [redacted] percent below the combined five-state share of allowances. Figure 2 depicts emissions from Connecticut, New Hampshire, Maine, Rhode Island, and Vermont generators in the modeling presented in the Black & Veatch report for the petitioner (Exhibit NG-JNC-3) along with the sum of those states' shares RGGI of allowances (see Exhibit CLF-EAS-3, sheet "RGGI_Comparison").

Figure 2. Rest of New England electric-sector CO_2 emissions: Black & Veatch scenarios and rest of New England share of RGGI allowance allocation

Sources: Attachment NEER 1-1(b); Attachment NEER 1-1(c); RGGI Allowance Allocation Documents submitted as Exhibit CLF-EAS-3, sheet "RGGI_Allowances".

Notes: RGGI allowances decline by 2.5 percent per year from 2015 to 2020 and are assumed to remain *constant thereafter; effective state-level RGGI allowances are assumed to remain at each state's current proportion of total RGGI emissions in future years.*

Q. In the modeled scenarios submitted by the petitioner, how do Delaware, Maryland, and New York's generators' CO_2 emissions compare with the share of the RGGI allowances allocated to Delaware, Maryland, and New York?

A. In contrast to Massachusetts and the rest of New England's CO_2 emissions (which are higher than their share of the RGGI allowances), the three non-New England states' emissions are lower than their share of the RGGI allowances in Black & Veatch's modeled scenarios. Figure 3 depicts calculated emissions from Delaware, Maryland, and New York generators in the modeling presented in the Black & Veatch report for the petitioner (Exhibit NG-JNC-3; these states' emissions are inferred as the difference between total RGGI emissions in the petitioner's response to CLF-1-5 and New England emissions in Attachment NEER 1-1(b) and Attachment NEER 1-1(c)) (see Exhibit CLF-EAS-3, sheet "RGGI_Comparison"). Delaware, Maryland, and New York's CO_2 emissions are lower than these states' combined share of RGGI allowances in every year between 2018 and 2040 in both the No Pipeline and the With ANE Only cases.

Figure 3. Delaware, Maryland and New York electric-sector CO_2 emissions: Black & Veatch scenarios and Delaware, Maryland and New York share of RGGI allowances allocation (note change in y-axis scale from previous two figures)

Sources: Attachment NEER 1-1(b); Attachment NEER 1-1(c); RGGI Allowance Allocation Documents submitted as Exhibit CLF-EAS-3, sheet "RGGI_Allowances".

Notes: RGGI caps decline by 2.5 percent per year from 2015 to 2020, and are assumed to remain constant thereafter; effective state-level RGGI allowances are assumed to remain at each state's current proportion of total RGGI emissions in future years; Non-New England ("Non-NE") RGGI emissions are calculated by subtracting the emissions from the six New England states in Attachment NEER 1-1(b) and Attachment NEER 1-1(c) from the total emissions for all RGGI states.

Q. In the modeled scenarios submitted by the petitioner, by how much do Massachusetts generators' CO_2 emissions exceed the share of the RGGI allowances allocated to Massachusetts?

A. The emissions from Massachusetts' generators in Black & Veatch's modeled scenarios exceed Massachusetts' allocation of RGGI allowances by a range of [redacted] short tons in 2020 and a range of [redacted] short tons in 2040 in the No Pipeline and the With ANE Only cases, respectively. To be clear, Black & Veatch modeled emissions exceed Massachusetts' share of RGGI allowances with or without the pipeline (see Exhibit CLF-EAS-3, Sheet "RGGI_Comparison").

Q. Do the modeling results submitted by the petitioner appropriately model Massachusetts generators' RGGI compliance?

A. No. As shown in Figure 4, in Black & Veatch's No Pipeline and With ANE Only cases Massachusetts emissions as a share of the state's allocated allowances grows while that of the rest of the RGGI region shrinks. In 2015, Massachusetts generators emitted just 87 percent of the emissions allotted to Massachusetts. In 2019, Black & Veatch models Massachusetts generators emitting [redacted] percent of their allotted emissions (see Exhibit CLF-EAS-3, Sheet "RGGI_Allowances"). By 2040, this value grows to [redacted] to [redacted] percent of their allotted emissions.

Figure 4. Massachusetts and rest of RGGI CO_2 emissions as a share of their allowance allocation

Sources: Attachment NEER 1-1(b); Attachment NEER 1-1(c); RGGI Allowance Allocation Documents submitted as Exhibit CLF-EAS-3, sheet "RGGI_Allowances".

Note: Solid lines represent the "No Pipeline" case, whereas dashed lines indicate the "With ANE" case. Non-Massachusetts ("Rest of RGGI") emissions are calculated by subtracting the emissions from Massachusetts in Attachment NEER 1-1 (b) and Attachment NEER 1-1(c) from the total emissions for all RGGI states.

Q. Does Massachusetts' compliance with RGGI depend on the dispatch of generators in other states?

A. Yes. In the scenarios modeled by Black & Veatch, Massachusetts generators' compliance with RGGI depends on the rest of the RGGI region—and, in particular, Delaware, Maryland, and New York—buying a much smaller share of total allowances than they have in the past. In 2015, in RGGI states other than Massachusetts, generators emitted 97 percent of the emissions allotted to them. In 2019, Black & Veatch models generators in RGGI states other than Massachusetts emitting just [redacted] to [redacted] percent of their allotted emissions (See Exhibit CLF-EAS-3, sheet "RGGI_Allowances".) By 2040, however, this value shrinks to [redacted] to [redacted] percent of their allotted emissions.

Q. What explanation of the change in balance of RGGI emissions between Massachusetts and the rest of the RGGI states does the petitioner offer?

A. The change in generation and emissions in the rest of the RGGI states—and, in particular, Delaware, Maryland, and New York— is not explained in Exhibit NG-JNC-3. In National Grid's response to CLF-1-6, the petitioner explains (in response to a question about New York state RPS requirements) that "Black & Veatch's responses are limited to the New England area given the limited relevance of information regarding power markets outside of New England." The petitioner does not state that Delaware, Maryland, and New York were not modeled in Black & Veatch's analysis (Exhibit NG-JNC-3). Rather, the petitioner claims that the modeling results for these states need not be submitted because they are—the petitioner asserts—irrelevant.

The modeled generation and emissions of Delaware, Maryland, and New York have been withheld by the petitioner in this docket but nonetheless appear to be very relevant indeed to the assumptions that are making it possible for the petitioner to claim that "All cases considered for this analysis remain below RGGI's published caps." (See National Grid's response to CLF 1-5.) Even if the emissions of the nine-state region as a whole do not exceed the RGGI cap, this emission limit is maintained in Black & Veatch's modeled cases by balancing increases in Massachusetts' emissions with unexplained decreases in the emissions of other states.

Q. What is the Global Warming Solutions Act?

A. The Massachusetts Global Warming Solutions Act (GWSA) was enacted in 2008 with the goal of reducing the Commonwealth's greenhouse gas emissions. GWSA set a state-wide greenhouse gas emissions limit of 80 percent below 1990 emissions levels by 2050, and required the Department of Environmental Protection to set interim targets. In 2010, the Secretary for Energy and Environmental Affairs established a legally binding statewide greenhouse gas emissions limit of 25 percent below statewide 1990 emissions by 2020 and subsequently published the *Massachusetts Clean Energy and Climate Plan for 2020* (CECP), describing a portfolio of policies aimed at enabling the Commonwealth to achieve its 2020 statewide emissions reduction target of 25 percent below statewide 1990 emissions.

The Massachusetts Supreme Judicial Court's May 17, 2016 decision in *Kain v. Department of Environmental Protection* upholds the emission limit mandate set in GWSA and the obligation of the state to regulate annual emission limit targets by emissions category consistent with achieving an overall 25 percent emission reduction by 2020.

Q. What emission reductions are expected from the Commonwealth's electric sector under GWSA?

A. A 2015 Update to the CECP calls for electric-sector CO_2 emissions to drop to a level between 11 and 14 MMT by 2020 (see Exhibit CLF-EAS-4 and Exhibit CLF-EAS-3, page "GWSA_Comparison").

Q. Do the emissions modeled by the petitioner correspond to the level of emissions reductions expected for the Massachusetts electric sector in the 2015 Update to the CECP?

A. As depicted in Figure 5, 2020 emissions in Black & Veatch's No Pipeline and With ANE Only cases are at the high end of the range stated in the 2015 Update to the CECP (see Exhibit CLF-EAS-4 and Exhibit CLF-EAS-3, sheet "GWSA_Comparison"). (Note that in Figure 5 the CECP electric-sector target is presented in short tons to be consistent with the Black & Veatch modeling, which is reported in pounds (lbs) (see Attachment NEER 1-1(b) and Attachment NEER 1-1(c)).

Figure 5. Massachusetts electric-sector CO_2 emissions: Black & Veatch scenarios and GWSA targets

Sources: Attachment NEER 1-1(b); Attachment NEER 1-1(c); 2015 Update to the CECP (Exhibit CLF-EAS-4).

Notes: Estimate of Massachusetts electric sector emissions target reflects range of potential electricity sector emissions targets, as derived from the 2015 Update to the CECP (Exhibit CLF-EAS-4). The 2015 Update to the CECP presents target greenhouse gas emissions reduction from electricity consumption is 14.2 to 17.2 MMT below 1990 emissions or 50 to 93 percent of total all-sector emission reductions from 1990. Assuming a 53 percent target in all-sector emission reductions in 2040 (using a linear trend between the 2020 and 2050 targets), the target total all-sector emissions target for 2040 is 36.2 MMT. If the annual rate of emissions reductions from the electricity sector assumed by CECP in 2020 (with a range of emissions reduction shares of 50 to 93 percent in 2020) is maintained through 2040, residual emissions from electric consumption would reach 0 MMT in 2038 (see Exhibit CLF-EAS-3, sheet "GWSA_Comparison").

Q. Do the emissions modeled by the petitioner correspond to the level of emission reductions expected for the Massachusetts electric sector for 2040?

A. Massachusetts' Secretary for Energy and Environmental Affairs has not yet set specific emission reduction targets for years in between 2020 and 2050. Governor Baker in 2015 signed the Resolution Concerning Climate Change at the 39th Annual Conference of New England Governors and Eastern Canadian Premiers adopting a range of at least 35 percent to 45 percent reduction below 1990 levels by 2030. The GWSA states that 2030 emissions limit must be set to "maximize the ability of the commonwealth to meet the 2050 emissions limit" (Section 3a) of a reduction of 80 percent from 1990 levels. In Figure 5 CECP emissions targets for years after 2020 are based on a linear interpolation of all-sector emission targets for years between 2020 and 2050 and the assumption that the electric sector would continue to contribute the same share of all-sector emissions reductions that it does in 2020 in the 2015 Update to the CECP (see Exhibit CLF-EAS-4 and Exhibit CLF-EAS-3, sheet "GWSA_Comparison").

Massachusetts electric sector emissions are [redacted] million short tons in 2040 in both the No Pipeline and With ANE Only cases. These emission levels are higher even than 2020 target of 12 to 15 million short tons, and far exceed the zero CO_2 emission target inferred for 2040.

Q. Do the modeling results submitted by the petitioner appropriately model Massachusetts compliance?

A. No. In years after 2020 in Black & Veatch's modeled results electric sector emissions increase over time. While no precise emission reduction target has as yet been established for the post 2020 time period, it would be difficult to argue that increasing emissions in any economic sector would be consistent with the directive to "maximize the ability of the commonwealth to meet the 2050 emissions limit".

Q. Did the Supreme Judicial Court's *Kain* decision affect or change your GWSA analysis for this case?

A. No. I have read the opinion of the Supreme Judicial Court in *Kain v. Department of Environmental Protection*. In my opinion as an economic expert, the *Kain* decision clarified the scope and effect of the GWSA on the future of the electric sector in Massachusetts. Specifically, the decision appears to reiterate that the GWSA's emissions reduction targets are strict standards that must be met, not aspirational or vague goals.

Q. What is the Clean Power Plan?

A. The Clean Power Plan is the U.S. Environmental Protection Agency's 2015 regulation of CO_2 emissions from existing power plants under section 111(d) of the Clean Air Act. The Clean Power Plan requires reductions of 32 percent below 2005 CO_2 emissions nationwide at levels by 2030 and reductions of 54 percent below 2005 CO_2 emissions in Massachusetts. In February 2016, the U.S. Supreme Court stayed implementation of the Clean Power Plan while litigation against the rule proceeds. Massachusetts has, however, joined with 14 other states to issue the following statement:

> *We are confident that once the courts have fully reviewed the merits of the Clean Power Plan, it will be upheld as lawful under the Clean Air Act. Our coalition of states and local governments will continue to vigorously defend the Clean Power Plan —which is critical to ensuring that necessary progress is made in confronting climate change. (Exhibit CLF-EAS-5).*

Q. Is Massachusetts required to take actions to comply with the Clean Power Plan?

A. Yes. All states with existing fossil fuel power plants are required to submit plans describing how they will comply with the rule in the future and to demonstrate that their actual CO_2 emissions are lower than or equal to state-specific rates or emission caps in 2022 through 2030. Massachusetts has one of the more stringent state-level CO_2 reduction requirements: CO_2 emissions must be 54 percent below 2005 levels by the year 2030. Over the entire compliance period, Massachusetts must reduce regulated electric sector CO_2 emissions from 13 million short tons in

2022 to 12 million short tons in 2030.

Q. In the scenarios of future generation with and without the pipeline submitted by the petitioner are Massachusetts CO_2 emissions below the state's Clean Power Plan emissions cap?

A. No. As shown in Figure 6, in the Black & Veatch No Pipeline and With ANE Only cases, Massachusetts in-state emissions from electric generation are greater than the mass-based translation of the state's emission-rate target (including an adjustment for expected new power plants) in all compliance periods (see Exhibit CLF-EAS-3, sheet "CPP_Comparison"). Massachusetts is not compliant with the Clean Power Plan in either of Black & Veatch's scenarios.

Figure 6. Massachusetts Clean Power Plan-Regulated CO_2 emissions: Black & Veatch scenarios and EPA targets

Sources: Attachment NEER 1-1(b); Attachment NEER 1-1(c); EPA Clean Power Plan detail submitted as Exhibit CLF-EAS-3, sheet "CPP_Goals".

Notes: Clean Power Plan-regulated CO_2 Emissions in Black & Veatch scenarios include emissions from all units with prime mover status of "Coal", "Combined Cycle", or "Oil/Gas"; Clean Power Plan caps shown here are mass-based standards, with new source complement.

Q. Could Massachusetts nonetheless comply with the Clean Power Plan, despite exceeding its emission targets?

A. To comply with the Clean Power Plan despite its in-state emissions from regulated generation exceeding its emission targets Massachusetts would have to both:

(1) Join with other states in an agreement to trade Clean Power Plan emissions allowances or rate credits, and/or otherwise secure trading partners; and

(2) Rely on greater emission reductions in other states to balance out excess emissions in Massachusetts.

Q. Do the modeling results submitted by the petitioner appropriately model Massachusetts compliance?

A. No. In all years, Massachusetts fails to comply with the Clean Power Plan in both of Black & Veatch's modeled scenarios.

Q. Does Massachusetts comply with regional, state, and federal greenhouse gas emission regulations in the modeled cases of future generation submitted by the Petitioner?

A. No. In Black & Veatch's No Pipeline and With ANE Only cases:

- Massachusetts relies on unexplained emission reductions in the other RGGI states to achieve its own compliance with RGGI.
- Massachusetts' electric sector emissions are in line with the expectations in the 2015 Update to the CECP for 2020 (Exhibit CLF-EAS-4), but subsequently increase and are higher than this 2020 target in years 2022 through 2040.
- Massachusetts' generators regulated under the Clean Power Plan emit more CO_2 than allowed for under the state's cap—again, requiring its excess emissions to be balanced by extra emission reductions in other states to achieve compliance.

Q. Has the petitioner submitted modeling results useful to a determination of whether or not a new natural gas pipeline is consistent with the environmental laws and policies of Massachusetts?

A. No. The modeling results submitted by the petitioner either do not comply with state and federal laws or require unexplained emission reductions in other states in order to achieve compliance.

3. BENEFITS REPORTED BY THE PETITIONER ARE BASED ON OUT-DATED ASSUMPTIONS REGARDING GAS AND ELECTRIC PRICES.

Q. What benefits does the petitioner attribute to building and operating the ANE pipeline?

A. The petitioner's initial petition states that: "On an aggregate basis, the Access Northeast project alone, as proposed, is projected to yield $1.1 billion in levelized annual net benefits for New England electric customers from 2019 through 2038 under normal weather conditions. Approximately 46.1% of the benefits will accrue to consumers in Massachusetts." (p.5). This estimate is based on a report by Black & Veatch International filed in this docket as Exhibit NG-JNC-3 and includes both the difference in electric system costs between scenarios of the future electric system without a new pipeline and with the ANE pipeline as well as the cost of constructing the pipeline.

Q. What are electric system costs and electric market benefits?

A. The electric system costs modeled by Black & Veatch are the product of the wholesale price of electricity in each time period modeled and the wholesale demand for (and delivery of) electricity in each time period modeled. In Exhibit-NG-JNC-3, Black & Veatch refers to the difference between the electric system costs in its No Pipeline and With ANE Only scenarios as "electric market benefits".

Q. What savings in electric market benefits does the petitioner expect from the ANE pipeline?

A. Black & Veatch asserts that the Access Northeast project would result in [redacted] "in annual levelized electric consumer benefit over the contract length," from 2019 to 2038; the petitioner's estimate of benefits does not include their modeled results for 2039 and 2040. See Exhibit NG-JNC-3 at p.25, Table 3. This estimate of benefits does not include the costs of constructing the pipeline. If these construction costs of [redacted] were taken into account, the net benefit of the pipeline in annual levelized terms would be [redacted].

Q. Do the petitioner's with and without pipeline scenarios both assume the same level of electric demand?

A. Yes. Black & Veatch's No Pipeline and With ANE Only scenarios (Exhibit NG-JNC-3) have the same electric demand (see Attachment NEER 1-1(f) and Exhibit CLF-EAS-3, sheet "Load_Summary").

Q. What is the source of the electric market benefits reported by the petitioner from the ANE pipeline?

A. The electric market benefits modeled in Black & Veatch's Exhibit NG-JNC-3 result from differences in the wholesale price of electricity between the No Pipeline and With ANE Only cases as illustrated in Figure 7 (see Exhibit CLF-EAS-3, sheet "LMP_Monthly"). More specifically the modeled electric market benefits are the result of a reduction in electric "price spikes" in winter months; outside of the winter (that is, in April through October) monthly wholesale electric prices are very similar between the two cases: these prices range from 5 percent <u>higher</u> to [redacted] percent lower in the With ANE Only case than they are in the No Pipeline in all modeled years. In contrast, in the winter month with the highest price, the With ANE Only case monthly wholesale electric prices are [redacted] to [redacted] percent lower than they are in the No Pipeline. The prices differences between the two cases—multiplied by the same electric demand—add up to Black & Veatch's [redacted] in electric market benefits from the ANE pipeline. Note that Black &

Veatch modeled 2039 and 2040 but did not report electric prices for these years.

Figure 7. Monthly historical wholesale electricity prices and Black & Veatch projections of future wholesale electricity prices in the No Pipeline and With ANE Only cases

Sources: Attachment NEER 1-1(a); ISO-NE monthly LMP data (available at http://www.iso-ne.com/static-assets/documents/markets/hstdata/znl_info/monthly/smd_monthly.xls submitted as Exhibit CLF-EAS-3, sheet "LMP_Monthly")

Notes: Actual wholesale electricity prices based on locational marginal prices (LMPs) at the ISO-NE hub. LMPs used from Black & Veatch's modeling are for Western Massachusetts (WMA). The shaded area labels as "claimed benefit" is illustrative and does not exactly represent the stated benefits of the ANE pipeline by Black & Veatch.

Q. How do the wholesale electric price spikes in the modeling results submitted by the petitioner relate to historical price spikes in New England?

A. With the exception of three winters (2012/2013, 2013/2014, and 2014/2015) the highest monthly wholesale electric price has been 14 to 51 percent higher than the average price in each year (April to March) since 2003 (see Exhibit CLF-EAS-3, sheet "LMP_Monthly").

In years 2012/2013, 2013/2014, and 2014/2015 wholesale electric prices spiked at levels that were anomalously higher than in years before or since: the highest monthly wholesale electric price was 137 to 170 percent higher than those years' average prices. In 2015/2016, the highest monthly electric price was just 34 percent higher than that year's average price.

In comparison, as shown in Figure 8 in Black & Veatch's No Pipeline case, on average across the modeled years, the highest monthly wholesale electric price is [redacted] percent higher than the average price in each year (where the yearly average is based on the year of data modeled and so may vary in the starting month). In comparison, in historical years other than 2012-2015, the highest monthly wholesale electric price is just 37 percent higher than the average price. The unexplained increase in prices in the No Pipeline case appears to largely drive the petitioner's benefits of implementing a pipeline.

Figure 8. Peak monthly wholesale electric price as a percentage of annual average: historical and Black & Veatch scenarios

Sources: Attachment NEER 1-1(a); ISO-NE monthly LMP data (available at http://www.iso-ne.com/static-

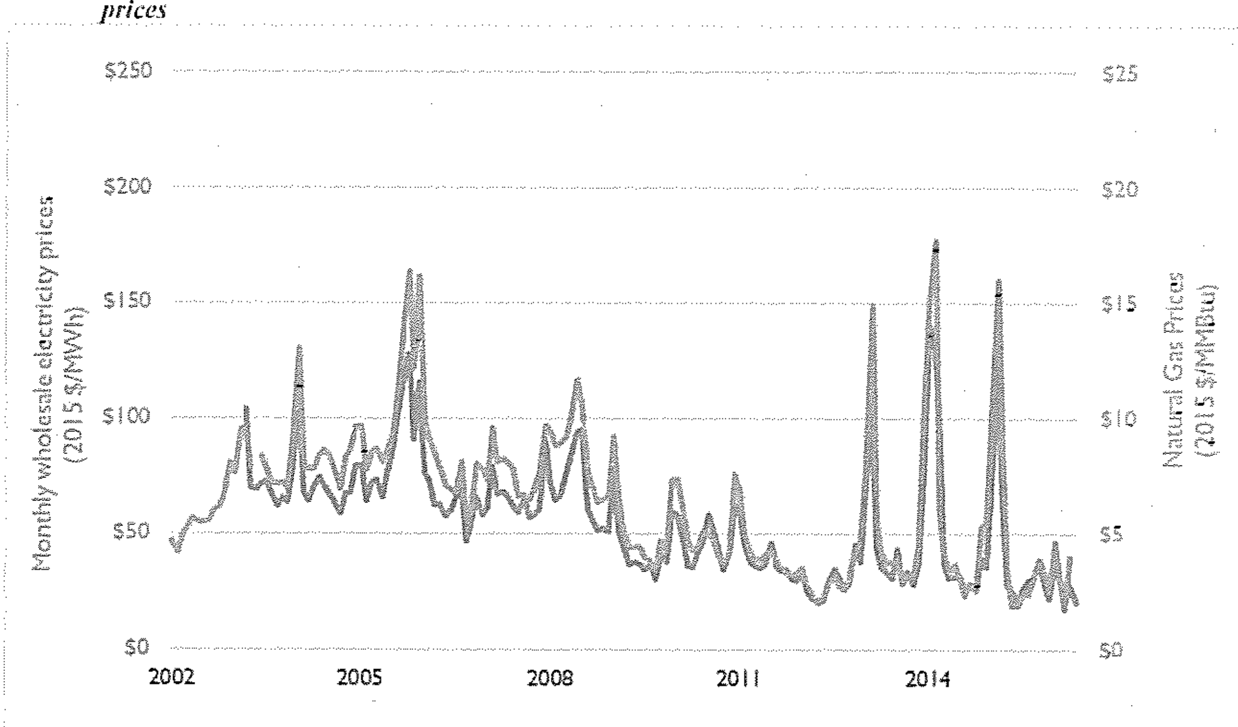
assets/documents/markets/hstdata/znl_info/monthly/smd_monthly.xls submitted as Exhibit CLF-EAS-3, sheet "LMP_Monthly")

Notes: Actual wholesale electricity prices based on locational marginal prices (LMPs) at the ISO-NE hub. LMPs used from Black & Veatch's modeling are for Western Massachusetts (WMA). For all actual data, peaks in each yearly period from April through March were compared to the average natural gas price over the same period. This same methodology is applied to the Black & Veatch data.

Q. What determines wholesale electric prices?

A. In New England, generation powered by natural gas is "on the margin" in a large share of hours throughout the year; that is, in a given hour, a natural gas combined cycle is the last resource to be dispatched based on variable price and, therefore, sets the wholesale market price of electricity. For this reason, as depicted in Figure 9, there is a very close relationship between the price of natural gas delivered to electric power consumers (shown in green) and the wholesale price of electricity (shown in blue).

Figure 9. Relationship between historical monthly wholesale electricity prices and wholesale natural gas prices



Sources: ISO-NE monthly LMP data (available at http://www.iso-ne.com/static-

assets/documents/markets/hstdata/znl_info/monthly/smd_monthly.xls submitted as Exhibit CLF-EAS-3, sheet "LMP_Monthly"); monthly EIA natural gas prices (http://tonto.eia.gov/dnav/ng/hist/n3045ma3m.htm submitted as Exhibit CLF-EAS-3, sheet "LMP_Monthly").

Notes: Actual wholesale electricity prices based on locational marginal prices (LMPs) at the ISO-NE hub. Actual natural gas prices based on the price of natural gas delivered to electric power customers in Massachusetts.

Q. How does the monthly average price of natural gas delivered to electric generators in the modeling results submitted by the petitioner relate to historical prices in New England?

A. As depicted in Figure 10 and Figure 11, with the exception of three winters (2012/2013, 2013/2014, and 2014/2015) the highest monthly wholesale natural gas price has been 15 to 64 percent higher than the average price in each year (April to March) since 2003 (see Exhibit CLF-EAS-3, sheet "NGPrices_Monthly").

As with wholesale electricity prices, in years 2012/2013, 2013/2014, and 2014/2015 wholesale natural gas prices spiked at levels that were anomalously higher than in years before or since: the highest monthly natural gas price was 169 to 220 percent higher than those years' average prices. In 2015/2016, the highest monthly natural gas price was just 64 percent higher than that year's average price.

In comparison, as shown in Figure 11 Black & Veatch's No Pipeline case, on average across the modeled years, the highest monthly wholesale natural gas price is [redacted] percent higher than the average price in each year (where the yearly average is based on the year of data modeled). In comparison, in historical years other than 2012-2015, the highest monthly wholesale electric price is just 41 percent higher than the average price. The unexplained increase in prices in the No Pipeline case appears to largely drive the petitioner's modeled benefits of implementing a pipeline.

Figure 10. Monthly natural gas prices: historical and Black & Veatch scenarios

Sources: Attachment NEER 1-3(a); monthly EIA natural gas prices (http://tonto.eia.gov/dnav/ng/hist/n3045ma3m.htm and https://www.eia.gov/electricity/wholesale/#history submitted as Exhibit CLF-EAS-3, sheet "NGPrices_Monthly")

Notes: Actual natural gas prices based on the price of natural gas delivered to electric power customers in Massachusetts through February 2014 and natural gas delivered to Algonquin Citygate in March 2014 and after. Natural gas prices used from Black & Veatch's modeling are for deliveries to Algonquin Citygate.

Figure 11. Peak monthly natural gas price as a percentage of annual average: historical and Black & Veatch scenarios

Sources: Attachment NEER-1-3(a); monthly EIA natural gas prices (http://tonto.eia.gov/dnav/ng/hist/n3045ma3m.htm and https://www.eia.gov/electricity/wholesale/#history submitted as Exhibit CLF-EAS-3, sheet "NGPrices_Monthly")

Notes: Actual natural gas prices based on the price of natural gas delivered to electric power customers in Massachusetts through February 2014 and natural gas delivered to Algonquin Citygate in March 2014 and after. Natural gas prices used from Black & Veatch's modeling are for deliveries to Algonquin Citygate. For all actual data, peaks in each yearly period from April through March were compared to the average natural gas price over the same period. This same methodology is applied to the Black & Veatch data over both series.

Q. How do annual average natural gas prices delivered to electric generators in the modeling results submitted by the petitioner relate to historical prices in New England?

A. The annual natural gas prices used in the Black & Veatch modeling (Attachment NEER-1-3(a)) are far higher than the most recent Energy Information Administration forecasts and NYMEX Futures. As shown in Figure 12, Black &

Veatch uses different forecasted natural gas prices in its No Pipeline and With ANE Only cases. In 2018, the annual price of natural gas (delivered to Algonquin Citygate) ranges from [redacted] (in 2015 dollars) per million British thermal units (MMBtu) in the two cases. In the No Pipeline scenario, these prices rise to [redacted] per MMBtu in 2038 (an increase of [redacted] percent above 2015 actuals), while in the With ANE Only scenario, these prices rise to [redacted] per MMBtu (an increase of [redacted] percent above 2015 actuals). Black & Veatch's modeling runs begin in 2018; natural gas prices for 2016 and 2017 were not modeled. Black & Veatch did model 2039 and 2040 but the petitioner did not report gas prices for these years and has not responded to CLF's request for an explanation of the missing data.

Figure 12 also shows two projections of natural gas prices delivered to New England electric generators published in the EIA 2016 Annual Energy Outlook (AEO). Both the AEO 2016 Reference Case and the AEO 2016 No CPP Case start at a price of $3.97 per MMBtu in 2015. This price is $0.41 per MMBtu less expensive than 2015 actual prices, and equivalent to Black & Veatch's modeled price for 2018. By 2038, these the AEO 2016 prices rise to $5.74 per MMBtu in the Reference Case (an increase of 31 percent above 2015 actuals) and $5.46 in the No CPP Case (an increase of 25 percent compared to 2015 actuals).

Finally, Figure 12 also shows the NYMEX Futures price for natural gas in 2016 and 2017 (adjusted to reflect the basis differential between Henry Hub and New England electric power generators; see Exhibit CLF-EAS-3, sheet "NGPrices_Annual"). These prices are $3.25 per MMBtu and $3.79 per MMBtu, respectively—lower still than either Black & Veatch or EIA's projections.

Figure 12. Annual natural gas price comparison

Sources: Attachment NEER 1-3(a); monthly EIA natural gas prices (http://tonto.eia.gov/dnav/ng/hist/n3045ma3m.htm submitted as Exhibit CLF-EAS-3, sheet "NGPrices_Annual"); Annual Energy Outlook (AEO) 2016 natural gas prices for Reference Case and No CPP Case (http://www.eia.gov/forecasts/aeo/ submitted as Exhibit CLF-EAS-3, sheet "NGPrices_Annual"); NYMEX Futures (https://www.eia.gov/forecasts/steo/report/natgas.cfm submitted as Exhibit CLF-EAS-3, sheet "NGPrices_Annual")

Notes: Actual natural gas prices based on the price of natural gas delivered to electric power customers in Massachusetts. AEO 2016 natural gas prices are based on the price of natural gas delivered to electric power customers in New England. Natural gas prices used from Black & Veatch's modeling are for natural gas deliveries to Algonquin Citygate. NYMEX Futures for natural gas delivered to the New England electric sector are calculated by increasing the Henry Hub NYMEX Futures by the basis differential percentage between Henry Hub and delivered natural gas to the Massachusetts electric sector based on the AEO 2016 Reference Case.

Q. Do the modeled cases with and without the pipeline submitted by the petitioner appropriately model future wholesale electric prices?

A. No. While Black & Veatch correctly models the relationship between natural gas prices and wholesale electricity prices, its peak monthly natural gas price projections in the No Pipeline case are higher in relation to average monthly prices than has been the case in recent historic years. Specifically, the ratio of peak monthly natural gas price to monthly average price in the No Pipeline case is higher than that same ratio in historical years other than 2012 through 2015—suggesting that the petitioner expects conditions in those years to continue into the future.

In addition, Black & Veatch's annual natural gas price projections in the No Pipeline case exceed:

- recent actual prices,
- near-term price projections from the commodities markets, and
- EIA's forecasts for the long-term.

The over-estimation of natural gas price in the No Pipeline case exaggerates the potential economic benefits of the ANE pipeline project.

Q. Has the petitioner submitted modeling results useful to a determination of whether or not a new natural gas pipeline is necessary for or beneficial to Massachusetts?

A. No. The modeling results submitted by the petitioner use artificially high seasonal and annual natural gas prices in the No Pipeline case, exaggerating the likely economic benefits associated with the ANE pipeline. A credible set of seasonal and annual natural gas price assumptions would lower the likely economic benefits associated with the ANE pipeline.

4. KEY ALTERNATIVE RESOURCES TO NATURAL GAS ARE OMITTED FROM THE PETITIONER'S MODELING RESULTS.

Q. What is the Massachusetts' Renewable Portfolio Standard?

A. The Massachusetts Renewable Portfolio Standard (RPS) requires investor-owned electric suppliers to obtain a set percentage of their electricity from qualifying renewable resources. The Massachusetts RPS was established by the Massachusetts Electric Utility Restructuring Act of 1997, and was amended by the Massachusetts Green Community Act of 2008.

Q. What are the current requirements of the RPS?

A. Currently, the Massachusetts RPS is divided into "Class I" and "Class II" requirements. Class I requirements may only be fulfilled through the purchase of electricity from renewable generation facilities that began operation after 1997. For 2016, the Class I RPS requirement is 11 percent of all electric sales by investor-owned suppliers. This requirement increases by one percentage point each year, such that it will reach 15 percent in 2020 and 35 percent in 2040. Class II RPS requirements may only be met through the purchase of electricity from renewable generation facilities that began operation before 1998. The Class II renewable generation requirement is currently 3.6 percent, and is not slated to increase in future years.

Q. What technologies are eligible for meeting the RPS Class I requirements?

A. Eligible technologies include solar photovoltaic, solar thermal, wind, small hydropower, landfill methane, anaerobic digester gas, marine, hydrokinetic, geothermal, and certain biomass generation resources.

Q. Do the modeling results submitted by the petitioner comply with Massachusetts RPS requirements?

A. To the best of my knowledge, no. Information Request CLF-1-6 asked the petitioner:

For Massachusetts, by how much is the share of total state electric demand for which REC purchases required grow in ever year after 2020?

The petitioner's response implies that Black & Veatch intended to model the Massachusetts RPS to continue increasing after 2020:

Beyond 2020, the share of total MA electric demand to be served by REC purchases grows by 1% each year.

However, examination of Black & Veatch's modeling outputs in Attachment NEER 1-1(b) suggests otherwise: first, Black & Veatch withheld renewable generation data for the With ANE Only case (despite CLF asking for clarifying information pursuant to Attachment NEER-1-1(b)); instead, wind and solar generation data was provided in Attachment 1-1(b) for the "Base Case" or No Pipeline case only. Solar and wind generation was not provided for any of the other scenarios, including the "With NED Only" scenario, or the "With ANE and NED" scenario. Second, analysis of this data shows that Black & Veatch's modeling—using the assumption that Black & Veatch's renewable build out is the same in both the No Pipeline and With ANE Only cases—did not produce sufficient wind to meet the Massachusetts RPS requirements in all years.

Electric sales decrease over time in the New England region in Black & Veatch's analysis ([redacted] percent annually) and—among New England states—only the Massachusetts RPS continues to grow after 2025 (other than Vermont's renewables requirement which can be met through Canadian imports). Any increase in the demand for renewables for RPS compliance in New England after 2025, therefore, must necessarily come from the continued growth in Massachusetts RPS: I calculate this growth to be [redacted] terawatt-hours (TWh) in Class I renewables from 2025 to 2040. My analysis of Attachment NEER-1-1(b) shows that Black & Veatch's scenarios have increases in New England wind generation of only [redacted] TWh over this period while other renewable generation (only some of which is likely to be RPS eligible) including in-region hydro, biomass, and "other" decreases by [redacted] TWh (see Exhibit CLF-EAS-3, sheet "RPS_Analysis"). This is an increase of at most [redacted] TWh, well short of the [redacted] TWh required from the Massachusetts RPS increase. It seems very unlikely that Black & Veatch is correctly modeling Massachusetts RPS.

Q. Should the level of renewables projected under the Massachusetts RPS be expected to interfere with ISO-NE's ability to reliably operate the New England electric grid?

A. No. Even if the incremental generation to meet the correct Massachusetts RPS was met exclusively through wind there is no evidence to suggest that ISO-NE would not be capable of integrating that level of renewables. A 2012 report from ISO-NE stated that, "Large scale wind integration, i.e. up to 12,000 MW, is feasible for operating in New England's electric grid." (see Exhibit CLF-EAS-6). Using an average peak level of demand for ISO-NE of 20,000 MW, this is equivalent to operating a grid consisting of 60 percent of wind generation. Other system operators around the country regularly achieve high system-wide levels of wind generation. For example, on March 23, 2016, ERCOT (the system operator for much of Texas) successfully operated a grid consisting of 48 percent wind (see Exhibit CLF-EAS-7). In addition, other system operators are exploring changes to operation procedures that would accommodate levels of as high as 60 percent wind (see Exhibit CLF-EAS-9).

Q. What would be the likely impact on the petitioner's modeling results of correctly representing the Massachusetts RPS?

A. If Black & Veatch has underestimated the amount of renewable generation necessary to fulfill Massachusetts RPS, a correction to this error would lower demand for natural gas in the region.

Using the simplified assumption that all new, incremental generation built to meet the correct Massachusetts RPS displaces generation from natural gas generators, [redacted] TWh of natural gas generation would be displaced in 2040 in the Black & Veatch No Pipeline scenario and [redacted] TWh of natural gas generation would be displaced in 2040 in the Black & Veatch With ANE Only scenario. This is calculated by comparing the incremental demand for renewables from the Massachusetts RPS in 2040 over that of 2025 ([redacted] TWh) against the region-wide increase in renewables in 2040 over 2025 levels ([redacted] TWh). Even if the [redacted] TWh Black & Veatch models in 2040 as incremental to 2025 were allotted to the Massachusetts RPS, [redacted] to [redacted] TWh of renewables would still be required to be in compliance. By 2040, [redacted] percent of all incremental natural gas generation since 2016 modeled in the two Black & Veatch scenarios would be displaced by the additional wind or solar needed to meet the RPS (see Exhibit CLF-EAS-3, sheets "RPS_Analysis" and "Displacement Analysis").

Q. What Massachusetts laws require the use of energy efficiency resources to meet electricity demand?

A. The Massachusetts Green Communities Act of 2008 requires that all available, cost-effective energy efficiency resources be used to meet electricity demand. The same law requires that, every three years, Massachusetts electric distributors prepare a joint energy efficiency plan that provides for "the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." (Ch.25, Section 21(b)(1))

Q. What are Massachusetts' current energy efficiency targets?

A. The most recent three-year plan submitted by the Massachusetts energy efficiency program administrators contains an annual energy efficiency savings goal of 2.93 percent of retail sales over the period from 2016 to 2018 (Massachusetts Gas and Electric Pas Energy Efficiency Plan 2016-2018 submitted as Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis").

Q. What estimates does the petitioner use to forecast electric demand in its modeling results?

A. The Black & Veatch analysis (NG-JNC-3) uses ISO New England CELT 2015 net of energy efficiency and distributed PV generation (response to Information Request CLF-1-1(e)).

Q. Does the ISO New England CELT 2015 net of energy efficiency and distributed PV generation omit any known sources of demand reductions?

A. Yes. While ISO's CELT forecast is developed each year with input from stakeholders in the Energy Efficiency Forecast Working Group, it is known to include several deficiencies that inaccurately represent demand reductions in future years. According to a report released in July 2015 by Paul Peterson and Spencer Fields of Synapse Energy Economics (Exhibit CLF-EAS-8) these deficiencies include:

- Budget uncertainty: In CELT 2015 Energy Efficiency Forecast, ISO-NE applied a 10 percent reduction to the annual energy efficiency budgets of

Maine, Massachusetts, and Rhode Island. This reduction was applied because these three states did not expend their full budgets in 2014. ISO assumes this underspending will not only continue in future years but that it will be associated with a failure to meet savings goals. This budget reduction effectively reduces the amount of savings predicted from these states' energy efficiency programs.

- Production cost escalation: ISO-NE assumes that the future cost of implementing energy efficiency on a per-MWh basis increases by 5 percent per year. Neither data from New England nor other national data on energy efficiency costs support such an assumption. This increase in the unit cost of energy efficiency savings means fewer savings are achieved for the same program budget.
- Inflation adjustments: ISO-NE applies an inflation adjustment of 2.5 percent to the cost of energy efficiency savings. No corresponding inflation adjustment is applied to energy efficiency program budgets, resulting in an overall decrease in the amount of energy efficiency savings possible.
- Forecasted versus cleared savings: Over time, the ISO's forecast for energy efficiency savings in future years has been consistently below the total energy efficiency savings cleared in Forward Capacity Auctions. In addition, the energy efficiency resources that clear in the auction are a subset of a larger quantity of resources that are qualified to participate in the auction. Energy efficiency program administrators often clear slightly lower amounts than is qualified as a way to protect against under-achievement of future installation rates. Furthermore, cleared quantities can be de-rated to reflect decisions to pro-rate the quantity of cleared megawatts region-wide.
- Distributed PV discounting: In its planning process, ISO-NE applies two

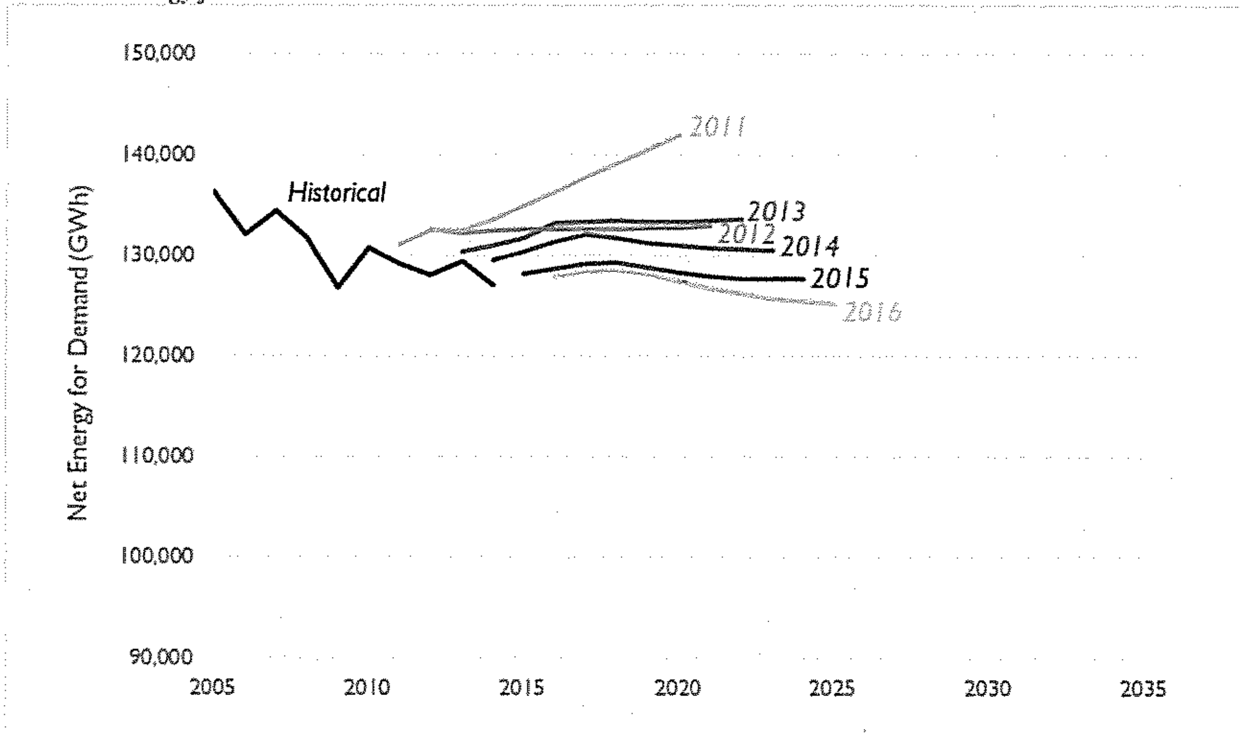
> different discount factors to expected levels of distributed PV generation projected by the five New England states with resource-specific mandates or goals. For years with explicit state mandates or goals, distributed PV generation can be discounted by up to 50 percent. For years after a mandate or goal, distributed PV generation can be discounted by up to 75 percent. This methodology leads to a forecast that shows diminishing distributed PV generation in future years.

Accounting for the deficiencies identified in the Peterson/Fields report would change the annual growth rate for net energy for load in the CELT 2015 forecast from -0.04 percent per year to -1.43 percent per year (see Exhibit CLF-EAS-8, page 15).

Q. How have the ISO New England CELT 2015 net of energy efficiency and distributed PV generation changed over time?

A. Each year, ISO-NE releases an update to its CELT forecast. This forecast includes a projection of future energy for demand, net energy efficiency, and distributed PV generation. With the exception of 2013, for each of the past five new releases of the CELT forecast, the ISO-NE has revised downward its projections of net energy for demand (see Figure 13). In its most recent forecast, the CELT 2016 Draft Forecast, ISO-NE expects the annual growth rate for the next ten years to change from -0.04 percent per year in the 2015 CELT forecast to -0.25 percent per year (see Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis").

Figure 13. ISO-NE Forecasts of net energy for demand from 2011 through 2016 (draft) compared to actual net energy for demand



Sources: ISO CELT 2011-2015 (http://www.iso-ne.com/system-planning/system-plans-studies/celt submitted as Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis")); ISO CELT 2016 submitted as Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis").

Q. What do the six New England states' planned energy efficiency reductions suggest about future New England electric demand?

A. Each of the six New England states have goals, mandates, or targets for energy efficiency. Depending on the state, these forecasts have been released for between one and ten future years. In 2016, these annual incremental savings range from 0.43 to 2.20 percent of 2016 sales (see Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis"). If these savings were continued into the future, I estimate that the cumulative average annual growth rate over 2015 to 2040 would be -0.26 percent per year (see Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis").

Q. What would be the likely impact on the petitioner's modeling results representing expected future electric demand as the continuation of current energy efficiency requirements?

A. A correction to this error would lower demand for natural gas in the region. Figure 14 compares the ISO's projections for net energy for demand against: (1) New England planned savings (an average growth rate of -0.26 percent per year), and (2) electric demand after adjusting for known deficiencies in the ISO's energy efficiency forecast presented in the Peterson/Fields report (an average growth rate of -1.43 percent per year). Replacing Black & Veatch's projection for net energy for demand (i.e., the CELT 2015 forecast, with an average growth rate of -0.04 percent per year) with the CELT 2016 projection for net energy for demand (an average growth rate of -0.25 percent per year) would yield a [redacted] TWh decrease in retail sales in 2040 (see Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis" and "Displacement_Analysis").

Using the simplified assumption that this decrease in retail sales displaces generation from natural gas generators, using the CELT 2016 projection for net energy for demand, [redacted] TWh of natural gas generation would be displaced in 2040 in both the Black & Veatch scenario No Pipeline and With ANE Only scenarios after accounting for transmission and distribution losses. By 2040, [redacted] percent of all incremental natural gas generation since 2016 modeled in the two Black & Veatch scenarios would be displaced by the CELT 2016 decrease in demand.

Figure 14. ISO-NE Forecasts of net energy for demand from 2011 through 2016 (draft) compared to actual net energy for demand, demand after accounting for New England Planned savings, and demand after adjusting for known deficiencies in the ISO's energy efficiency forecast

Sources: Exhibit NG-JNC-3, page 6; ISO CELT 2011-2015 (http://www.iso-ne.com/system-planning/system-plans-studies/celt); ISO CELT 2016 submitted as Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis"; New England planned energy efficiency savings (http://www.synapse-energy.com/sites/default/files/RGGI_Opportunity_2.0.pdf submitted as Exhibit CLF-EAS-3, sheet "ISO_CELT_Analysis"; Peterson/Fields adjustments (Exhibit CLF-EAS-8).

Q. Has the Baker Administration taken a position on the need for increased renewable energy imports?

A. Yes. In 2015, Governor Baker submitted to the Massachusetts Senate and House of Representatives proposed legislation entitled "An Act Relative to energy sector compliance with the Global Warming Solutions Act." (S.1965). This bill would require Massachusetts electric distribution companies to solicit 18.9 TWh of hydroelectricity imports, or hydroelectricity imports blended with RPS Class I-eligible renewable generation. Governor Baker has stated that these imports are necessary to ensure that Massachusetts meets the goals of its GWSA. The 2015 Update to the CECP (Exhibit CLF-EAS-4) calls for 4 MMT of reductions from new hydroelectricity imports, roughly equal to 9.9 TWh, assuming generation from natural gas combined cycle generators is displaced by new imports (see Exhibit CLF-EAS-3, sheet "Imports Analysis").

Q. Has the legislature moved to pass this bill?

A. The Massachusetts House of Representatives passed a similar bill (H.4385) on June 8, 2016. It would require Massachusetts electric distribution companies to solicit up to 9.45 TWh of hydroelectricity imports or hydroelectricity imports blended with RPS Class I-eligible renewable generation. It would also require Massachusetts electric distribution companies to solicit at least 1,200 MW installed capacity of offshore wind generation by 2027.

Q. Do the modeling results submitted by the petitioner include the increase in hydroelectricity imports needed to meet the goals of the GWSA?

A. No. Black & Veatch's scenarios do not appear to include any incremental imports from hydroelectricity. Figure 15 shows the implied imports to New England from Black & Veatch's modeling (calculated by subtracting in-region generation provided in Attachment NEER 1-1(b) and attachment NEER 1-1(c) from in-region sales provided in Attachment NEER 1-1(f), adjusted for transmission and distribution losses; see Exhibit CLF-EAS-3, sheet "Imports_Analysis"). Black & Veatch calculates annual net electricity imports to be almost identical between the No Pipeline scenario and the With ANE Only scenario: In 2040, calculated imports are estimated to be [redacted] percent lower in both the No Pipeline and With ANE Only scenarios than 2015 historical imports. For both scenarios, in all years after 2018, calculated net imports are estimated to remain below the level of imports observed in 2015, and are [redacted] to [redacted] percent of the total level of imports that would result from the June 2016 House energy bill (H.4385).

Figure 15. Net imports to New England, 2000 through 2040

Sources: Attachment NEER-1-1(b); Attachment NEER-1-1(c); Attachment NEER-1-1(f); EIA historical generation data (http://www.eia.gov/electricity/data/state/annual_generation_state.xls and http://www.eia.gov/electricity/data/eia923/ submitted as Exhibit CLF-EAS-3, sheet "Imports_Analysis"); EIA historical retail sales (http://www.eia.gov/electricity/data/state/sales_annual.xls and https://www.eia.gov/electricity/data/eia826/ submitted as Exhibit CLF-EAS-3, sheet "Imports_Analysis"); and H.4385.

Notes: Imports to New England calculated by subtracting the total generation from New England generators from the total net energy for demand for consumers in New England states. Data points modeled by Black & Veatch in both No Pipeline and With ANE Only cases; "With Clean Energy Imports" assumes the level of hydroelectricity required in the June 2016 House energy bill H.4385 (9.45 TWh) is added to the level of net imports of electricity to New England in 2015.

Q. Are the electric imports modeling results submitted by the petitioner consistent with the petitioner's sales less generation?

A. No. The level of net imports of electricity specified as being modeled by the petitioner in Attachment NEER 1-1(e) are [redacted] to [redacted] percent of the level of net electricity imports calculated by subtracting New England electric generation from New England sales, adjusted for transmission and distribution losses. This difference does not appear to be explained in the petitioner's testimony or exhibits. Figure 16 compares the methodology used for calculating sales less generation labeled as net electricity imports in Figure 15 with the net electricity imports reported in Attachment NEER 1-1(e).

Figure 16. Net imports to New England, 2000 through 2040; comparison of methods

Notes: Solid lines indicate net electricity imports calculated by subtracting New England electric generation from New England sales, adjusted for transmission and distribution losses. Dashed lines indicate net electricity imports as reported in Attachment NEER-1-1(f).

Sources: Attachment NEER-1-1(b); Attachment NEER-1-1(c); Attachment NEER-1-1(e); Attachment NEER-1-1(f); EIA historical generation data (http://www.eia.gov/electricity/data/state/annual_generation_state.xls and http://www.eia.gov/electricity/data/eia923/ submitted as Exhibit CLF-EAS-3, sheet "Imports_Analysis"); EIA historical retail sales *(http://www.eia.gov/electricity/data/state/sales_annual.xls and https://www.eia.gov/electricity/data/eia826/ submitted as Exhibit CLF-EAS-3, sheet "Imports_Analysis"); and H.4385.*

Q. What would be the likely impact on the petitioner's modeling results of correctly representing the new hydroelectric imports needed to meet GWSA goals?

A. A correction to this error would lower demand for natural gas in the region.

Using the simplified assumption that incremental imports to 2015 levels displace generation from natural gas generators, representing the new hydroelectric imports needed to meet GWSA goals would result in [redacted] TWh of natural gas generation displaced in 2040 in both the Black & Veatch scenario No Pipeline and With ANE Only cases. By 2040, [redacted] percent of all incremental natural gas generation since 2015 modeled in the two Black & Veatch scenarios would be displaced by the additional imported electricity called for in H.4385 (see Exhibit CLF-EAS-3, sheet "Imports_Analysis: and "Displacement_Analysis").

Q. Does Massachusetts comply with state renewables, efficiency, and greenhouse gas emission regulations in the modeled cases of future generation with and without the ANE pipeline submitted by the Petitioner?

A. No. In Black & Veatch's No Pipeline and With ANE Only cases:

- Massachusetts does not appear to comply with its RPS.
- New England states—including Massachusetts—do not appear to achieve the level of energy efficiency modeled by ISO-NE in its 2016 draft CELT electric demand forecast.
- New England's electric imports are not consistent with the level of new hydroelectric imports called for by the Massachusetts House of Representatives as necessary to comply with the GWSA.

Q. Has the petitioner submitted modeling results useful to a determination of whether or not a new natural gas pipeline is necessary for or beneficial to Massachusetts?

A. No. The modeling results submitted by the petitioner do not appear to be consistent with a future in which state laws are followed.

5. THE PETITIONER'S MODELING RESULTS DO NOT ACCURATELY PORTRAY EXPECTED FUTURE CONDITIONS IN MASSACHUSETTS.

Q. Do the modeling results submitted by the petitioner accurately represent likely future conditions in the New England electric sector?

A. No.

Q. What basic assumptions would you expect to see in this type of modeling exercise in the baseline case?

A. I would expect the baseline or business-as-usual case (here, Black & Veatch's No Pipeline) to include assumptions necessary to represent all current laws and regulations and either the most likely projection of uncertain future values (fuel prices, electric demand, etc.) or an exploration of the sensitivity of modeling results to changes in projections of these key uncertain variables.

Q. Do the modeling results submitted by the petitioner meet these basic expectations related to the baseline case?

A. No. Black & Veatch's No Pipeline does not appear to comply with RGGI, GWSA, the Clean Power Plan, Massachusetts RPS, and New England states' energy efficiency obligations. In addition, natural gas prices used in Black & Veatch's modeling neither appear to the most likely projections of uncertain future values nor do they explore the sensitivity of modeling results to changes in projections of the price of natural gas.

Q. What basic assumptions would you expect to see in this type of modeling exercise in the case representing a change in policy or project?

A. I would expect the case representing a change in policy or project (here, Black & Veatch's With ANE Only case) to differ from the baseline case (No Pipeline) only in those assumptions related to the introduction of the policy or project. In all other respects, I would expect inputs into the model to be identical in both cases.

Q. Do the modeling results submitted by the petitioner meet these basic expectations related to the case representing a change in policy or project?

A. Yes. This means, however, that deficiencies in the No Pipeline case are also present in the With ANE Only case. Therefore, Black & Veatch's With ANE Only case does not appear to comply with RGGI, GWSA, the Clean Power Plan, Massachusetts RPS, and New England states' energy efficiency obligations. In addition, natural gas prices used in Black & Veatch's With ANE Only case neither appear to the most likely projections of uncertain future values nor do they explore the sensitivity of modeling results to changes in projections of the price of natural gas.

Q. Do the modeling results submitted by the petitioner include assumptions necessary to represent all current laws and regulations?

A. No. The petitioner's modeling results do not appear to include assumptions necessary to represent all current laws and regulations:

- Massachusetts relies on unexplained emission reductions in the other RGGI states to achieve its own compliance with RGGI.
- Massachusetts' electric sector emissions are in line with the expectations in the 2015 Update to the CECP for 2020 (Exhibit CLF-EAS-4), but subsequently increase and are higher than this 2020 target in years 2022 through 2040.
- Massachusetts' generators regulated under the Clean Power Plan emit more CO_2 than allowed for under the state's cap—<u>again, requiring its excess emissions to be balanced by extra emission reductions in other states to achieve compliance.</u>
- Massachusetts does not appear to comply with its RPS.
- New England states—including Massachusetts—do not appear to achieve the level of energy efficiency modeled by ISO-NE in its 2016 draft CELT electric demand forecast.
- New England's electric imports are not consistent with the level of new

hydroelectric imports called for by Governor Baker and the Massachusetts House of Representatives as necessary to comply with the GWSA.

Q. Do the modeling results submitted by the petitioner include the most likely projection of uncertain future values (fuel prices, electric demand, etc.) or an exploration of the sensitivity of modeling results to changes in projections of these key uncertain variables?

A. No. The modeling results submitted by the petitioner appear to use artificially high seasonal and annual natural gas prices, exaggerating the likely net benefits associated with the ANE.

Q. What would be the likely impact on the petitioner's modeling results from the combination of correctly modeling the Massachusetts RPS, the CELT 2016 forecast, and the new hydroelectric imports needed to meet GWSA goals?

A. Correctly modeling Massachusetts RPS, the CELT 2016 forecast, and the new hydroelectric imports needed to meet GWSA goals would require:

- increasing wind generation by [redacted] to [redacted] TWh in 2040 to be consistent with Massachusetts' RPS,
- lowering sales by [redacted] TWh ([redacted] TWh after accounting for transmission and distribution losses) in 2040 to be consistent with the CELT 2016 forecast, and
- raising the level of imports to New England by [redacted] TWh in 2040 to be consistent with H.4385.

As illustrated in Figure 17, a simplified approach to representing the impact of these changes on Black & Veatch's modeling results in natural gas generation that is [redacted] TWh lower in the No Pipeline and With ANE Only cases in 2040 (a reduction of [redacted] to [redacted] percent below Black & Veatch's modeled 2040 levels of natural gas generation and [redacted] percent below actual 2015 natural gas generation) (see Exhibit CLF-EAS-3, sheet "Displacement_Analysis").

Figure 17. Generation and sales in 2016 and 2040: Black & Veatch scenarios and simplified modifications

Sources: Exhibit CLF-EAS-3, sheet "Displacement_Analysis".

Note: Values may not sum due to rounding.

Q. What would be the likely impact on greenhouse gas emissions of decreasing natural gas generation by [redacted] TWh in 2040?

A. Decreasing New England's 2040 natural gas generation by [redacted] TWh (and replacing this generation with renewables, efficiency, and hydroelectric imports) would lower regional emissions by [redacted] million short tons of CO_2.

Q. What would be the likely impact on RGGI, GWSA, and Clean Power Plan compliance of decreasing natural gas generation by [redacted] TWh in 2040?

A. Decreasing New England's 2040 natural gas generation by [redacted] TWh (and replacing this generation with renewables, efficiency, and hydroelectric imports) and thereby lowering regional emissions by [redacted] million short tons of CO_2 would greatly improve Massachusetts chances of complying with RGGI, GWSA, and the Clean Power Plan, and doing so without relying on emission reductions in other states (see Exhibit CLF-EAS-3, sheet "Displacement_Analysis"). In 2040, Massachusetts's emissions in the Black & Veatch modeled cases are [redacted] to [redacted] million short tons above the Commonwealth's share of RGGI allowances, [redacted] to [redacted] million short tons above the electric-sector's implied emission target for the Massachusetts GWSA (based on its past responsibility for reductions), and [redacted] to [redacted] million short tons above its Clean Power Plan target.

Q. What would be the likely impact on winter natural gas price spikes of decreasing natural gas generation by [redacted] TWh in 2040?

A. A reduction of [redacted] to [redacted] percent in New England's natural gas generation would reduce total demand for natural gas on peak winter days and could therefore be expected to reduce or remove winter price spikes in natural gas and, consequently, winter spikes in wholesale electric prices.

Q. What would be the likely impact on the economics benefits of the ANE of decreasing natural gas generation by [redacted] TWh in 2040?

A. The economic benefits forecasted by the petitioner from the construction and operation of the ANE are the result of difference in the winter wholesale electric prices between the No Pipeline and With ANE Only cases. Without a difference in winter electric prices there would be no economic benefit from the ANE project.

Q. Does this conclude your testimony?

A. Yes, it does.