PUC 3-1

Request:

Referencing National Grid's Response to **PUC 2-43**, please provide the rationale for conducting the Proposal Case assuming all three projects (1400 MW) being built. Why did the Proposal Case not assume that the Rev I, LLC project would be in addition to only the Vineyard Wind project being constructed (800 MW), or based on an assumption that the Rev I, LLC project would be in addition to only the CT Revolution wind project being constructed (200 MW)? In other words, the question was trying to ask why the study was comparing an all-constructed versus none-constructed analysis.

Response:

The Company's analysis assumed that all of the offshore wind procured by Massachusetts, Connecticut, and Rhode Island would be constructed because all of the projects were selected at around the same time. Specifically, Massachusetts and Rhode Island made the project selection as part of the same solicitation, and Connecticut made its project selection, which is an expansion of the Rhode Island project, shortly thereafter. Rhode Island's selection of the 400 MW Revolution Wind project enabled the selection of the 200 MW Connecticut project that would likely not otherwise proceed. The projects are all at the same stage of development (selected but construction not started). Also, the states have similar goals for conducting these procurements. The Company has no information that any of the offshore wind projects is more likely to be constructed than the others, and the Company sought to accurately quantify the benefits of a regional procurement of offshore wind.

PUC 3-2

Request:

Referencing National Grid's response to PUC 2-12b:

a. Are energy imports and the related environmental attributes of these imports tracked with NEPOOL GIS Certificates? Please reference NEPOOL GIS Operating Rules Rule 2.7 in the response.

b. Please indicate if National Grid's response to PUC 2-12b is indicating that attribute-tracking Certificates are not created for energy imports.

c. Please indicate if the environmental attributes of non-renewable imported energy and imported renewable energy that is not retired against load by the annual NEPOOL GIS trading deadline are included in Residual Mix through NEPOOL GIS Certificates.

d. Please indicate if National Grid's response to PUC 2-12b means that National Grid's Energy Source Disclosure filings use information other than NEPOOL GIS certificates to present the environmental attributes of imported energy that is otherwise already included in Residual mix.

e. Please indicate if National Grid's response to PUC 2-12b is describing a process for accounting for imported energy that is different from the process that National Grid uses to calculate coal, nuclear, oil, natural gas, or any other fuel type that contributes to Residual Mix. If so, please explain why. If not, please provide more detail on why National Grid's response to PUC 2-12b is "disagree."

f. Please indicate if National Grid uses the Executive Climate Change Coordinating Council (EC4) methodology from the Rhode Island Greenhouse Gas Emission Reduction Plan (EC4 Plan Report) to create Energy Source Disclosure filings.

g. Please indicate if the EC4 Plan Report or any part of it was adopted as rule or regulation.

h. Please explain if National Grid believes it would improve or damage confidence in the regional REC market and Rhode Island-eligible resources if the State of Rhode Island did the following: accept obligated entities' annual RES filings that their load served was X% renewable as substantiated by the retirement of RECs while also declaring that Rhode Island's energy consumption was Y% renewable as substantiated by the EC4 Plan Report methodology National Grid has used in this filing. Why or why not?

i. Please explain if analogous, consumption-based greenhouse gas inventories in other New England states use the EC4 Report Plan methodology to establish consumption-based emissions or if these states use NEPOOL GIS and Certificate-based methodologies.

j. If National Grid believes consumption-based emissions can be established using the EC4 Plan Report methodology, please respond to the following:

    i. Why does National Grid purchase RECs on behalf of its customers?

    ii. Why does National Grid use NEPOOL GIS Certificates to establish its Energy Source Disclosure? and

    iii. Why does National Grid believe other market actors will purchase RECs from Revolution I?

Response:

Please refer to the Company's supplemental response to Data Request PUC 2-12. The Company agrees that only NEPOOL GIS certificates can be used to establish consumption-based emissions from retail electric energy consumption. This includes NEPOOL GIS certificates the Company retires in its account and the NEPOOL GIS certificates that determine the residual mix. In light of this corrected response, the Company's understanding is that a further response to Data Request PUC 3-2 is unnecessary.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

PUC 3-3

Request:

Referencing National Grid's response to PUC 2-12d and e:

a. Does National Grid's own Base Case analysis of Rhode Island and the region, presented in this filing (e.g., Bates 331 to 332) show that there may be a regional shortage of RECs to meet all states' renewable energy standards (RES or RPS)?

b. If so, does National Grid believe that the Connecticut Alternative Compliance Payment will set the marginal REC price?

c. If so, does National Grid's response indicate that only the RPS in Connecticut will not be met in the Base Case through the retirement of eligible RECs?

d. If the answer to parts a-c are "yes," does National Grid's own Base Case analysis suggest that only consumption-based emissions in Connecticut can be improved in the Proposal Case? Why or why not?

Response:

a. No. An analysis of the Base Case indicates that all states' renewable energy standards are economically met through a combination of RECs from existing and planned class 1 compliant resources, plus Connecticut Alternative Compliance Payments (ACPs). A utility's decision to make ACPs, as opposed to building and/or purchasing RECs from new resources, is an economic decision. A utility's decision to make Connecticut ACPs does not necessarily mean that Connecticut has a shortfall of RECs, but it could imply that REC resources in CT may be meeting other states' requirements to allow for regional compliance through low-cost Connecticut ACPs.

b. Yes.

c. No. The retirement of eligible RECs will not lead to any state's inability to meets its RPS targets. Instead, the ENELYTIX computer modeling system will choose to supply the shortfall using the most economic replacement, which could be through RECs from RPS-compliant resources or through incremental ACPs, which, in this case, is incremental ACPs in Connecticut. However, the actual effect of retiring RECs will depend upon a number of factors such as the timing, quantity and location of retiring RECs.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

d. The Proposal Case evaluation demonstrates an ISO-New England (ISO-NE) wide reduction in greenhouse gas (GHG) emissions when compared to the Base Case, not only Connecticut. Applying a consumption-based emissions accounting approach will reduce each New England state's GHG emissions, based on their demand relative to the ISO-NE wide demand.

PUC 3-4

Request:

Referencing National Grid's Response to PUC 2-13:

a. Please re-file a response that is responsive to the question asked, namely for National Grid's RES obligation.

b. Please explain why National Grid believes the RES requirement is non-zero after the year 2035. Please reference R.I. Gen. Laws §39-26-4(a)(5) in the response.

c. Please re-file National Grid's original response but amend it with the following:

    i. Use black bars to indicate RECs from resources with PPAs that are operational,

    ii. Stack on top gray bars to indicate RECs from resources in the REG Program that are operational,

    iii. Stack on top red bars to indicate RECs expected from future REG-Program resources,

    iv. Stack on top orange bars to indicate RECs expected from resources with PPAs that are not yet operational,

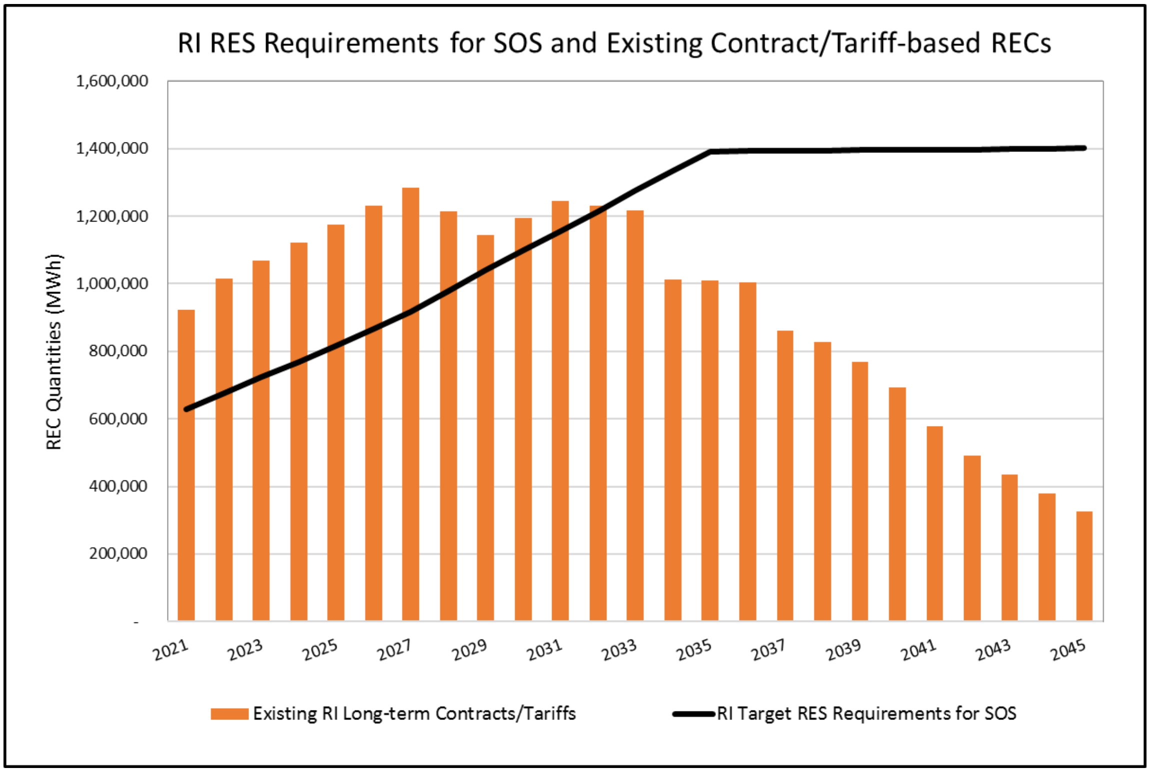
    v. Stack on top yellow bars to indicate RECs expected from the RFP issued pursuant to the PUC's decision in 4822, as National Grid provided in its December 9, 201 filing in Docket 4903,

    vi. Stack on top green bars to indicate RECs expected from the Revolution I,

    vii. Stack on top blue bars to indicate RECs expected from any other expected PPA or tariff program that transfers the REC product to National Grid.

Response:

a.



b. The Company's RES obligation from new renewable energy resources (RES) after the year 2035 is somewhat unclear at this time. As shown in the graph in the Company's response to Data Request PUC 2-13, the Company's current assumption is that its new RES obligation is not likely to be eliminated or become zero after the year 2035. Instead, the Company assumes that its obligation would continue at the same level as Compliance Year 2035 in the subsequent years.

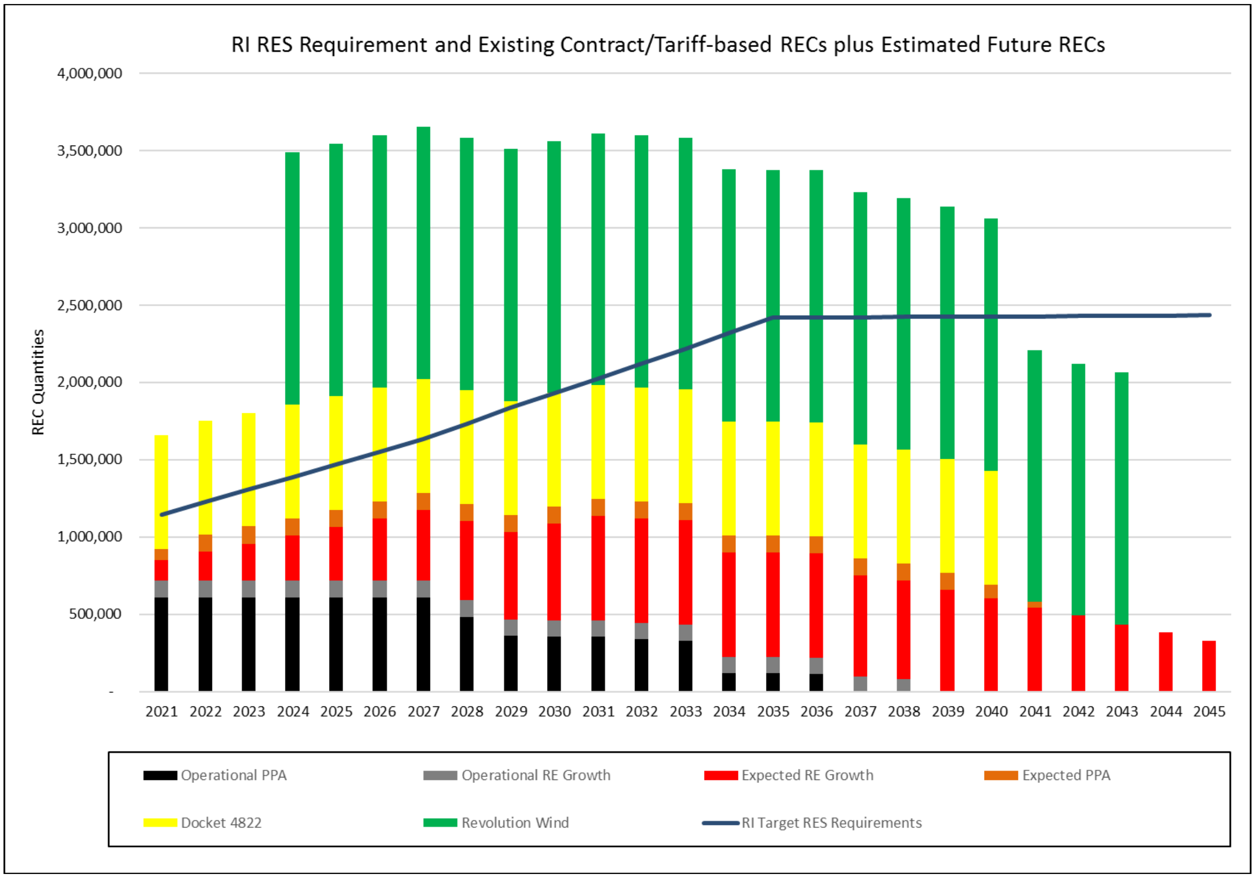
R.I. Gen. Laws § 39-26-4(a)(5) was repealed by legislation enacted in 2016. That provision had previously stated, "In 2020 and each year thereafter, the minimum renewable energy standard established in 2019 shall be maintained unless the commission shall determine that such maintenance is no longer necessary for either amortization of investments in new renewable energy resources or for maintaining targets and objectives for renewable energy." Thus, the need for the Commission's determination of the need for continuing the RES at the 2019 level in the year 2020 and beyond has been eliminated from the statute.

However, R.I. Gen. Laws § 39-26-4, "Renewable energy standard" provides that "(a) Starting in compliance year 2007, all obligated entities shall obtain at least three percent (3%) of the electricity they sell at retail to Rhode Island end-use customers, adjusted for electric line losses, from eligible renewable-energy resources, escalating, according to the following schedule: . . . (4) An additional one and one half percent (1.5%) of retail electricity sales in each of the following compliance years 2015, 2016, 2017, 2018 and 2019, and each year thereafter until 2035, provided that the commission has determined the adequacy, pursuant to §39-26-6, or potential adequacy of renewable-energy supplies to meet these percentage requirements." The Company assumes that, while the obligation does not increase in 2036 by 1.5%, the 2035 obligation of 36.5% would continue thereafter.

Neither the legislation nor the Commission's publications to date have expressly stated what the Company's obligations will be in 2036 and beyond, because the projections end at the year 2035.[1] As shown in "RES targets, by Compliance Year, for Both New and Existing Resources," footnote c, " R.I. Gen. Laws §§ 39-26-1 to 10, as amended, does not explicitly maintain a RES proportion in 2036 and thereafter." However, none of these sources have eliminated the RES obligation either. For these reasons, the Company's current assumption is that its RES obligations will most likely continue at the 2035 level (i.e., a total obligation of 38.5% including the 2% Existing obligation) in the year 2036 and beyond.

[1] See, e.g., "Rhode Island Renewable Energy Standard Annual RES Compliance Report for Compliance Year 2016," Figure 1, page 1, available at: http://www.ripuc.org/utilityinfo/2016%20RES%20Annual%20Compliance%20Report%20-%20final.pdf as well as "RES targets, by Compliance Year, for Both New and Existing Resources," available at: http://www.ripuc.org/utilityinfo/RES-Annual-Targets.pdf .

c.



Note: The RFP filed under Docket 4822 allows for selection up to 400 MW, which has been shown for illustrative purposes, assuming an equal mix of solar and wind.

PUC 3-5

Request:

Referencing the graph on Bates page 331, for the years 2021 through 2045, please plot the blue bars. In each year, please plot next to the blue bars the following stacked bars:

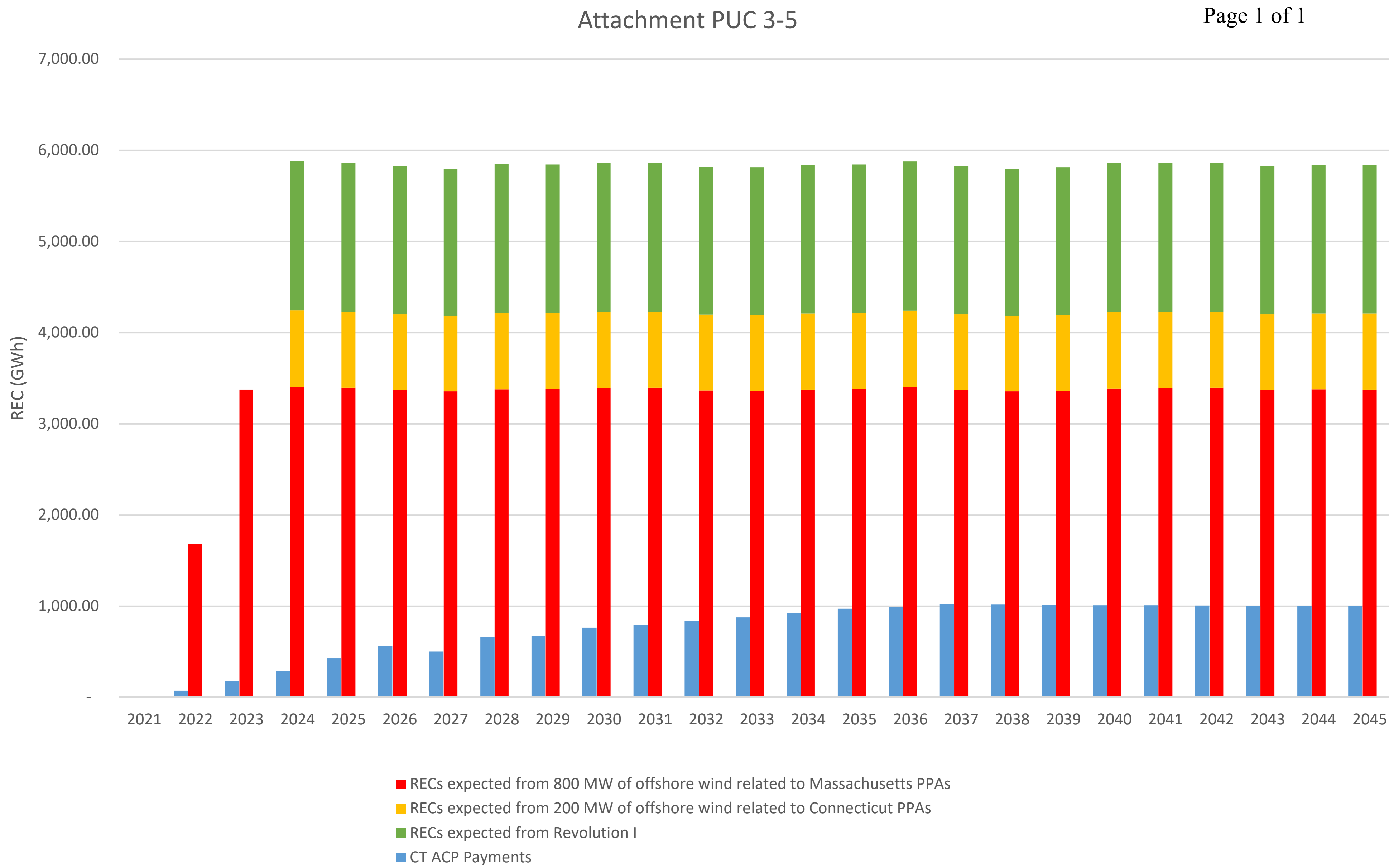
a. The lowest stack in red representing RECs expected from 800 MW of offshore wind related to Massachusetts PPAs included in the Proposal Case,

b. The middle stack in yellow representing RECs expected from 200 MW of offshore wind related to Connecticut PPAs included in the Proposal Case,

c. The top stack in green representing RECs expected from Revolution I.

Response:

Please refer to Attachment PUC 3-5 for the requested graph.



Note:
Expected RECs reported in this chart are based on projections for annual RECs as reported in the Proposal Case Enelytix market model

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PUC 3-6

Request:

Referencing Schedule NG-7 on Bates page 364 and Schedule NG-5 on Bates page 313:

a. For all categories that National Grid has described as "N/A" or not applicable, please indicate if the expected value for the category is zero.

b. For all categories that National Grid has described as "Applicable/not quantifiable," or "beyond the capabilities of the modeling system to quantify accurately," please indicate the direction ("positive" for net benefits, "negative" for net costs, or "unknown" if completely unknown) of each category. Please also indicate a magnitude for each category relative to the total net quantified benefits (for example, "small," "large," or "unknown").

Response:

a. Please refer to Attachment PUC 3-6.

b. Please refer to Attachment PUC 3-6.

Rhode Island Renewable Energy Long Term Contract RFP
Docket 4600 Benefit-Cost Framework - Applicable Category Summary

Power System Level (Cost/Benefit Categories)

	Category	Applicability	(NPV in 2018$)	Description of quantitative values or reason for exclusion:
(1)	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-	Applicable/Quantifiable	$933,754,251	Market value of Energy from Project + Increase in Project PPA market value from year with extreme Winter prices ocurring once in 15 years
(2)	Renewable Energy Credit Cost/Value	Applicable/Quantifiable	$430,227,231	Market value of Project RECs retired (used) for RES or sold
(3)	Retail Supplier Risk Premium	Not Applicable (N/A)	$0	PPA is a long term contract for wholesale power supply at a fixed price.
(4)	Forward Commitment: Capacity Value	Applicable/Not Quantifiable	-	Beyond the capabilities of the modeling system to quantify accurately. Neutral impact.
(5)	Forward Commitment: Avoided Ancillary Services Value	Applicable/Not Quantifiable	-	Beyond the capabilities of the modeling system to quantify accurately. Negative impact, insignificant.
(6)	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Applicable/Quantifiable	($1,333,945,342)	PPA cost of energy and RECs.
(7)	Electric Transmission Capacity Costs / Value	Applicable/Quantifiable	$0	The Proposal contains a fixed PPA price for energy and REC, with all interconnection and transmission upgrades included in PPA price. The project is commitment to interconnect to the ISO-NE "PTF" at the Capacity Capability Interconnection Standard, as defined by ISO-NE.
(8)	Electric transmission infrastructure costs for Site Specific Resources	Applicable/Quantifiable	$0	The Proposal contains a fixed PPA price for energy and REC, with all interconnection and transmission upgrades included in PPA price. The project is required to interconnect to the ISO-NE "PTF" at the Capacity Capability Interconnection Standard, as defined by ISO-NE.
(9)	Net risk benefits to utility system operations (generation, transmission, distribution)	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". This resource is not a DER.
(10)	Option value of individual resources	Applicable/Quantifiable	$115,668,599	RI Energy Market Price Change Impact + REC Market Price Change Impact + Benefit to Rhode Island Gas Customers due to Gas Use Reduction
(11)	Investment under Uncertainty: Real Options Cost / Value	Applicable/Quantifiable	Included in categories (1,2,6,10)	Project was selected based on a competitive process of multiple proposals. Evaluation and benefit cost analysis was compared to a basecase that provided a "but for" or "counterfactual" projection of the costs of electric energy, RECs, and carbon emissions associated with Rhode Island electricity consumption under a future in which no proposals are selected.
(12)	Energy Demand Reduction Induced Price Effect	N/A	$0	Generation supply is not an Energy DRIPE, but the proposal's indirect benefit impact on market LMP price change and REC price change is listed above.
(13)	Greenhouse gas compliance costs (Embedded Cost)	Applicable/Quantifiable	Included in category (1)	Greenhouse gas compliance costs (RGGI) is embedded as a fuel related cost in the model analysis to determine the quantitative market impacts listed above.
(14)	Criteria air pollutant and other environmental compliance costs	Applicable/Not quantifiable	-	Not significant value to quantify or differentiate between projects
(15)	Innovation and Learning by Doing	Applicable/Not quantifiable	-	The benefits of innovation in the OSW industry and by the developer have been captured in the bid pricing of the contract, including, but not limited to any potential federal tax credits, economies of scale, and first mover advantage. Postive impact, significant.
(16)	Distribution capacity costs	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(17)	Distribution delivery costs	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(18)	Distribution system safety loss/gain	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(19)	Distribution system performance	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(20)	Utility low income	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(21)	Distribution system and customer reliability / resilience impacts	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(22)	Distribution system safety loss/gain	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.

Customer Level (Cost/Benefit Categories)

(23)	Program participant / prosumer benefits / costs	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(24)	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(25)	Low-Income Participant Benefits	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(26)	Consumer Empowerment & Choice	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(27)	Non-participant (equity) rate and bill impacts	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.

Societal Level (Cost/Benefit Categories)

(28)	Greenhouse gas externality costs	Applicable/Quantifiable	$533,172,942	Impact of Reduction in GHG Emissions
(29)	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$10,761,161	Impact of Reduction in NOx Emissions
(30)	Conservation and community benefits	Applicable/Not quantifiable	-	The project must obtain all required federal, state and local permits. This categeory calls for consideration of land use impacts, including loss of carbon sink, habitat, historical value, and sense of place, as well as the equity in distribution of harmful or nuisance infrastructure. DWW explained how it intends to minimize land use impacts, including through the federal, state and local permitting process, in Section 6 of its bid related to siting and zoning, and Section 7 of its bid related to environmental assessments and permitting. Any associated costs not mitigated through applicable permitting processes are not quantifiable at this time. Negative impact, unknown magnitude.
(31)	Non-energy costs/benefits: Economic Development	Applicable/Quantifiable	$405,125,090	Economic Benefit to Rhode Island
(32)	Innovation and knowledge spillover	Applicable/Not quantifiable	-	Rhode Island's leadership and contribution to emerging off-shore wind industry brings opportunities to drive down costs, attract future development, increase diversity of clean energy supply, and encourage a clean energy economy bringing investment and jobs to the region. Additional value brought by DWW's experience developing off-shore wind in the US and opportunity to take advantage of expiring federal tax incentives, economies of scale, and first mover advantage. Positive impact, large.
(33)	Societal Low-Income Impacts	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(34)	Public Health	Applicable/Not quantifiable	Included in category (28) and (29)	Navigant Report (Schedule NG-6), "Pollutants emitted by the electric power sector cause damage to human health, including increased morbidity and mortality. Over the course of its operating life, the Revolution Wind Rhode Island project will displace thermal generation which will result in reduced emissions of harmful pollutants, which can be translated to societal benefits". The societal benefits for GHG and NOx emissions reduction are listed above in (28) and (29). Positive impact, significant.
(35)	National Security and US international influence	Applicable/Not quantifiable	Included in category (1) and (28)	The project will contribute to reducing oil consumption, attributed to winter fuel switching, by approximately 270,000 Bbls. The economic and environmental impacts have been captured in the market value and GHG emission reduction listed in (1) and (28). Positive impact, small.

Total Net Benefits:	**$1,094,763,932**

PUC 3-7

Request:

Referencing Schedule NG-7 on Bates page 364 and Schedule NG-5 on Bates page 313:

a. Does National Grid believe the entire cost of the proposal in 2018$ is $1,333,945,342 or is National Grid reporting the program costs?

b. If National Grid is only reporting the program costs, please explain why the total costs of the Facility and related facilities, and all other costs associated with the PPA are not included in Schedule NG-7 and Schedule NG-5. Please specifically include an explanation of why the direct cost of the project does not include transmission.

c. Please provide National Grid's estimate for the following:

    i. costs of the Delivery Facility including financing costs, all associated system upgrades, operations and maintenance (O&M) costs, decommissioning costs, sitting and permitting costs, other legal and regulatory costs, administrative costs not captured in O&M costs, and any other costs associated with the construction and operation of the Delivery Facility;

    ii. costs of the Facility including financing costs, all associated operations and maintenance (O&M) costs, decommissioning costs, sitting and permitting costs, other legal and regulatory costs, administrative costs not captured in O&M costs, and any other costs associated with the construction and operation of the Delivery Facility, excluding sunk costs such as the costs associated with the RFP and the current proceeding;

    iii. projected losses of entities (inside and outside of Rhode Island) that sell (or otherwise monetize) energy and renewable energy products that will have reduced value because of the effect National Grid expects the Facility will have on markets for these products, including National Grid's own products purchased through Long-Term Contracting Standard for Renewable Energy, Distributed Generation Standard Contracts, and Renewable Energy Growth Program;

    iv. any administrative costs to National Grid for related to cost recovery and marketing products from the facility not included above;

v. costs and benefits to local tourism and businesses, in particular, any costs or benefits to commercial fishing, that are not captured in the "Economic Benefit to Rhode Island" category;

vi. environmental costs and benefits, including wildlife impact, not included in the societal impact of greenhouse gas and NOx emissions;

d. If National Grid does not have information responsive to parts c.i and c.ii, please provide National Grid's estimate for all revenues, including the PPA revenue, that are necessary to support the construction and operation of the Facility and Delivery Facility, and that will be ultimately paid for by entities other than DWW (e.g., taxpayers supporting an investment tax credit and ratepayers supporting Forward Capacity Market revenue).

e. Please update the RI Test for the proposal using information responsive to parts c and d.

Response:

a. $1,333,945,342 is the net present value of the total contract cost for energy and RECs for the entire contract term in 2018$. The Narragansett Electric Company (Narragansett) will only pay the fixed contract costs subject to the terms and conditions under the power purchase agreement and is not responsible to make any payments otherwise.

b. The total cost of the project, including the generating facility and the facilities required for delivery are included in the "all-in" contract price, as bid by DWW. Narragansett will only pay the fixed contract price for the energy and RECs for the contract term. Narragansett will not have any other direct costs under the contract.

c.

i. Narragansett will pay a fixed contract price for the energy and RECs and does not have this information.

ii. Narragansett will pay a fixed contract price for the energy and RECs and does not have this information.

iii. National Grid is currently working with its consultant in an attempt to quantify additional costs and benefits, and aims to provide this information as soon as practicable, likely in supplemental testimony to be submitted April 22, 2019.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

iv. National Grid does not have an estimate on incremental administrative costs administrative costs related to cost recovery and marketing products from the facility that may arise from the contract at this time.

v. National Grid does not have information sufficient to develop such an estimate.

vi. National Grid does not have information sufficient to develop such an estimate.

d. National Grid does not have information sufficient to develop such an estimate.

e. Please see National Grid's responses to parts c and d of this Data Request, above. National Grid does not have information with which to update the RI Test, at this time.

PUC 3-8

Request:

Please explain how the extreme winter pricing was modeled, including explaining the following:

a. Which months make up the months of extreme winter pricing?

b. Please provide the market conditions and/or fuel prices that were used to effectuate the extreme winter pricing.

c. In how many hours and days did extreme pricing occur?

d. Was LMP calculated during these hours under extreme winter pricing inputs, or was an extreme pricing markup added to the model LMP to effectuate extreme winter pricing?

e. What is the average monthly LMP of extreme winter pricing compared to non-extreme winter pricing? Please also provide the associated average fuel prices that are relevant to the marginal pricing in the model and actual extreme winter pricing events.

Response:

All quantitative analysis except for the extreme winter price metric were developed using input assumptions, forecasts and projections under normal operating conditions (weather normalized forecasts). The Base Case and Proposal Case ENELYTIX energy market models use these inputs to compute the hourly nodal LMPs for the ISO-NE footprint over the evaluation period. These inputs include TCR's *baseline* projections for fuel gas and fuel oil prices that were developed assuming normal conditions.

a. The extreme winter pricing case is a sensitivity analysis of the Proposal Case. This sensitivity analysis assumes that, for a representative power year (2024/25), the winter months of December, January and February experience extremely high spot gas and fuel oil prices. For extreme winter pricing case, the ENELYTIX energy market model computes the hourly nodal LMPs based on *revised* projections for fuel gas and fuel oil prices, representative of prices under extreme winter conditions. The winter event and revised prices are assumed to prevail over the entirety of the representative winter period. The months included in the extreme winter pricing case were December 1, 2024 through February 28, 2025.

b. TCR produced revised projections for fuel gas and fuel oil by first reviewing historical fuel prices over the past fifteen winter periods to quantify the average price markups for fuel gas and fuel oil experienced in New England during the polar vortex event of winter 2013/14. TCR then applied these markups to their baseline projections for fuel prices in the extreme winter pricing model. This analysis is provided in Attachment PUC 3-8-1.

c. As stated above, for the extreme winter pricing case, the ENELYTIX energy market model computes the hourly nodal LMPs based on revised projections for fuel gas and fuel oil prices, representative of prices under extreme winter conditions. The revised projections for fuel prices were applied over a period of 90 days or 2,160 hours starting December 1, 2024 through February 28, 2025. The resulting extreme winter prices i.e. impact on LMPs due to revised fuel prices were also analyzed over the same period of time.

d. TCR uses this sensitivity case to evaluate the "*Increase in Project PPA market value from year with extreme Winter fuel prices occurring once in 15 years*" metric in the following steps:
    1. TCR first calculates the total energy market value of proposal energy for the full representative power year (2024/25) under the Proposal Case
    2. TCR calculates the total energy market value of proposal energy for the full representative power year (2024/25) under the extreme winter pricing case, which assumes extreme fuel prices
    3. TCR calculates the change in energy market value as the difference between the values calculates in steps 1 and 2, above.
    4. This incremental change in proposal annual energy market value is then expressed as a percentage of the annual energy market value in the Proposal Case by dividing the value obtained in step 3, above, by the value obtained in step 1, above (e.g., 40%).
    5. TCR assumes that a year with such extreme three-month gas prices would occur once in fifteen years which reflected as a 1/15 probability of occurrence in each year of evaluation
    6. TCR then calculates the metric in each year as the percentage impact in the year of occurrence calculated in step 4, above (e.g., 40%), multiplied by the assumed frequency of occurrence, (i.e., 1/15) and then multiplied by the annual energy market value of the proposal that year.

e. Attachment PUC 3-8-2 (Confidential) provides a comparison of the average LMPs by zone during the extreme winter period between the Proposal Case and the extreme winter case.

   Attachment PUC 3-8-3 (Confidential) provides the input fuel prices for fuel gas (sub-attachment A) and fuel oil (sub-attachment B) that were used for the Proposal and Base Case model. The fuel gas prices are assumed to be increased by 100% and fuel oil prices are assumed to be increased by 50% for the extreme winter case, based on an approximation of TCR's analysis, provided above.

1. Fuel Gas Analysis

1.1 Historical monthly average gas price of Algon Gates (nominal $/MMBTU), Source: S&P Market Intelligence

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jan	$ 8.6	$ 12.1	$ 11.3	$ 9.5	$ 7.9	$ 11.2	$ 9.0	$ 7.6	$ 8.4	$ 4.8	$ 11.8	$ 23.3	$ 9.6	$ 4.3	$ 4.9	$ 18.2
Feb	$ 10.3	$ 6.4	$ 7.2	$ 8.5	$ 10.4	$ 10.5	$ 6.0	$ 6.5	$ 6.4	$ 3.5	$ 16.8	$ 19.8	$ 17.2	$ 3.7	$ 3.9	$ 5.3
Mar	$ 8.0	$ 6.0	$ 7.9	$ 7.8	$ 8.5	$ 10.4	$ 4.8	$ 4.8	$ 5.3	$ 2.8	$ 7.2	$ 14.1	$ 8.1	$ 1.9	$ 4.6	$ 4.0
Apr	$ 6.0	$ 6.3	$ 7.8	$ 7.7	$ 8.6	$ 11.0	$ 4.1	$ 4.4	$ 4.7	$ 2.5	$ 5.1	$ 4.9	$ 3.4	$ 2.9	$ 3.2	$ 5.3
May	$ 6.2	$ 6.8	$ 7.0	$ 6.8	$ 8.3	$ 12.1	$ 4.1	$ 4.5	$ 4.6	$ 2.6	$ 4.5	$ 4.0	$ 2.0	$ 2.1	$ 3.2	$ 2.4
Jun	$ 6.3	$ 6.7	$ 7.7	$ 6.8	$ 8.0	$ 13.6	$ 4.0	$ 5.2	$ 5.0	$ 3.5	$ 4.4	$ 4.2	$ 1.8	$ 2.3	$ 2.5	$ 2.7
Jul	$ 5.5	$ 6.4	$ 8.1	$ 6.9	$ 6.9	$ 12.5	$ 3.7	$ 5.1	$ 5.5	$ 3.8	$ 4.6	$ 3.2	$ 2.0	$ 2.8	$ 2.6	$ 2.9
Aug	$ 5.4	$ 5.8	$ 10.1	$ 8.0	$ 7.0	$ 8.9	$ 3.6	$ 4.8	$ 4.4	$ 3.5	$ 3.5	$ 2.7	$ 2.3	$ 3.2	$ 2.4	$ 3.2
Sep	$ 5.0	$ 5.4	$ 12.7	$ 5.5	$ 6.5	$ 8.1	$ 3.2	$ 4.3	$ 4.2	$ 3.5	$ 3.8	$ 3.2	$ 2.8	$ 2.8	$ 1.9	$ 2.9
Oct	$ 5.2	$ 6.6	$ 14.4	$ 6.3	$ 7.3	$ 7.4	$ 4.5	$ 3.9	$ 4.0	$ 3.8	$ 3.9	$ 3.0	$ 3.5	$ 2.4	$ 2.9	$ 3.3
Nov	$ 5.1	$ 6.7	$ 10.8	$ 7.9	$ 7.9	$ 7.6	$ 4.0	$ 4.6	$ 4.0	$ 7.1	$ 5.5	$ 6.4	$ 3.0	$ 2.6	$ 3.5	
Dec	$ 6.9	$ 7.6	$ 14.2	$ 7.5	$ 11.6	$ 7.4	$ 6.9	$ 8.1	$ 4.1	$ 5.9	$ 12.8	$ 5.7	$ 2.2	$ 7.3	$ 9.2	

1.2 Winter period averages (December / January / February)

Winter of	2003 / 2004	2004 / 2005	2005 / 2006	2006 / 2007	2007 / 2008	2008 / 2009	2009 / 2010	2010 / 2011	2011 / 2012	2012 / 2013	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018
Average winter Price ($/MMBTU)	$ 8.47	$ 8.70	$10.73	$ 8.61	$11.11	$ 7.48	$ 6.99	$ 7.62	$ 4.15	$11.51	$18.64	$10.85	$ 3.40	$ 5.38	$10.90

1.3 Calculations

Average price over 15 Years	$ 8.97
Price in 2013/2014	$18.64
Markup over Average	108%

2. Fuel Oil Analysis

2.1 Historical monthly average gas price of Distillate Oil (nominal $/MMBTU), Source: EIA/Thomson Reuters

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jan	$ 6.5	$ 7.0	$ 9.4	$ 12.6	$ 10.9	$ 18.4	$ 10.5	$ 14.6	$ 18.7	$ 21.8	$ 22.0	$ 22.0	$ 11.7	$ 6.8	$ 11.1	$ 14.5
Feb	$ 8.1	$ 6.6	$ 9.7	$ 11.8	$ 12.2	$ 18.9	$ 9.2	$ 14.2	$ 19.8	$ 22.9	$ 22.8	$ 22.1	$ 13.5	$ 7.0	$ 11.2	$ 13.3
Mar	$ 7.1	$ 6.5	$ 11.2	$ 12.7	$ 12.5	$ 21.9	$ 9.2	$ 14.9	$ 21.8	$ 23.1	$ 21.1	$ 21.0	$ 11.7	$ 8.2	$ 10.7	$ 13.4
Apr	$ 5.7	$ 6.6	$ 11.0	$ 14.2	$ 13.4	$ 23.2	$ 9.8	$ 15.8	$ 23.0	$ 22.6	$ 19.6	$ 20.7	$ 12.3	$ 8.5	$ 10.9	$ 14.6
May	$ 5.3	$ 7.3	$ 10.1	$ 14.1	$ 13.5	$ 26.0	$ 10.6	$ 14.7	$ 21.2	$ 20.9	$ 19.7	$ 20.5	$ 13.2	$ 9.7	$ 10.4	$ 15.7
Jun	$ 5.4	$ 7.1	$ 11.6	$ 13.8	$ 14.2	$ 27.3	$ 12.5	$ 14.6	$ 21.3	$ 18.8	$ 19.7	$ 20.7	$ 12.6	$ 10.1	$ 9.6	$ 15.1
Jul	$ 5.6	$ 7.8	$ 11.8	$ 14.0	$ 14.9	$ 27.2	$ 11.7	$ 14.2	$ 22.0	$ 20.2	$ 20.7	$ 19.9	$ 11.2	$ 9.3	$ 10.2	$ 15.1
Aug	$ 5.9	$ 8.4	$ 12.9	$ 14.2	$ 14.2	$ 22.7	$ 13.3	$ 14.5	$ 21.1	$ 21.8	$ 21.2	$ 19.8	$ 10.0	$ 9.5	$ 10.9	$ 15.2
Sep	$ 5.3	$ 9.0	$ 14.0	$ 12.3	$ 15.5	$ 21.0	$ 12.3	$ 15.0	$ 21.0	$ 22.6	$ 21.3	$ 18.9	$ 10.2	$ 9.6	$ 12.3	$ 16.0
Oct	$ 5.9	$ 10.7	$ 13.6	$ 11.8	$ 16.4	$ 16.1	$ 13.8	$ 16.1	$ 21.2	$ 22.5	$ 21.1	$ 17.4	$ 10.1	$ 10.7	$ 12.3	$ 16.6
Nov	$ 6.0	$ 10.0	$ 12.1	$ 11.8	$ 18.6	$ 13.2	$ 14.1	$ 16.6	$ 21.9	$ 21.6	$ 21.0	$ 16.1	$ 9.5	$ 9.9	$ 13.1	
Dec	$ 6.4	$ 9.2	$ 12.2	$ 12.1	$ 18.5	$ 10.0	$ 14.1	$ 17.7	$ 20.7	$ 21.5	$ 21.8	$ 13.3	$ 7.4	$ 11.1	$ 13.4	

2.2 Winter period averages (December / January / February)

Winter of	2003 / 2004	2004 / 2005	2005 / 2006	2006 / 2007	2007 / 2008	2008 / 2009	2009 / 2010	2010 / 2011	2011 / 2012	2012 / 2013	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018
Average winter Price ($/MMBTU)	$ 6.65	$ 9.41	$12.18	$11.74	$18.56	$ 9.89	$14.30	$18.75	$21.83	$22.09	$21.93	$12.80	$ 7.06	$11.17	$13.73

1.3 Calculations

Average price over 15 Years	$14.14
Price in 2013/2014	$21.93
Markup over Average	55%

Average monthly LMPs by load zone reported by ENELYTIX over the winter period

	CT	NMABO	SEMA	WCMA	ME	NH	RI	VT
Proposal Case								
Dec-2024	[redacted]							
Jan-2025								
Feb-2025								
Average over Win								
Extreme winter pricing case								
Dec-2024	[redacted]							
Jan-2025								
Feb-2025								
Average over Win								

Attachment A

Attachment A
NewEngland

Month	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone 6
11/2018	[redacted]			
12/2018				
1/2019				
2/2019				
3/2019				
4/2019				
5/2019				
6/2019				
7/2019				
8/2019				
9/2019				
10/2019				
11/2019				
12/2019				
1/2020				
2/2020				
3/2020				
4/2020				
5/2020				
6/2020				
7/2020				
8/2020				
9/2020				
10/2020				
11/2020				
12/2020				
1/2021				
2/2021				
3/2021				
4/2021				
5/2021				
6/2021				
7/2021				
8/2021				
9/2021				
10/2021				
11/2021				
12/2021				
1/2022				
2/2022				
3/2022				
4/2022				
5/2022				
6/2022				
7/2022				
8/2022				
9/2022				
10/2022				
11/2022				

Attachment A
NewEngland

Month	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone 6
12/2022	[redacted]			
1/2023	[redacted]			
2/2023	[redacted]			
3/2023	[redacted]			
4/2023	[redacted]			
5/2023	[redacted]			
6/2023	[redacted]			
7/2023	[redacted]			
8/2023	[redacted]			
9/2023	[redacted]			
10/2023	[redacted]			
11/2023	[redacted]			
12/2023	[redacted]			
1/2024	[redacted]			
2/2024	[redacted]			
3/2024	[redacted]			
4/2024	[redacted]			
5/2024	[redacted]			
6/2024	[redacted]			
7/2024	[redacted]			
8/2024	[redacted]			
9/2024	[redacted]			
10/2024	[redacted]			
11/2024	[redacted]			
12/2024	[redacted]			
1/2025	[redacted]			
2/2025	[redacted]			
3/2025	[redacted]			
4/2025	[redacted]			
5/2025	[redacted]			
6/2025	[redacted]			
7/2025	[redacted]			
8/2025	[redacted]			
9/2025	[redacted]			
10/2025	[redacted]			
11/2025	[redacted]			
12/2025	[redacted]			
1/2026	[redacted]			
2/2026	[redacted]			
3/2026	[redacted]			
4/2026	[redacted]			
5/2026	[redacted]			
6/2026	[redacted]			
7/2026	[redacted]			
8/2026	[redacted]			
9/2026	[redacted]			
10/2026	[redacted]			
11/2026	[redacted]			
12/2026	[redacted]			

Attachment A
NewEngland

Month	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone 6
1/2027	[redacted]			
2/2027	[redacted]			
3/2027	[redacted]			
4/2027	[redacted]			
5/2027	[redacted]			
6/2027	[redacted]			
7/2027	[redacted]			
8/2027	[redacted]			
9/2027	[redacted]			
10/2027	[redacted]			
11/2027	[redacted]			
12/2027	[redacted]			
1/2028	[redacted]			
2/2028	[redacted]			
3/2028	[redacted]			
4/2028	[redacted]			
5/2028	[redacted]			
6/2028	[redacted]			
7/2028	[redacted]			
8/2028	[redacted]			
9/2028	[redacted]			
10/2028	[redacted]			
11/2028	[redacted]			
12/2028	[redacted]			
1/2029	[redacted]			
2/2029	[redacted]			
3/2029	[redacted]			
4/2029	[redacted]			
5/2029	[redacted]			
6/2029	[redacted]			
7/2029	[redacted]			
8/2029	[redacted]			
9/2029	[redacted]			
10/2029	[redacted]			
11/2029	[redacted]			
12/2029	[redacted]			
1/2030	[redacted]			
2/2030	[redacted]			
3/2030	[redacted]			
4/2030	[redacted]			
5/2030	[redacted]			
6/2030	[redacted]			
7/2030	[redacted]			
8/2030	[redacted]			
9/2030	[redacted]			
10/2030	[redacted]			
11/2030	[redacted]			
12/2030	[redacted]			
1/2031	[redacted]			

Attachment A
NewEngland

Month	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone 6
2/2031	[redacted]			
3/2031				
4/2031				
5/2031				
6/2031				
7/2031				
8/2031				
9/2031				
10/2031				
11/2031				
12/2031				
1/2032				
2/2032				
3/2032				
4/2032				
5/2032				
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12/2032				
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8/2034				
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10/2034				
11/2034				
12/2034				
1/2035				
2/2035				

Attachment A
NewEngland

Month	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone 6
3/2035	[redacted]			
4/2035				
5/2035				
6/2035				
7/2035				
8/2035				
9/2035				
10/2035				
11/2035				
12/2035				
1/2036				
2/2036				
3/2036				
4/2036				
5/2036				
6/2036				
7/2036				
8/2036				
9/2036				
10/2036				
11/2036				
12/2036				
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11/2037				
12/2037				
1/2038				
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10/2038				
11/2038				
12/2038				
1/2039				
2/2039				
3/2039				

Attachment A
NewEngland

Month	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone 6
4/2039	[redacted]			
5/2039				
6/2039				
7/2039				
8/2039				
9/2039				
10/2039				
11/2039				
12/2039				
1/2040				
2/2040				
3/2040				
4/2040				
5/2040				
6/2040				
7/2040				
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10/2040				
11/2040				
12/2040				
1/2041				
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11/2041				
12/2041				
1/2042				
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4/2042				
5/2042				
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11/2042				
12/2042				
1/2043				
2/2043				
3/2043				
4/2043				

REDACTED

Attachment A
NewEngland

Month	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone 6
5/2043	[redacted]			
6/2043				
7/2043				
8/2043				
9/2043				
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11/2043				
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11/2045				
12/2045				
1/2046				
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11/2046				
12/2046				
1/2047				
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3/2047				
4/2047				
5/2047				

Attachment A
NewEngland

Month	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone 6
6/2047	[redacted]			
7/2047				
8/2047				
9/2047				
10/2047				
11/2047				
12/2047				
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11/2050				
12/2050				

Attachment B

Attachment B
Distillate and Residual Prices to Electric Power Plants (2018$/MMBtu)

	New England (1)		New York (2)	
Year	Distillate	Residual	Distillate	Residual
	2018$ /MMbtu	2018$ /MMbtu	2018$ /MMbtu	2018$ /MMbtu
2018	[redacted]			
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
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2046				
2047				
2048				
2049				
2050				

Sources/ Notes

1 AEO 2018 Energy Prices Electric Power (Case Reference case Region New England), 2017$

2 AEO 2018 Energy Prices Electric Power (Case Reference case Region Middle Atlantic), 2017$
3 inflator from 2017$ to 2018$ **1.02**

PUC 3-9

Request:

Please provide the appropriate statistical relevance of the extreme winter pricing, as modeled. For example, is it "one-in-fifteen-year winter pricing?"

a. Please explain if, and how, this statistical relevance was used to effectuate the event of extreme winter pricing in the model—or explain that the model simply forced an extreme winter event in a certain model winter.

b. Please compare the historical actual price associated with a winter that has the same statistical relevance as the extreme winter pricing model event?

c. Please explain if historical average winter prices should already have events like actual extreme winter pricing included in a statistically valid way.

d. Please explain why the energy and pricing model outputs would not already sufficiently capture the effect of extreme events (such as the extreme winter pricing model event) in projected average prices—for example, were fuel price and demand inputs not based in part on historical pricing?

e. Please list all historical data that was used in the model (such as CELT data, Henry Hub market prices, etc.).

Response:

a. A 1 in 15 chance of the extreme winter price event occurring is statistically effectuated in the model by assuming that there is a 1/15 probability of this event occurring in each year of evaluation and is accounted for in the metric calculation. Please refer to the Company's response to Data Request PUC 3-8 for additional details on the calculation of the extreme winter price case and metric.

b. TCR analyzed historical fuel prices over the last 15 winter periods to determine the relative increase in fuel prices associated with the 2014 polar vortex event in New England. The results of this analysis were used to determine the fuel prices applied to the extreme winter pricing model event and are therefore comparable. Please refer to the Company's response to Data Request PUC 3-8 and Attachment PUC 3-8-1.

c. Historical average winter prices are based on actual reported prices, including prices caused by extreme winter events.

d. Energy and pricing model outputs produced by the ENELYTIX system are based on input assumptions, forecasts and projections that assume normal operating conditions (weather normalized). For example, TCR uses load projections from the ISO-New England Inc. (ISO-NE) 2018 CELT Report. The CELT report categorically reports projections for "Expected weather case (50^{th} percentile)" or 50/50 load as opposed to "extreme weather case (90^{th} percentile)" or 90/10 load. TCR uses 50/50 projections in its forecast, which does not capture the impact of extreme events. Similarly, gas price forecasts from the United States Energy Information Administration (EIA) Annual Energy Outlook are based on years with normal weather, not extreme winter weather.

e. TCR used the following historical data sources in its model, which formed the basis for its projections about future conditions:

- Previous ISO New England CELT Reports and Forecasts;
- Results of previous ISO New England Forward Capacity Auctions;
- Hourly renewable resource generation profiles from National Renewable Energy Laboratories; and
- Historical fuel prices reported by EIA and Standard & Poors Market Intelligence, including prices from Henry Hub, to derive winter fuel switching assumptions and extreme winter pricing assumptions.

PUC 3-10

Request:

What discount rate (time value of money) was used in the energy market and economic models and in any results presented in the filing?

Response:

The quantitative metric evaluation uses a real discount rate of 4.892% and a nominal discount rate of 6.990% to calculate the corresponding net present values (NPV) of annual revenues, costs and energy that are reported in the ENELYTIX energy market models. All financial parameters used in the energy market models and subsequent quantitative analysis are in real 2018 dollars based a 2% rate of inflation.

The real and nominal discount rates used in the analysis are linked by the following:

$$DR_R = \frac{(1 + DR_N)}{(1 + R_I)} - 1$$

Where,

$DR_R = Real\ Discount\ rate$
$DR_N = Nominal\ Discount\ rate$
$R_I = Rate\ of\ inflation$

The analysis results in real 2018 dollars are presented in Schedule NG-5 at Bates pages 311 and 313.

PUC 3-11

Request:

Please recalculate the results and benefits and costs of the energy market and economic models assuming 1%, 3% and 7% discount rates. Please provide graphs of the annual PPA above- or below-market costs using these discount rates and the rate used in the filing.

Response:

Please refer to Attachment PUC 3-11-1, for a summary of results and benefits and costs of energy market models assuming 1%, 3% and 7% discount rates as presented in Schedule NG-5, at Bates page 311 and 313.

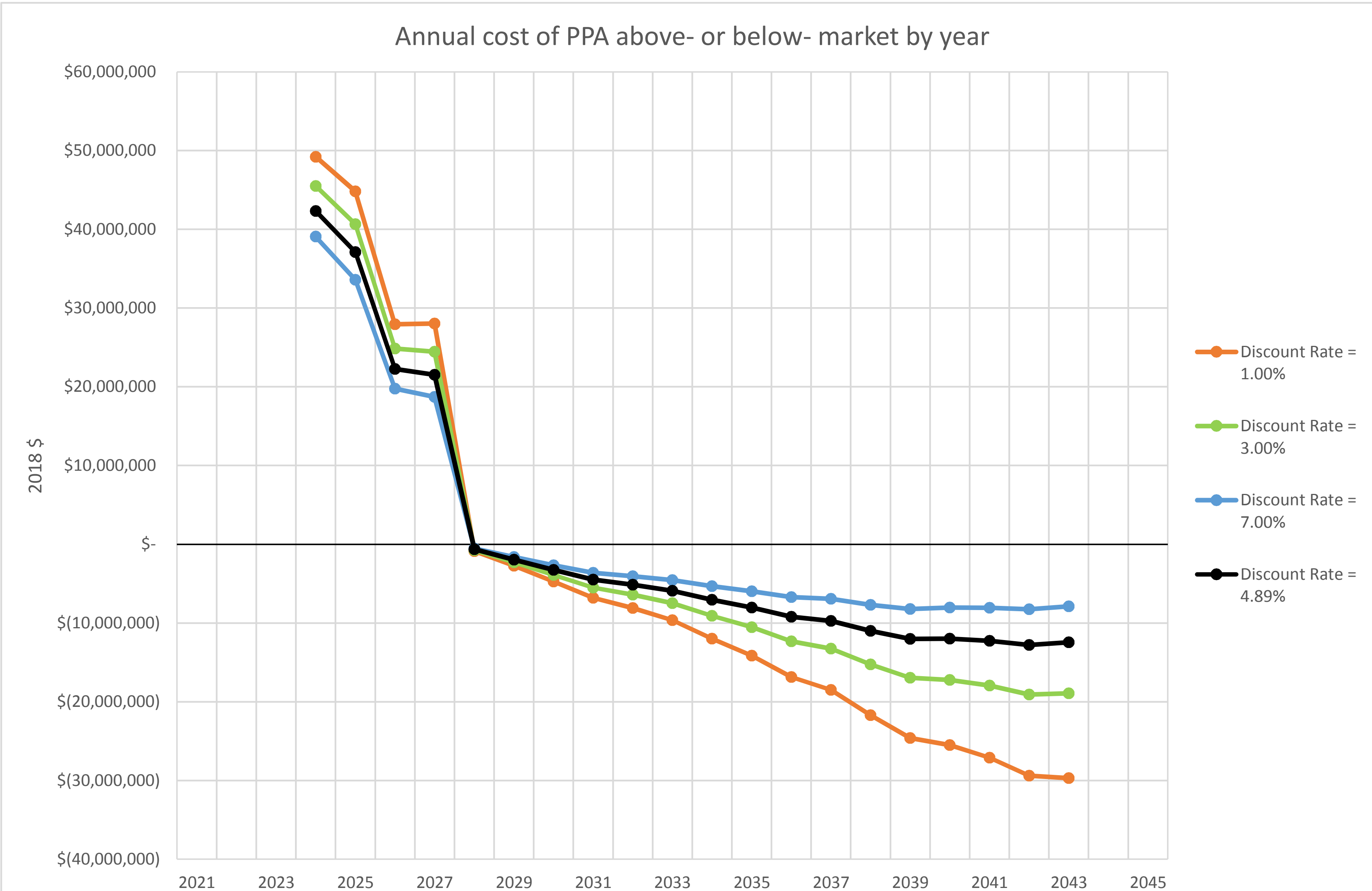
Please refer to Attachment PUC 3-11-2 for a graph of the annual PPA above- or below-market cost in each year using these discount rates and the rate used in the filing.

Quantitative Results, 2018$ / MWh

Discount Rate Assumed	1.00%	3.00%	4.89%	7.00%
Proposal Details (From CPPD)				
Resource Type	Off Shore Wind	Off Shore Wind	Off Shore Wind	Off Shore Wind
Contract Maximum Amount (MW)	400	400	400	400
Project Net Capacity Factor (%)	0.466	0.466	0.466	0.466
Proposed Annual Delivery (MWh)	1633252.216	1633252.216	1633252.216	1633252.216
Storage Included	No	No	No	No
PPA Start Date	1/1/2024	1/1/2024	1/1/2024	1/1/2024
PPA End Date	12/31/2043	12/31/2043	12/31/2043	12/31/2043
Term (years)	20	20	20	20
ISO-NE Load Zone	4005 .Z.RHODEISLAND	4005 .Z.RHODEISLAND	4005 .Z.RHODEISLAND	4005 .Z.RHODEISLAND
Quantitative Metric Summary	**2018$/MWh**	**2018$/MWh**	**2018$/MWh**	**2018$/MWh**
D.1 Direct Metrics				
Direct Cost of Project Energy	$ 53.61	$ 54.30	$ 54.92	$ 55.58
Direct Cost of Project RECs	$ 19.75	$ 20.00	$ 20.23	$ 20.48
Sub total - Direct Cost of Project Energy + RECs	**$ 73.36**	**$ 74.30**	**$ 75.16**	**$ 76.06**
Market Value of Energy from Project	$ 51.92	$ 51.53	$ 51.18	$ 50.83
Value of Project RECs used for RPS (Qty of RECs * Base Case REC price avoided)	$ 17.89	$ 17.06	$ 16.30	$ 15.47
Value of Project RECs sold out of state (Qty of RECs * Proposal Case REC price)	$ 7.15	$ 7.58	$ 7.94	$ 8.28
Direct Benefit of Project Energy + RECs	**$ 76.96**	**$ 76.17**	**$ 75.42**	**$ 74.57**
Total Net Direct Benefit (Cost) of Project	$ 3.59	$ 1.87	$ 0.26	$ (1.49)
D.2 Indirect Metrics [1]				
RI Energy Market Price Change Impact = Change in Annual Energy Market Value to EDC Load / Proposal Energy	$ 4.86	$ 4.88	$ 4.90	$ 4.91
Class 1 REC Market Price Change Impact = Quantity of RECs acquired at market price for EDC distribution load * Change in REC Market Price / Proposal Energy	$ -	$ -	$ -	$ -
Total Net Indirect Benefit (Cost)	$ 4.86	$ 4.88	$ 4.90	$ 4.91
D.3 Total of Direct and Indirect Metrics				
Total Unit Net Benefit (Cost)	$ 8.45	$ 6.76	$ 5.16	$ 3.42
Net Benefit (Cost) : Absolute value	$ 241,062,776	$ 149,826,182	$ 91,634,166	$ 48,165,300

Notes

1 Indirect economic benefits to RI from the Proposal Case


Annual cost of PPA above- or below- market by year
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$-
$(10,000,000)
$(20,000,000)
$(30,000,000)
$(40,000,000)
2018 $
2021
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
Discount Rate = 1.00%
Discount Rate = 3.00%
Discount Rate = 7.00%
Discount Rate = 4.89%

PUC 3-12

Request:

Please provide the value of the total and annual carbon emissions reductions from the project National Grid believes would be attributable to Rhode Island.

Response:

As indicated by an e-mail message sent on behalf of the Commission, dated April 5, 2019, this question has been withdrawn.

PUC 3-13

Request:

Please explain why marginal abatement cost is appropriate for calculating the benefits of greenhouse gas emissions reductions.

Response:

Please refer to the Company's response to Data Request PUC 3-14(d).

PUC 3-14

Request:

Referencing Bates page 301 of the filing,

a. Is the Avoided Energy Supply Components study (AESC 2018) the source of the marginal cost of greenhouse gas emissions abatement?

b. If so, please provide the technology identified as the marginal abatement technology for greenhouse gas emissions reductions.

c. Please also provide any regional marginal abatement technologies and the associated marginal abatement costs.

d. Please explain whether and why National Grid believes employing a marginal technology or a technology that is more expensive than the marginal technology creates benefits.

Response:

a. Yes. As cited on Bates page 301 of the filing, the Avoided Energy Supply Components in New England: 2018 Report, by Synapse Energy Economics (AESC 2018: June 2018 release), was the source of the marginal cost of greenhouse gas emissions abatement.

b. AESC 2018: June 2018 release, at 13, based on global marginal abatement costs, established a total environmental cost of $100 per short ton of CO2-eq emissions. This reflects the best available cost estimates for large-scale carbon capture and sequestration (CCS) (AESC June 2018 release, at 13).

c. AESC 2018: June 2018 release, at 13, based on New England marginal abatement costs, also established a total environmental cost of $174 per short ton of CO2-eq emissions, based on a projection of future costs of offshore wind energy.

d. On Bates page 301 of the filing, TCR describes how the benefits of CO2 reductions resulting from the proposal were calculated using the marginal abatement cost of carbon from AESC 2018: June 2018. AESC 2018: June 2018, at 140, includes the following explanation of how it concluded that the marginal abatement cost method should be used to estimate the value, or benefits, of damages avoided by GHG emissions reductions:

> There are two leading methods for estimating environmental costs: based on damage costs or based on marginal abatement costs. (In the idealized market of textbook economics, the two would coincide; in the real world, they are not necessarily identical.)
>
> Damage costs, if available and reliable, would be preferable, since they are a direct measure of the environmental impacts in question. Unfortunately, there are serious uncertainties surrounding climate damage estimates, based on both the theoretical frameworks for extreme risks and discounting of future impacts, and on the intrinsic problems of forecasting impacts at temperatures outside the range of historical experience.
>
> The social cost of carbon (SCC) estimates produced by the Obama administration's interagency task force in 2013 are a well-known example of damage cost estimates, averaging results from three climate economics models. All three models, however, minimize or ignore risks of extreme events, and rely on traditional, somewhat dated estimates of future damages. A review by the National Academy of Sciences (2017) found many problems in these models and called for development of a new approach to SCC estimates. A meta-analysis of SCC estimates, focusing on the incorporation of extreme risk, found that the SCC should be at least $125 per metric ton of CO2 (2014).
>
> In view of the many uncertainties in climate damage cost estimates, we conclude (as did AESC 2013 and 2015) that the marginal abatement cost method should be used instead. This method asserts that the value of damages avoided, at the margin, must be at least as great as the cost of the most expensive abatement technology used in a comprehensive strategy for emission reduction.

Thus, National Grid, and its consultant TCR, accepted the conclusion from AESC 2018: June 2018 that the marginal abatement cost for CO2 emissions could be used to estimate the associated benefits.

Given the recent regional offshore wind energy generation development, and as the offshore wind energy generation industry becomes more experienced, the marginal abatement technology for climate mitigation may vary from one study to the next, and thus the estimated avoided cost of carbon emissions may be adjusted accordingly.

PUC 3-15

Request:

Please explain how ISO New England's 2018 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report) was used in the energy market modeling, and if energy and/or peak load forecasts were used, which forecasts (e.g., 50/50, 90/10).

Response:

TCR uses the ISO New England Inc. (ISO-NE) 2018 Forecast Data File[1] (CELT Forecast) as well as the CELT Report to develop various input assumptions to the ENELYTIX energy market model.

Inputs from the CELT Forecast

i. **Annual Energy Projections:** TCR uses the available zonal forecasts for gross energy, energy from behind-the-meter photovoltaic (PV/BTMPV), and Energy Efficiency resources (EE/PDR), as reported in tab "2C Energy (GWh)." These inputs are used to develop energy forecasts that are net-of-EE and -PV generation.

ii. **Peak Load Projections:** TCR uses the 50/50 coincidental summer and winter peak load for gross peak, PV, and EE that are reported in tabs "2A Summer (MW)"and "2B Winter (MW)," respectively. These inputs are used to generate net-of-EE and -PV peak forecasts that TCR uses to develop hourly zonal load shapes.

   Please refer to the Company's response to Data Request PUC 3-16 for additional details on how TCR processes these inputs.

iii. **Installed Capacity Requirements (ICR):** TCR uses the 90/10 summer peak demand as reported in tab "2A Summer (MW)" to develop resource adequacy constraints for various capacity constrained zones used by the ENELYTIX capacity expansion module.

Inputs from CELT Report

i. **PV Projections:** TCR develops projections for non-FCM PV resources, using available capacity projections reported in tab "3.1.1 PV Forecast – Nameplate."

ii. **Generator List**: TCR uses the asset level information provided in tab "2.1 Generator List" to develop its internal database of available ISO-NE generation units.

[1] Available at: https://www.iso-ne.com/static-assets/documents/2018/09/forecast_data_2018.xlsx.

PUC 3-16

Request:

Please use a solid black line to plot a graph of the actual summer peak load for New England from 1998 to present. Please use and explain any adjustments National Grid or its consultant makes that are relevant and analogous to inputs of used to create the model results in the filing (e.g., weather normalization, net of behind-the-meter photovoltaic generation, etc.). On the same graph, please plot the analogous ISO New England CELT Report summer peak forecast for each CELT Report using a different color line for the forecast in each CELT Report. Please provide a table with the data depicted in the graph.

Response:

As indicated by an e-mail message sent on behalf of the Commission, dated April 5, 2019, this question has been withdrawn, and replaced with Data Request PUC 5-6.

PUC 3-17

Request:

Please provide the same information as in 3-12, but for winter peak load.

Response:

As indicated by an e-mail message sent on behalf of the Commission, dated April 5, 2019, this question has been withdrawn, and replaced with Data Request PUC 5-7.

PUC 3-18

Request:

Please provide the same information as 3-12, but for energy use.

Response:

As indicated by an e-mail message sent on behalf of the Commission, dated April 5, 2019, this question has been withdrawn, and replaced with Data Request PUC 5-8.

PUC 3-19

Request:

Please provide the annual average growth rate of the following model inputs:

a. Summer Demand in MW and percentage,

b. Winter Demand in MW and percentage,

c. Energy in MWH and percentage.

Response:

Please refer to Attachment PUC 3-19.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

Annual and average growth rates

Parameter	Unit	Value	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Energy	**GWh**		**146,009**	**147,538**	**149,100**	**150,485**	**151,766**	**153,072**	**154,364**	**155,767**	**157,182**	**158,610**	**160,051**	**161,506**	**162,973**
Annual Growth Rat	%			1.0%	1.1%	0.9%	0.9%	0.9%	0.8%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
Annual Growth	GWh			1,529	1,562	1,385	1,281	1,306	1,292	1,403	1,415	1,428	1,441	1,454	1,468
Average Annual Gr	%	0.914%													
Average Annual Gr	GWh	1,485													
Net Energy	**GWh**		**118,949**	**117,870**	**117,038**	**116,249**	**115,594**	**115,195**	**114,980**	**115,081**	**115,108**	**114,716**	**114,418**	**114,234**	**114,132**
Annual Growth Rat	%			-0.9%	-0.7%	-0.7%	-0.6%	-0.3%	-0.2%	0.1%	0.0%	-0.3%	-0.3%	-0.2%	-0.1%
Annual Growth	GWh			(1,079)	(832)	(790)	(655)	(399)	(215)	101	27	(392)	(299)	(183)	(102)
Average Annual Gr	%	-0.136%													
Average Annual Gr	GWh	(159)													
Gross Summer Peak	**MW**		**29,744**	**29,994**	**30,245**	**30,486**	**30,721**	**30,957**	**31,192**	**31,437**	**31,684**	**31,934**	**32,185**	**32,438**	**32,693**
Annual Growth Rat	%			0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Annual Growth	MW			250	251	241	235	236	235	245	247	249	251	253	255
Average Annual Gr	%	0.789%													
Average Annual Gr	MW	257													
Net Summer Peak	**MW**		**25,136**	**25,021**	**24,941**	**24,889**	**24,864**	**24,874**	**24,912**	**24,942**	**25,084**	**25,061**	**25,054**	**24,999**	**25,096**
Annual Growth Rat	%			-0.5%	-0.3%	-0.2%	-0.1%	0.0%	0.2%	0.1%	0.6%	-0.1%	0.0%	-0.2%	0.4%
Annual Growth	MW			(115)	(80)	(52)	(25)	10	38	30	142	(23)	(7)	(54)	97
Average Annual Gr	%	0.104%													
Average Annual Gr	MW	26													
Gross Winter Peak	**MW**		**23,322**	**23,450**	**23,581**	**23,698**	**23,805**	**23,915**	**24,024**	**24,140**	**24,258**	**24,375**	**24,493**	**24,612**	**24,731**
Annual Growth Rat	%			0.5%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Annual Growth	MW			128	131	117	107	110	109	116	117	118	118	119	119
Average Annual Gr	%	0.487%													
Average Annual Gr	MW	120													
Net Winter Peak	**MW**		**19,809**	**19,641**	**19,505**	**19,379**	**19,271**	**19,191**	**19,134**	**19,098**	**19,144**	**19,072**	**19,016**	**18,928**	**18,956**
Annual Growth Rat	%			-0.8%	-0.7%	-0.6%	-0.6%	-0.4%	-0.3%	-0.2%	0.2%	-0.4%	-0.3%	-0.5%	0.2%
Annual Growth	MW			(168)	(136)	(126)	(108)	(80)	(57)	(36)	47	(72)	(56)	(89)	28
Average Annual Gr	%	-0.162%													
Average Annual Gr	MW	(32)													

Parameter	Unit	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gross Energy	**GWh**	**164,454**	**165,949**	**167,456**	**168,978**	**170,513**	**172,063**	**173,626**	**175,204**	**176,796**	**178,402**	**180,024**	**181,659**
Annual Growth Rat	%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
Annual Growth	GWh	1,481	1,494	1,508	1,522	1,535	1,549	1,563	1,578	1,592	1,606	1,621	1,636
Average Annual Gr	%												
Average Annual Gr	GWh												
Net Energy	**GWh**	**114,186**	**114,248**	**114,318**	**114,394**	**114,494**	**114,575**	**114,571**	**114,642**	**114,763**	**114,883**	**114,957**	**115,124**
Annual Growth Rat	%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Annual Growth	GWh	53	63	70	76	99	81	(3)	71	121	120	74	167
Average Annual Gr	%												
Average Annual Gr	GWh												
Gross Summer Peak	**MW**	**32,950**	**33,209**	**33,470**	**33,733**	**33,999**	**34,266**	**34,536**	**34,807**	**35,081**	**35,357**	**35,635**	**35,915**
Annual Growth Rat	%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Annual Growth	MW	257	259	261	263	265	267	269	272	274	276	278	280
Average Annual Gr	%												
Average Annual Gr	MW												
Net Summer Peak	**MW**	**25,156**	**25,215**	**25,204**	**25,331**	**25,393**	**25,448**	**25,414**	**25,534**	**25,594**	**25,653**	**25,630**	**25,768**
Annual Growth Rat	%	0.2%	0.2%	0.0%	0.5%	0.2%	0.2%	-0.1%	0.5%	0.2%	0.2%	-0.1%	0.5%
Annual Growth	MW	60	59	(11)	127	61	55	(34)	120	60	59	(23)	138
Average Annual Gr	%												
Average Annual Gr	MW												
Gross Winter Peak	**MW**	**24,851**	**24,972**	**25,093**	**25,214**	**25,337**	**25,460**	**25,583**	**25,707**	**25,832**	**25,957**	**26,083**	**26,209**
Annual Growth Rat	%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Annual Growth	MW	120	120	121	122	122	123	123	124	125	125	126	126
Average Annual Gr	%												
Average Annual Gr	MW												
Net Winter Peak	**MW**	**18,958**	**18,961**	**18,914**	**18,973**	**18,983**	**18,990**	**18,933**	**18,991**	**19,006**	**19,020**	**18,975**	**19,049**
Annual Growth Rat	%	0.0%	0.0%	-0.2%	0.3%	0.1%	0.0%	-0.3%	0.3%	0.1%	0.1%	-0.2%	0.4%
Annual Growth	MW	2	3	(47)	58	10	8	(57)	58	14	14	(45)	74
Average Annual Gr	%												
Average Annual Gr	MW												

PUC 3-20

Request:

Please recalculate lines 1 through 12 of the Total Net Benefits table on Bates page 313 using demand and/or energy growth inputs (whichever are appropriate) that is, on average:

a. 1% lower than the growth rates used to generate the model results in the filing (i.e., 0.99*average growth used in the filed model results)

b. 10% lower than the growth rates used in the filing (i.e., 0.9*average growth rate)

c. 100% lower than the growth rates used in the filing (i.e., no load growth)

d. 1 % greater (i.e., 1.01*average growth rate)

e. 10% greater (i.e., 1.1*average growth rate)

f. 100% greater (i.e., 2*average growth rate)

- Please note that the parenthetical comments above assume the growth rate used to produce the model results in the filing were greater than zero. If the growth rate used was negative, the first three parenthetical comments must be switched with the last three.
- Please provide these results in a table in which the rows are lines 1 through 12 of he Total Net Benefits table on Bates page 313, the first column is the model results as filed and shown on Bates page 313, and the remaining columns are the responses to parts a through f.

Response:

As indicated by an e-mail message sent on behalf of the Commission, dated April 5, 2019, this question has been withdrawn, and replaced with Data Request PUC 5-9.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

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PUC 3-21

Request:

Please confirm whether or not National Grid or its consultant conducted multiple model runs representing a range of energy market and or economic conditions, assumptions, and inputs. If multiple model runs were not conducted, please explain why. Please respond separately for the energy market and economic analysis.

Response:

In evaluating the project, National Grid did not ask TCR to conduct multiple model runs representing a range of energy market and/or economic conditions, assumptions, and inputs.

The base case, and each proposal case, requires values for hundreds of input assumptions that can be grouped into about 10 major categories. TCR has documented the source of each of the assumptions, with the majority of them drawn from public sources. The goal was to develop reasonable, expected values for each assumption in order to develop a reasonable Base Case and reasonable Proposal Cases. The development and vetting of these input assumptions was comprehensive and took considerable time. In the Section 83D and Section 83C processes, TCR worked with experts from the EDCs, the Massachusetts Department of Energy Resources (MA DOER), and an Independent Evaluator in Massachusetts. Also, for this Docket, consultants for the Rhode Island Office of Energy Resources were able to provide an additional review of these assumptions and inputs.

The parties involved in these evaluation processes have recognized that there is perpetual uncertainty associated with the various projections used to establish the base case and proposal cases, and these are not meant to be definitive forecasts of or plans for the New England electricity markets. However, consistent with the approach taken in past studies, National Grid and its consultant focused on establishing inputs and assumptions which would be considered the most appropriate and reasonable given the latest and best available data from independent sources.

Please note that in its forthcoming response to Data Request PUC 5-7 (expected on or before April 26, 2019), National Grid will submit a sensitivity analysis model run.

PUC 3-22

Request:

Please provide the inputs and results of any sensitivity analyses conducted on any of the energy market and economic benefits results. If a sensitivity analysis was not conducted, please explain why. Please respond separately for the energy market and economic analysis.

Response:

Please refer to the Company's response to Data Request PUC 3-21.

PUC 3-23

Request:

If multiple models runs and/or sensitivity analyses were conducted for the energy market and economic analysis, please provide tables that present all model inputs that varied between each model run. Please make the rows of the table model inputs and the columns individual model runs. Please order the model runs in the order they were actually conducted, if that information was preserved. Please also indicate which model run(s) were used to generate the results presented in National Grid's filing. Please also include and indicate instances of model runs for which the model program crashed and did not complete the computational analysis if that information was preserved.

Response:

No additional runs or sensitivity analyses were conducted. Please refer to the Company's response to Data Request PUC 3-21.

PUC 3-24

Request:

Please explain if multiple model runs were averaged together to create the energy market and economic analysis results presented in National Grid's filing, and include any weighting that was used. If any of the model runs described above were excluded from the results presented in National Grid's filing, please explain why each was excluded.

Response:

Multiple model runs were not averaged to create the energy market and economic analysis results presented in the Company's filing. Please refer to the Company's response to Data Request PUC 3-21.

Prepared by or under the supervision of:
Timothy J. Brennan and Corinne M. DiDomenico

PUC 3-25

Request:

For all of the model runs described above that reached computation completion, whether or not they were included in National Grid's or its consultant's results presented in the filing, please provide a table in which the rows are lines 1 through 12 of he Total Net Benefits table on Bates page 313, the first column is the model results as filed and shown on Bates page 313, and the remaining columns are all of the model runs. Please order the columns in the order they were conducted, if that information was preserved.

Response:

No additional model runs or sensitivity analyses were conducted. Please refer to the Company's response to Data Requests PUC 3-21.

PUC 3-26

Request:

Please provide any runtime logs, lab books, or any other human- or computer-generated records of the modeling efforts associated with the energy market and economic analysis model runs for this filing.

Response:

Please refer to Attachment PUC 3-26 for a record of man-hours and machine time associated with TCR's modeling and analysis efforts for the development of the input assumptions and the ENELYTIX energy market models.

Record of Time

Staff	Man Hours
A. Rudkevich	38
H.He	200
N. Kumthekar	332
R. Hornby	189
S. Englander	20
X. Li	256
Total	**1,035**

Enelytix Run time	PSO Run Time (Hours)	Virtual Machine Run Time (Hours)
Base Case Capex Model	0.90	0.93
Base Case E&AS Model	1,181.29	1,266.23
Proposal Case Capex Model	0.93	0.93
Proposal Case E&AS Model	1,184.76	1,220.95
Total	**2,367.88**	**2,489.04**

PUC 3-27

Request:

Please provide any existing relevant comparisons of the energy market modeling methodology employed by National Grid or its consultant for this filing versus actual market outcomes. Please include any previous uses of the energy market methodology to analyze PPA proposals that were reviewed by a New England PUC. For each of those PPA proposal reviews, please provide the energy market costs and/or benefits projection, and for projects that were approved, please provide both the actual market and resource outcomes, if known. Please note that this last request recognizes that the actual performance of the resource may not be known, but actual market prices are public information.

Response:

Please see Attachments PUC 3-27-1 and PUC 3-27-2 Page 223/283, which provide benchmarking results of ENELYTIX ISO New England models against actual market outcomes. The ENELYTIX market modeling platform was developed by Newton Energy Group and was used by TCR to undertake the market modeling and analysis for Revolution Wind.

Almost identical energy market modeling and evaluation methods were employed by the Massachusetts Evaluation Teams to analyze more than 70 PPA proposals, and to consider portfolios, within the Massachusetts Sections 83C and 83D RFP processes.[1] These methods remain under review by the Massachusetts Department of Public Utilities in pending dockets. TCR supported the Evaluation Teams in these processes, which included the Massachusetts electric distribution companies, the Massachusetts Department of Energy Resources (DOER), and an Independent Evaluator. Public versions of TCR's quantitative evaluation reports for the Sections 83C and 83D solicitations were submitted in dockets D.P.U. 18-64/65/66 and D.P.U. 18-76/77/78.[2] However, energy market costs and/or benefit projections for these proposals were redacted and only filed confidentially, and thus are not publicly available.

The first year of the ENELYTIX projections used in the Sections 83C and 83D processes and to analyze Revolution Wind, is 2020 or later. Thus, no actual market prices for energy or RECs are available to compare to the ENELYTIX projections, as of yet.

[1] For more information, please see: https://macleanenergy.com/83c/ and https://macleanenergy.com/83d/.

[2] The dockets are available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9636764 and https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9676528.

ENELYTIX®
powered by PSO

ISO New England Model

Benchmarking Results

August 2018

Newton Energy Group LLC
75 Park Plaza, Fourth Floor, Boston MA 02116

This document summarizes the results of benchmarking ENELYTIX Model for the ISO-NE Market Model Database (MMD) against historical market data.

Key input sources:
Time Period: January 1, 2017 through December 31, 2017
Model Footprint: ISO New England.
Representation of System Interchanges: Actual hourly interchange flows between ISO-NE and NYISO, Hydro Quebec and New Brunswick as reported by ISO-New England
Load Data: actual hourly load by zone per ISO-NE data
Internal transmission Interfaces: hourly limits per ISO-NE data
Generation outage data: calibrated to actual capacity on outage as reported by ISO-NE
Fuel prices: daily natural gas and fuel oil price indices obtained from S&P Global
Hydro and wind generation: calibrated to monthly data as reported and EIA and ISO New England
Generation, transmission and ancillary service data: Newton Energy Group MMD for ISO New England

Benchmarking metrics:
LMPs simulated by ENELYTIX benchmarked against Daily Around the Clock, On-Peak, Off-Peak and Day-ahead LMPs at the West Central Massachusetts (WCMA) Zone as published by ISO-NE.

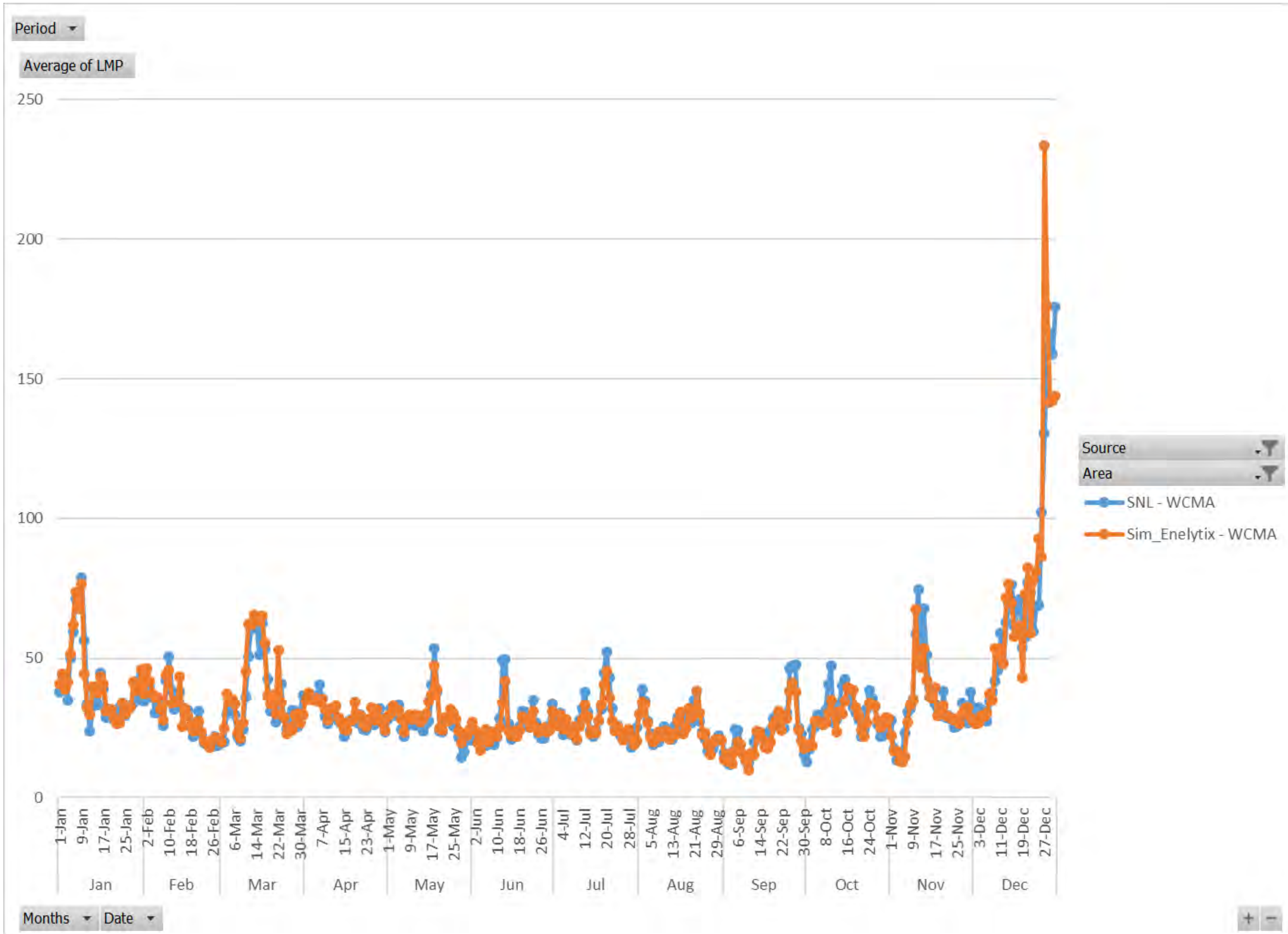

Figure 1. Around the Clock LMP Comparison

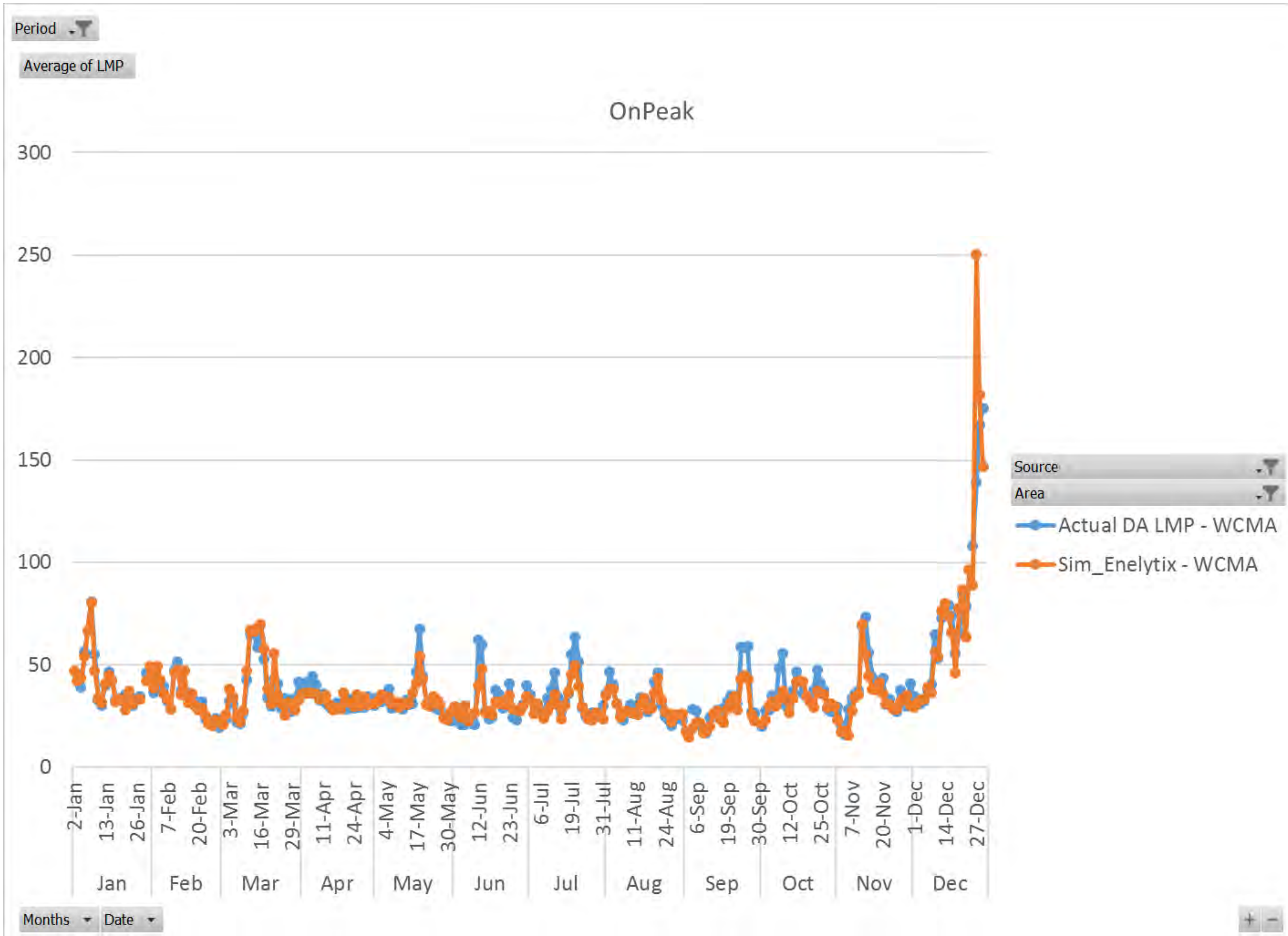

Figure 2. On-Peak LMP Comparison

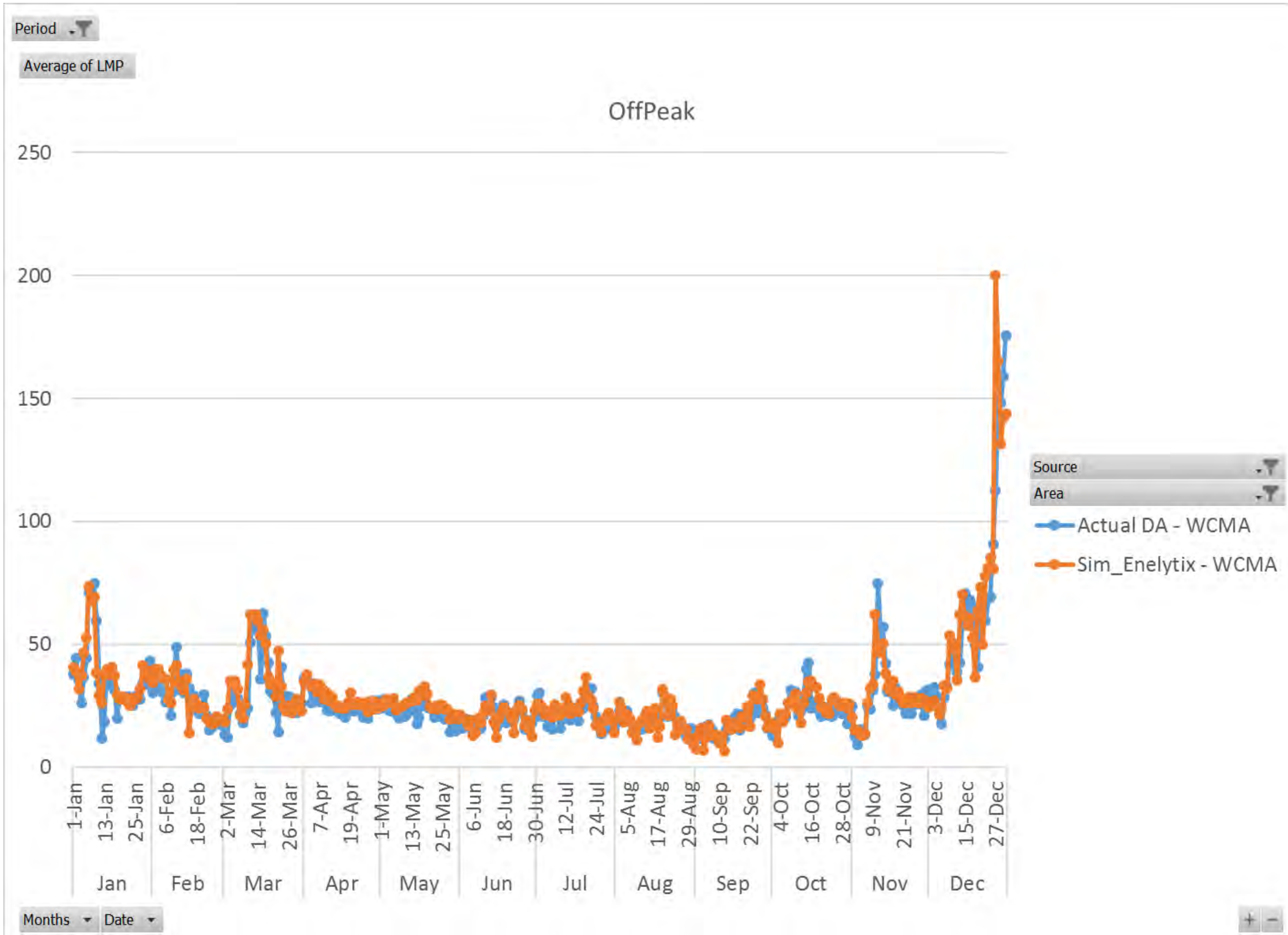

Figure 3. Off-Peak LMP Comparison

Avoided Energy Supply Costs in New England: 2015 Report

Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group

March 27, 2015

Revised April 3, 2015

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LIST OF ACRONYMS

AEO	Annual Energy Outlook
AGT	Algonquin Gas Transmission
AIM	Algonquin Incremental Market
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Bcf	Billion Cubic Feet
BDAT	Best Demonstrated Available Technology
CAGR	Compound Annual Growth Rate
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CECP	Clean Energy Climate Plan (Massachusetts)
CSAPR	Cross State Air Pollution Rule
DOER	Massachusetts Department of Energy Resources
DRIPE	Demand Reduction Induced Price Effects
EIA	Energy Information Administration
EMF	Energy Modeling Forum
EUR	Estimated Ultimate Recovery
FCAs	Forward Capacity Auctions
FCM	Forward Capacity Market
GWSA	Massachusetts Global Warming Solutions Act
IEA	International Energy Agency
IGCC	Integrated Gasification Combined-Cycle
IGTS	Iroquois Gas Transmission System
IPCC	Intergovernmental Panel on Climate Change
IRP	Interstate Reliability Project
LAER	Lowest Achievable Emissions Reductions
LDCs	Local Distribution Companies
LNG	Liquefied Natural Gas
LSEs	Load-Serving Entities
M&NP	Maritimes & Northeast Pipeline
MACT	Maximum Achievable Control Technology

MMcf	Million Cubic Feet
NAAQS	National Ambient Air Quality Standards
PDR	Passive Demand Resources
PNGTS	Portland Natural Gas Transmission System
RACT	Reasonably Available Control Technology
REC	Renewable Energy Certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SEDS	State Energy Data System
TCPL	TransCanada Pipelines
TETCO	Texas Eastern Transmission
TGP	Tennessee Gas Pipeline
VOM	Variable Operating and Maintenance Costs
WTI	West Texas Intermediate

Chapter 1: Executive Summary

This 2015 Avoided-Energy-Supply-Component Study ("AESC 2015," or "the Study") provides projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England. All reductions in use referred to in the Study are measured at the customer meter, unless noted otherwise.

AESC 2015 provides estimates of avoided costs for program administrators throughout New England to support their internal decision-making and regulatory filings for energy efficiency program cost-effectiveness analyses. The AESC 2015 project team understands that, ultimately, the relevant regulatory agencies in each state specify the categories of avoided costs that program administrators in their states are expected to use in their regulatory filings, and approve the values used for each category of avoided cost.

In order to determine the value of efficiency programs, AESC 2015 provides projections of avoided costs of electricity in each New England state for a hypothetical future, the "Base Case," in which no new energy efficiency programs are implemented in New England from 2016 onward. The Base Case avoided costs should not be interpreted as projections of, or proxies for, the market prices of natural gas, electricity, or other fuels in New England at any future point in time, for the following two reasons. First, the projections are for a hypothetical future without new energy efficiency measures and thus do not reflect the actual market conditions and prices likely to prevail in New England in an actual future with significant amounts of new efficiency measures. Second, the Study is providing projections of the avoided costs of energy in the long term. The actual market prices of energy at any future point in time will vary above and below their long-run avoided costs due to the various factors that affect short-term market prices.

AESC 2015 provides a fresh assessment of avoided electricity and natural gas costs from a new team using a model that simulates the operation of the New England wholesale energy and capacity markets in an iterative, integrated manner. On a 15 year levelized basis AESC 2015 estimates direct avoided retail electric costs on the order of 11 cents/kWh and direct avoided gas costs at utility city-gates in the order of $6.00 to $8.00/MMBtu depending on location and gas end-use.

The AESC 2015 estimates of direct avoided electricity and gas costs are similar to the corresponding AESC 2013 estimates. Certain AESC 2015 projections differ from those in AESC 2013 due to differences in market conditions that have occurred since AESC 2013 was completed, differences in certain assumptions regarding future market conditions and differences in analytical approaches. Key changes are:

- Increases in the quantity of shale gas production available at low marginal production costs, resulting in somewhat lower projections of avoided gas supply costs and lower avoided costs for electric energy;
- Assumed addition of a total of 1 Bcf/day of new pipeline capacity through November 2018;
- Earlier retirement of Brayton Point (2017 versus 2020) and higher costs for new fossil fueled generating capacity additions, leading to higher estimates of avoided costs for electric capacity;
- Higher Renewable Energy Credit (REC) prices due to the lower projection of wholesale energy market prices;
- Lower estimates of electricity demand reduction induced price effects ("DRIPE") from reductions in electricity use due to lower estimates of the size of those DRIPE effects and to shorter projections of the duration of those effects; and
- Lower estimates of natural gas and cross-fuel DRIPE from reductions in natural gas consumption due to lower estimates of gas supply elasticity and differences in analytical approach

The Study provides detailed projections of avoided costs by year for an initial 15-year period, 2016 through 2030, and extrapolates values for another 15 years, from 2031 through 2045.[1] All values are reported in 2015 dollars ("2015$") unless noted otherwise. For ease of reporting and comparison with AESC 2013, many results are expressed as levelized values over 15 years.[2] The AESC 2013 levelized results are calculated using the real discount rate of 2.43 percent, solely for illustrative purposes.[3]

1.1 Background to Study

AESC 2015 was sponsored by a group of electric utilities, gas utilities, and other efficiency program administrators (collectively, "program administrators" or "PAs"). The sponsors, along with non-utility parties and their consultants, formed an AESC 2015 Study Group to oversee the design and execution of the report.

The Study sponsors include: Cape Light Compact, Liberty Utilities, National Grid USA, New Hampshire Electric Co-op, Columbia Gas of Massachusetts, Eversource Energy (Connecticut Light and Power, NSTAR Electric & Gas Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas), Unitil (Fitchburg Gas and Electric Light Company, Unitil Energy Systems,

[1] Escalation rates for extrapolation are based on compound annual growth rates specific to the value stream and are noted throughout the report.

[2] 15-year levelization periods of 2014-2028 for AESC 2013 and 2016 to 2030 for AESC 2015. AESC 2013 used a real discount rate of 1.36 percent.

[3] The AESC 2015 real discount rate is a projection of the rate for a ten-year U.S. Treasury Bond developed from *An Update to the Budget and Economic Outlook: 2014 to 2024*, Congressional Budget Office, August 2014 and the Energy Information Administration (EIA) Annual Energy Outlook 2014 (AEO 2014), as detailed in Appendix E.

Inc., and Northern Utilities), United Illuminating Holding (United Illuminating, Berkshire Gas Company, Southern Connecticut Gas and Connecticut Natural Gas), Efficiency Maine, and the State of Vermont. The non-sponsoring parties represented in the Study Group include: Connecticut Department of Energy and Environmental Protection, Connecticut Energy Efficiency Board, Massachusetts Energy Efficiency Advisory Council, , Massachusetts Department of Public Utilities, Massachusetts Department of Energy Resources, Massachusetts Attorney General, Massachusetts Low-Income Energy Affordability Network (LEAN), Acadia Center, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers and Rhode Island Energy Efficiency and Resource Management Council.

The AESC 2015 Study Group specified the scope of services, selected the Tabors Caramanis Rudkevich ("TCR") project team, and monitored progress of the study. As instructed by the Study Group, the TCR team developed seven distinct forecast components which, are reported in Chapters 2 through 7 of this report (See Exhibit 1-1).

For each component, the TCR project team presented its methodologies, assumptions, and analytical results in draft deliverables for each of the subtasks specified by the Study Group. The TCR team reviewed each draft deliverable with the Study Group in conference calls. The relationships between the sections of this report, the forecast components, and the subtask deliverables are presented in Exhibit 1-1.

Exhibit 1-1. Relationship of Chapters to Forecast Components and Subtasks

Chapter/Appendix	Forecast Component	Subtasks
Chapter 2 – Avoided Natural Gas Costs	1	2A, 3A
Chapter 3 – Avoided Costs of Fuel Oil and Other Fuels	2, 5	2B, 3B, 2E, 3E
Chapter 4 – Embedded and Non-Embedded Environmental Costs	6	2F, 3F
Chapter 5 – Avoided Electricity Costs	3, 4	2C, 3C , 2D, 3D
Chapter 6 – Sensitivity Analyses	N/A	4B
Chapter 7 – Demand Reduction Induced Price Effects	7	2G, 3G
Appendix A – Usage Instructions	N/A	4C
Appendix G – Survey of Transmission and Distribution Capacity Values	N/A	4A
Appendix E – Common Financial Parameters	N/A	1

This report was prepared by a project team assembled and led by TCR. Rick Hornby managed the project. Dr. Benjamin Schlesinger and Dr. John Neri of Benjamin Schlesinger and Associates ("BSA") led the development of forecasts of natural gas and fuel oil supply costs as well as of gas demand reduction induced price suppression (gas DRIPE). Dr. Alex Rudkevich developed the forecasts of wholesale electric energy and capacity costs as well as of electricity DRIPE effects. Scott Englander of Longwood Energy Group led the analysis of Renewable Portfolio Standard ("RPS") requirements and compliance costs as well as of environmental costs avoided by reductions in energy use. Dr. Richard Tabors served as senior advisor.

1.2 Avoided Costs of Electricity

Initiatives that enable retail customers to reduce their peak electricity use ("demand") and/or their annual electricity use ("energy") have a number of key monetary and environmental benefits. Major categories of benefits include:

- Avoided costs due to reductions in quantities of resources required to meet electric demand and annual energy. Electric capacity costs are avoided due to a reduction in the annual quantity of electric capacity that load serving entities ("LSEs") will have to acquire from the Forward Capacity Market ("FCM") to ensure an adequate quantity of generation during hours of peak demand. Electric energy costs are avoided due to a reduction in the annual quantity of electric energy that LSEs will have to acquire. These avoided costs include a reduction in the cost of renewable energy incurred to comply with the applicable RPS.[4] Non-embedded environmental costs are avoided due to a reduction in the quantity of electric energy generated. (A non-embedded environmental cost is the cost of an environmental impact associated with the use of a product or service, such as electricity, that is not reflected in the price of that product.) AESC 2015 uses the long-term abatement cost of carbon dioxide emissions as a proxy for this value.
- Local transmission and distribution ("T&D") infrastructure costs are avoided due to delays in the timing and/or reductions in the size of new projects that have to be built, resulting from the reduction in electric energy that has to be delivered. AESC 2015 surveyed participating sponsors for recent values.
- Reductions in the quantities of capacity and energy that have to be acquired from wholesale energy and capacity markets may cause prices in those markets to decline relative to Base Case levels for a period of time. AESC 2015 refers to the reduction or mitigation of market prices due to reductions in demand for electric capacity and electric energy as "capacity DRIPE" and "energy DRIPE," respectively. In addition, reductions in annual retail electricity use will cause a reduction in gas consumption for electric generation, which is expected to have a price suppression effect on gas production and basis prices, which we refer to as electric own-fuel and cross-fuel DRIPE. (Reductions in annual retail gas use also have a price suppression effect on gas production and basis prices, which we refer to as gas fuel and cross-fuel DRIPE).

AESC 2015 developed estimates of the following major components of avoided electricity costs:

- **Avoided retail capacity.** Avoided retail capacity costs for the AESC 2015 Base Case consist of revenue from demand reductions bid into the FCM and the value of generating capacity avoided by demand reductions that are not bid into the FCM. Projected annual FCM prices are higher than in AESC 2013, for example 15 year levelized costs are approximately 77% higher. This

[4] Electric energy is measured in kilowatt hours (kWh) or megawatt hours (MWh); electricity capacity is measured in kilowatts (kW) or megawatts (MW).

increase is primarily due to earlier retirements of existing capacity (e.g. Brayton Point) and higher costs of new capacity.

- **Avoided retail energy.** This is the largest component of avoided electricity costs. It consists of the wholesale electric energy price increased by an assumed risk premium of 9%. Levelized annual avoided energy costs under the AESC 2015 Base Case are approximately 13% lower than those in AESC 2013, depending on the pricing zone. The levelized annual wholesale electric energy costs are lower primarily due to projections of lower natural gas prices and somewhat lower projected costs for compliance with anticipated federal regulations of carbon emissions.
- **Avoided RPS compliance costs.** Energy efficiency reduces the load subject to RPS obligations, avoiding the associated cost of compliance. The cost of RPS compliance is driven by the prices of renewable energy certificates (RECs), which are the principle means of compliance. AESC 2015 REC prices are approximately 40% higher than AESC 2013 because of the lower 2015 projections of wholesale energy prices.
- **Avoided non-embedded CO_2 costs.** This is the cost of controlling CO_2 emissions, to the extent that cost is not reflected in electricity market prices. The AESC 2015 projections are approximately the same as AESC 2013.
- **Electricity DRIPE.** This is the value of the reduction in capacity and energy market prices expected from reductions in electric energy use. AESC 2015 is projecting no electric capacity DRIPE and a smaller amount of electric energy DRIPE. The lower estimates are due to differences in projections of market conditions and differences in analytical approach. These are summarized in Section 1.4 and discussed in detail in Sections 6.10 and 7.2.

The relative magnitude of each component for the Summer On-Peak costing period is illustrated in Exhibit 1-2 for an efficiency measure with a 55-percent load factor implemented in the West Central Massachusetts zone (“WCMA”).

Exhibit 1-2. Illustration of Avoided Electricity Cost Components, AESC 2015 vs. AESC 2013 (WCMA Zone, Summer On-Peak, 15-Year Levelized Results, 2015$)

Illustration of Avoided Electricity Cost Components, AESC 2015 BASE vs. AESC 2013 (WCMA Zone, Summer On-Peak, 15 Year Levelized Results, 2015$)					
	AESC 2013 in 2013$	AESC 2013 in 2015$ [1]	AESC 2015 BASE	AESC 2015 BASE Relative to AESC 2013	
	cents/kWh	cents/kWh	cents/kWh	cents/kWh	% Difference
Avoided Retail Capacity Costs [2,3,4]	2.01	2.08	2.91	0.83	40%
Avoided Retail Energy Cost [5, 6, 7]	6.98	7.22	6.29	-0.93	-13%
Avoided Renewable Energy Credit [5, 6, 8]	0.66	0.69	0.96	0.27	39%
Capacity and Energy Subtotal	**9.65**	**9.99**	**10.15**	**0.17**	**2%**
CO_2 Non-Embedded	4.33	4.48	4.48	0.00	0%
Capacity DRIPE	0.69	0.71	0.00	-0.71	-100%
Intrastate Energy, Own Fuel and Cross-Fuel DRIPE	2.84	2.94	1.08	-1.86	-63%
DRIPE Subtotal	**3.53**	**3.65**	**1.08**	-2.57	-70%
Total	**17.51**	**18.12**	**15.71**	-2.41	-13%

Notes

1. AESC 2013 values levelized (2014-2028); escalated to 2015$ at		**1.035**
2. Assumes load factor of		**55%**
3. Avoided Cost of Capacity purchases ($/kW-year)	AESC 2013 (2013)	**$ 96.55**
	AESC 2015 (2015)	**$ 140.10**
4. Adjusted for 8% distribution losses and 17% reserve margin		
5. Retail Adjustment = Avoided Wholesale Cost * (1 + risk premium)		
6. Risk premium		**9%**
7. Avoided Energy Cost 2015$/MWh		**$ 57.68**
8. AESC 2015 REC (cents/kWh) pre-adjustment		**$ 0.88**

For this costing location and period, AESC 2015 is projecting total avoided costs from direct reductions in energy and capacity of 10 cents per kWh. This amount is approximately 2 percent higher than the corresponding AESC 2013 total.

The total of all components—i.e., the avoided cost of energy and capacity reductions (10 cents per kWh), plus energy and capacity DRIPE, plus non-embedded CO_2 costs—is 16 cents per kWh. This total is 13 percent lower than the corresponding AESC 2013 total.

1.2.1 Avoided Electric Capacity Costs

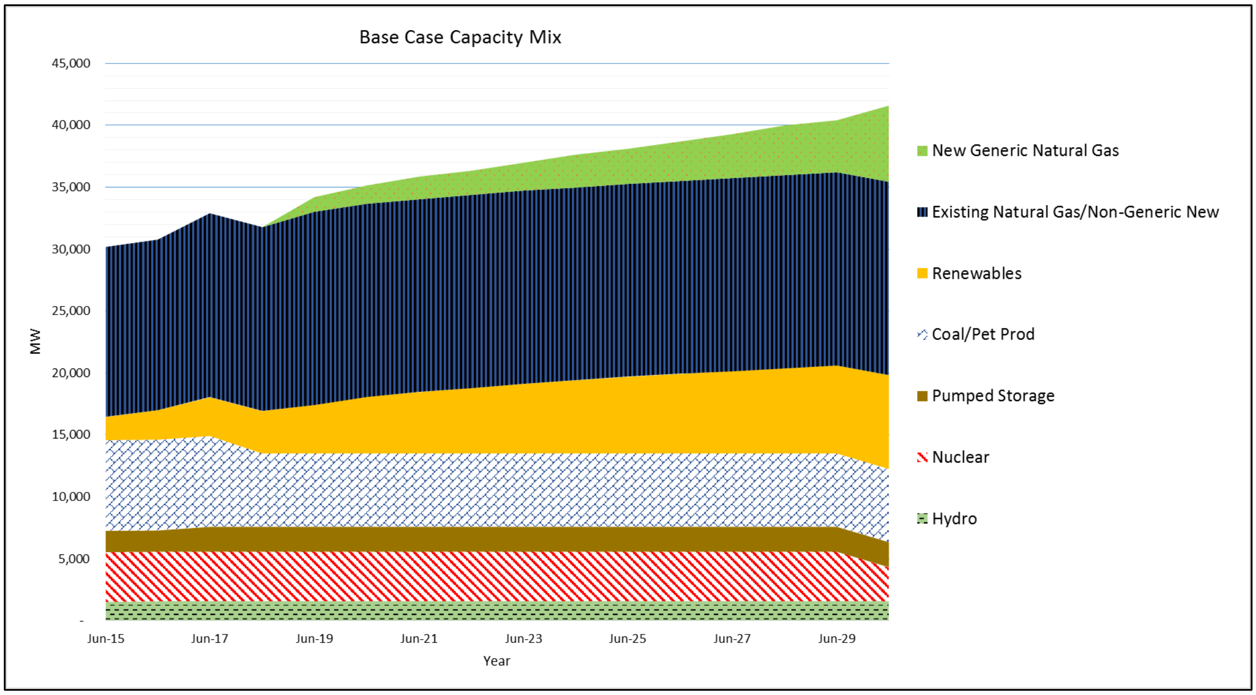
Avoided electric capacity costs are an estimate of the value of a load reduction by retail customers during hours of system peak demand.[5] The major input to this calculation is the wholesale forward capacity price to load (in dollars per kilowatt-month), which is set for a capacity year (June–May) roughly three years before the start of the capacity year. To develop an avoided cost at the meter, the wholesale electric capacity price is first increased by the reserve margin requirements forecasted for the year, then increased by eight percent to reflect ISO-New England's (ISO-NE's) estimate of distribution losses.

The major drivers of the avoided wholesale capacity price are system peak demand, capacity resources, and the detailed ISO-NE rules governing the auction. ISO-NE rules specify which resources are allowed to bid in the auction, how the resources' capacity values are computed, and what range of prices each resource category is allowed to bid. The load-resource balance is determined by load growth, retirements of existing capacity, addition of new capacity from resources to comply with RPS requirements, imports, exports, and new, non-RPS capacity additions.

As indicated in Exhibit 1-3, AESC 2013 projects that new capacity, other than RPS-related renewable resources, will have to be added starting in the 2018/2019 power year (The ISO-NE power year is June through May). This change is driven primarily by earlier projected retirements of certain existing fossil units.

[5] The benefit arises from two sources: the reduction of load at the system annual peak hour and the capacity credit attributed to energy-efficiency programs (called "passive demand response" in the ISO-NE forward capacity mechanism), measured as the average load reduction of the on-peak hours in high-load months or the hours with loads over 95 percent of forecast peak.

Exhibit 1-3. AESC 2015 Capacity Requirements vs. Resources (Base Case), MW



The AESC 2015 Base Case estimate of levelized capacity prices is approximately 40 percent higher than the estimate from AESC 2013 on a 15-year levelized basis... The higher values are primarily due to earlier retirements of existing generating units and more expensive capacity additions.

The actual amount of wholesale avoided electric capacity costs that a reduction in demand will avoid depends on the approach that the program administrator (PA) responsible for that reduction takes towards bidding it into the FCM. PAs will achieve the maximum avoided cost by bidding the entire anticipated kW reduction from measures in a given year into the FCA for that power year. PAs have to submit those bids when the FCA is held, However, the FCA for a given power year is held approximately three years in advance of the applicable power year. Some expected load reductions may not be bid into the first FCA for which the reduction would be effective, due to uncertainty about future program funding and energy savings.[6]

[6] PAs also avoid capacity costs from kW reductions that are not bid into FCAs, since those kW reductions lower actual demand, and ISO-NE eventually reflects those lower demands when setting the maximum demand to be met in future FCAs and the allocation of capacity requirements to load. However, the total amount of avoided capacity costs is lower because of the time lag—up to four years—between the year in which the kW reduction first causes a lower actual peak demand and the year in which ISO-NE translates that kW reduction into a reduction in the total demand for which capacity has to be acquired in an FCA. Since the load reduction in one year will affect the allocation of capacity responsibility in the next year, the PA's customers experience a one-year delay in realized savings that are not bid into the auctions at all.

1.2.2 Avoided Electric Energy Costs

Avoided electric energy costs at the customer meter consist of the wholesale electric energy price plus the REC cost plus a wholesale risk premium. Exhibit 1-4 presents the projected mix of generation underlying our projection of electric energy prices.

The AESC 2015 Base Case is projecting generation from natural gas to be the dominant source of electric energy over the study period. Renewable generation is projected to increase over time in compliance with RPS requirements. Generation from nuclear is projected to remain flat until year 2029 and then decline based on the assumption of Seabrook retiring in March 2030. Coal generation is projected to decline substantially by 2020 as unit retire.

Exhibit 1-4. AESC 2015 Base case Generation Mix (GWh)

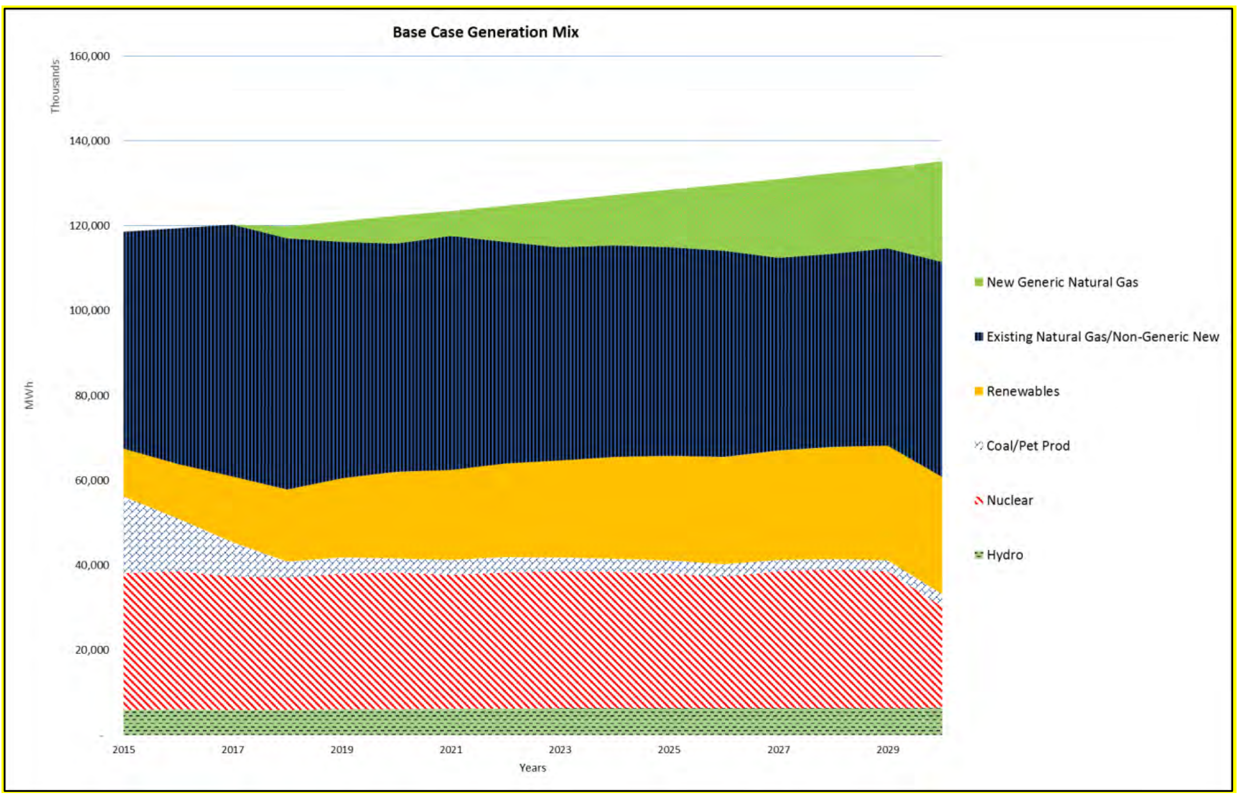


Exhibit 1-5 presents the AESC 2015 electric energy prices for the West Central Massachusetts zone for all hours compared to energy prices from AESC 2013. This WCMA price also represents the ISO-NE Control Area price, which is within this zone. On a 15 year levelized basis (2016-2030), the AESC 2015 annual all-hours price is $56.58/MWH (2015$), compared to the equivalent value of $61.95/MWh from AESC 2013, representing a reduction of 8.7 percent. The lower estimate for AESC 2015 is primarily due to a lower estimate of wholesale natural gas prices in New England and of CO_2 emission compliance costs.

Exhibit 1-5. AESC 2015 vs. AESC 2013 – All-Hours Prices for West-Central Massachusetts (2015$/kWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual All-Hours Energy
AESC 2015 (2016-2030)	$62.10	$56.82	$57.68	$45.04	$56.58
AESC 2013 (2014 - 2028)	$66.64	$58.78	$66.03	$53.33	$61.95
% Difference	-6.8%	-3.3%	-12.6%	-15.6%	-8.7%

Notes:
All prices expressed in 2015$ per MWh.
Discount Rate 1.36% for AESC 2013, 2.43% for AESC 2015

Exhibit 1-6 presents the resulting 15-year levelized avoided electric energy costs for AESC 2015 by zone, after adding in the relevant REC costs and wholesale risk premiums. This exhibit also provides the corresponding estimates from AESC 2013 by zone.

Exhibit 1-6. Avoided Electric Energy Costs, AESC 2015 vs. AESC 2013 (15-year levelized, 2015$)

Avoided Electric Energy Costs, AESC 2015 versus AESC 2013 (15 year levelized 2015$) Avoided Electric Energy Costs AESC 2015 and AESC 2013					
		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy
	AESC 2015	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Connecticut (statewide)	0.078	0.072	0.073	0.059
2	Massachusetts (statewide)	0.077	0.072	0.073	0.059
3	Maine (ME)	0.067	0.061	0.062	0.049
4	New Hampshire (NH)	0.076	0.071	0.071	0.058
5	Rhode Island (RI)	0.073	0.068	0.068	0.054
6	Vermont (VT)	0.067	0.062	0.063	0.049
	AESC 2013	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Connecticut (statewide)	0.079	0.070	0.078	0.064
2	Massachusetts (statewide)	0.079	0.070	0.078	0.064
3	Maine (ME)	0.066	0.060	0.064	0.054
4	New Hampshire (NH)	0.075	0.068	0.074	0.062
5	Rhode Island (RI)	0.066	0.060	0.064	0.053
6	Vermont (VT)	0.074	0.065	0.073	0.059

Exhibit 1-7 shows the change between AESC 2015 and AESC 2013 values, expressed as a percentage and in terms of 2015$ per kWh.

Exhibit 1-7. Avoided Electric Energy Costs for 2015: Change from AESC 2013 (expressed in 2015$/kWh and percentage values)

Avoided Electric Energy Costs, AESC 2015 versus AESC 2013 (15 year levelized 2015$) Avoided Electric Energy Costs : AESC 2015 Change from AESC 2013					
		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy
	Change from AESC 2013 ($/kWh)	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Connecticut (statewide)	(0.001)	0.002	(0.005)	(0.005)
2	Massachusetts (statewide)	(0.001)	0.001	(0.005)	(0.005)
3	Maine (ME)	0.001	0.002	(0.002)	(0.005)
4	New Hampshire (NH)	0.001	0.002	(0.003)	(0.004)
5	Rhode Island (RI)	0.007	0.008	0.004	0.002
6	Vermont (VT)	(0.007)	(0.003)	(0.011)	(0.010)
	Change from AESC 2013 (%)	**%**	**%**	**%**	**%**
1	Connecticut (statewide)	-1.4%	3.0%	-7.0%	-7.1%
2	Massachusetts (statewide)	-1.5%	1.6%	-6.8%	-8.4%
3	Maine (ME)	1.6%	3.0%	-3.2%	-9.6%
4	New Hampshire (NH)	1.1%	3.6%	-3.8%	-7.2%
5	Rhode Island (RI)	10.5%	12.5%	6.3%	3.2%
6	Vermont (VT)	-9.0%	-5.3%	-14.6%	-16.9%

1.2.3 Embedded and Non-Embedded Environmental Costs

Some environmental costs associated with electricity use are “embedded” in our estimates of avoided energy costs, and others are not. The costs that are embedded are incorporated in the pCA model used to generate wholesale energy prices for AESC 2015.

For AESC 2015, we anticipate that the “non-embedded carbon costs” will continue to be the dominant non-embedded environmental cost associated with marginal electricity generation in New England.

Based on our review of the most current research on marginal abatement and carbon capture and sequestration (“CCS”) costs, and our experience and judgment on the topic, we believe that it continues to be reasonable to use the AESC 2013 CO_2 marginal abatement cost of $100 per short ton.

1.3 Avoided Natural Gas Costs

Initiatives that enable retail customers to reduce their natural gas use also have a number of benefits. The benefits from those reductions include some or all of the following avoided costs:

- Avoided gas supply costs due to a reduction in the annual quantity of gas that has to be produced;
- Avoided pipeline costs due to a reduction in the quantity of gas that has to be delivered; and
- Avoided local distribution infrastructure costs due to delays in the timing and/or reductions in the size of new projects that have to be built resulting from the reduction in gas that has to be delivered.

Detailed results of our analysis are presented in Appendix C, Avoided Natural Gas Cost Results. A summary of results is presented below.

1.3.1 Wholesale Natural Gas Supply Costs

AESC 2015 assumes that the Marcellus/Utica shale will be the primary source of gas supply to New England. However, because a dominant liquid hub has yet to develop for that production area the forecast of wholesale natural gas commodity prices in New England is derived from projected gas prices at the Henry Hub. There are far more forecast and trading data available for Henry Hub than for the Marcellus/Utica area, a situation we expect will change over time.

The AESC 2015 Base Case estimate of Henry Hub prices is $ 5.18/MMBtu (2015$) on a 15-year levelized basis for the period 2016 to 2030. This is approximately 7 percent lower than the 15-year levelized price from the AESC 2013 Base Case for a similar time period.[7]

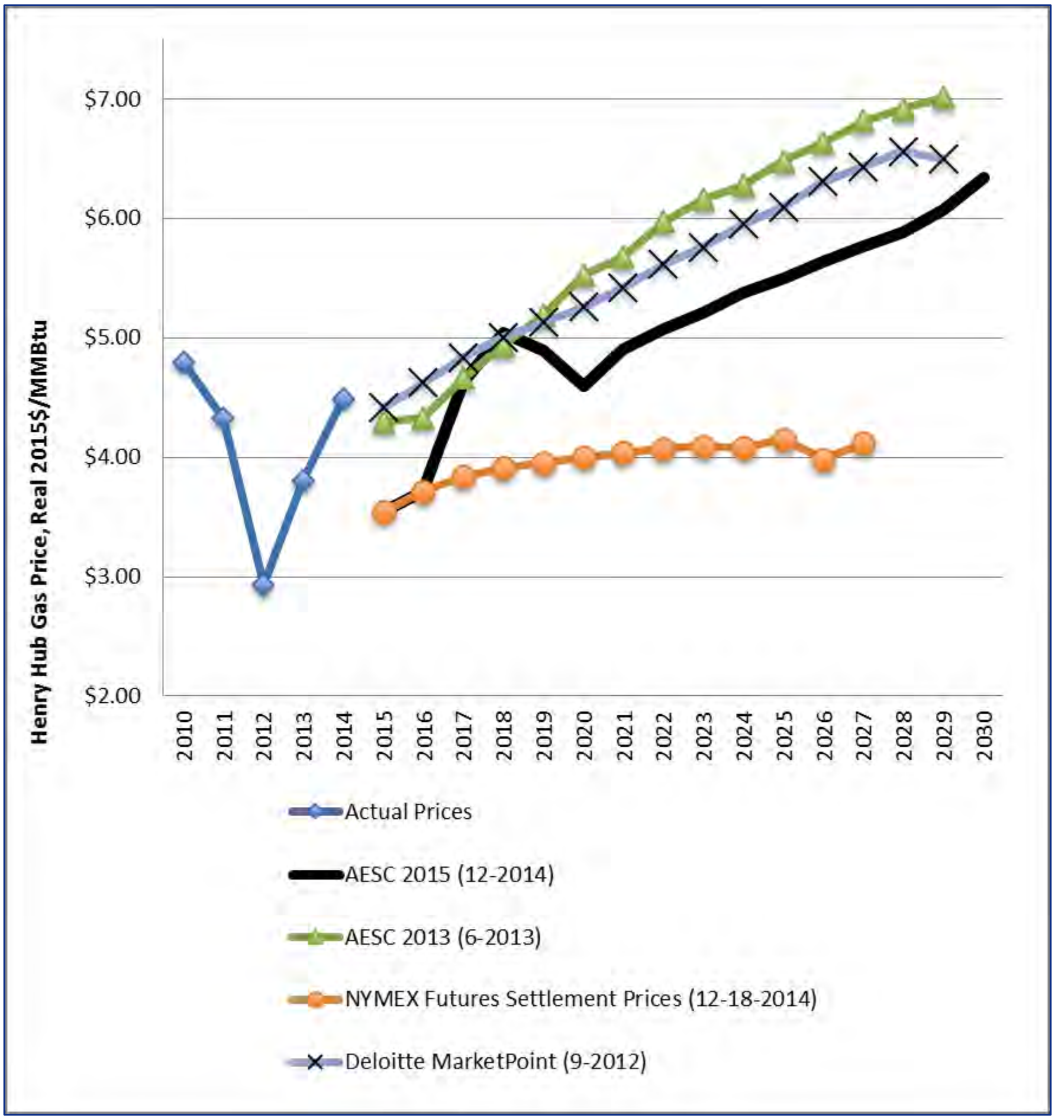
The AESC 2015 Base Case Henry Hub estimate is composed of NYMEX futures prices (as of December 18, 2014) through December 2016, and on a forecast derived from the Reference Case forecast from the Energy Information Administration's ("EIA's") Annual Energy Outlook ("AEO") 2014 for 2017 through 2030. The near-term forecast is based on NYMEX futures because they are an indication of the market's estimate of prices for the future months for which trading volumes are significant.[8] For the remaining period, the forecast is based on an AEO long-term forecast because it captures the market fundamentals that will drive those prices (i.e., demand, supply, competition among fuels) and because its underlying inputs and model algorithms are public.

Exhibit 1-8. Actual and Projected Henry Hub Prices (2015$/MMBtu) illustrates the difference between the AESC 2015 and AESC 2013 Henry Hub prices.

[7] The 15-year levelized (2014-2028) AESC 2013 Base Case in 2015$ is $5.56/ MMBtu, i.e.., 5.37/MMBtu (2013$) * 1.035).

[8] The NYMEX futures used to prepare prior AESC studies have proven to be higher than actual Henry Hub prices, indicating that price expectations of the gas industry are not always accurate.

Exhibit 1-8. Actual and Projected Henry Hub Prices (2015$/MMBtu)



This Exhibit indicates the downward trend in long-term forecasts of Henry Hub gas price forecasts since AESC 2013 was completed. Long-term gas price forecasts have been declining for several reasons. Actual gas prices have remained low. Expectations that gas supply will decline due to severe shale gas production decline rates have not materialized, nor have fears of significant production cost increases associated with the need to comply with tighter environmental regulations. Finally, and perhaps most importantly, drilling productivity has increased beyond expectations and drilling programs have become far more efficient, and time- and cost-effective.

1.3.2 Avoided Wholesale Gas Costs in New England

AESC 2015 developed a forecast of the avoided wholesale cost of gas in New England based on an analysis of the market fundamentals expected to drive that cost over the study period, using much the same general approach as the AESC 2013 Study. Specifically, the forecast of the avoided cost of gas supply begins with primary sources serving New England, and then forecasts avoided cost of gas delivery from primary sources to gas users in New England. The difference between the wholesale market price of gas at one delivery point and another delivery point is referred to as a gas price basis differential, or simply “basis.” AESC 2015 developed the avoided wholesale cost of gas in New England as the avoided cost at the Henry Hub plus the basis between the Henry Hub and New England.

In addition to developing a projection of the cost of gas from the Henry Hub and the Marcellus/Utica shale, the TCR team examined other key market fundamentals that will affect the avoided cost of gas in New England including projected demand for gas for electric generation and for retail end-uses, the projected quantity of imports of gas from Atlantic Canada and of LNG, and the projected level of pipeline capacity to deliver gas from the Marcellus/Utica shales into New England. (The projected demand for gas in New England for electric generation will be driven by numerous factors, including the long run projected price of fuel oil relative to the price of natural gas, and the level of financial penalties ISO-NE may impose on generating units which fail to meet their capacity performance obligations).

1.3.3 Avoided Natural Gas Costs by End Use

The avoided cost of gas at a retail customer’s meter has two components: (1) the avoided cost of gas delivered to the local distribution company (“LDC”), and (2) the avoided cost of delivering gas on the LDC system (the “retail margin”). AESC 2015 presents these avoided gas costs without an avoided retail margin and with an avoided retail margin, as the ability to avoid the retail margin varies by LDC.

The AESC 2015 avoided cost estimates are summarized in Exhibit 1-9 and Exhibit 1-10. These exhibits also compare the AESC 2013 results to the corresponding values from AESC 2013. Vermont requested AESC 2015 to provide avoided costs for a different set of costing periods.

Exhibit 1-9. Comparison of Avoided Gas Costs by End-Use Assuming No Avoidable Retail Margin, AESC 2015 vs. AESC 2013 (15-year levelized, 2015$/MMBtu except where indicated as 2013$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (CT, MA, RI)								
AESC 2013 (2013$)	6.08	6.57	6.73	6.60	6.26	6.58	6.44	6.53
AESC 2013 (b)	6.29	6.80	6.97	6.83	6.48	6.81	6.66	6.76
AESC 2015	6.00	6.53	6.70	6.56	6.20	6.54	6.39	6.48
2013 to 2015 change	-5%	-4%	-4%	-4%	-4%	-4%	-4%	-4%
Northern New England (ME, NH)								
AESC 2013 (2013$)	6.03	7.53	8.02	7.62	6.58	7.54	7.12	7.39
AESC 2013 (b)	6.24	7.80	8.30	7.89	6.82	7.81	7.37	7.65
AESC 2015	6.00	7.69	8.25	7.80	6.63	7.71	7.24	7.54
2013 to 2015 change	-4%	-1%	-1%	-1%	-3%	-1%	-2%	-1%

	Design day	**Peak Days**	**Remaining winter**	**Shoulder / summer**
Vermont				
AESC 2013 (2013$)	$ 389.03	$ 20.68	$ 8.68	$ 6.32
AESC 2013 (b)	$ 402.76	$ 21.41	$ 8.98	$ 6.54
AESC 2015	$ 523.08	$ 21.83	$ 7.51	$ 6.19
2013 to 2015 change	30%	2%	-16%	-5%

Factor to convert 2013$ to 2015$ 1.0353

Note: AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.
AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.

This set of AESC 2015 avoided natural gas cost estimates for Southern and Northern New England are generally lower than the AESC 2013 estimates, primarily due to the difference between the AESC 2015 projection of gas prices at Henry Hub and the AESC 2013 projection. The estimates for VT are also generally lower, except for the design day costs, which are higher due to a higher projection of Vermont Gas System (VGS) marginal transmission costs.

Exhibit 1-10. Comparison of Avoided Gas Costs by End-Use Assuming Some Avoidable Retail Margin, AESC 2015 vs. AESC 2013 (15-year levelized, 2015$/MMBtu except where indicated as 2013$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (CT, MA, RI)								
AESC 2013 (2013$)	6.67	7.17	8.30	8.12	6.88	7.74	7.44	7.80
AESC 2013 (b)	6.91	7.42	8.59	8.41	7.13	8.01	7.70	8.07
AESC 2015	6.62	7.89	8.32	8.13	6.81	7.68	7.37	7.35
2013 to 2015 change	-4%	6%	-3%	-3%	-4%	-4%	-4%	-9%
Northern New England (ME, NH)								
AESC 2013 (2013$)	6.53	8.04	9.35	8.91	7.04	8.40	7.86	8.17
AESC 2013 (b)	6.76	8.32	9.68	9.23	7.29	8.70	8.14	8.46
AESC 2015	6.52	8.86	9.64	9.15	7.11	8.61	8.01	6.88
2013 to 2015 change	-4%	6%	0%	-1%	-3%	-1%	-2%	-19%

Factor to convert 2013$ to 2015$ 1.0353

Note: AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.
AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.

This set of avoided natural gas cost estimates are also generally lower than the AESC 2013 estimates, again principally due to the lower projected gas price at Henry Hub. The exception is residential water heating, whose avoided margin was underestimated in AESC 2013.

1.4 Demand Reduction Induced Price Effects (DRIPE)

DRIPE refers to the reduction in wholesale market prices for energy and/or capacity expected from reductions in the quantities of energy and/or capacity required from those markets during a given period due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency received by all retail customers during a given period in the form of expected reductions in wholesale prices.

DRIPE effects are typically very small when expressed in terms of their impact on wholesale market prices, i.e., reductions of a fraction of a percent. However, DRIPE effects may be material when expressed in absolute dollar terms, e.g., a small reduction in wholesale electric energy price multiplied by the quantity of electric energy purchased for all consumers at the wholesale market price, or at prices / rates tied to the wholesale price.

The value of DRIPE is a function of (i) the projected size of the impact on market prices, (ii) the projected duration of that price effect, and (iii) the quantity of energy purchased at prices tied to the wholesale market price during the duration of the price effect.

AESC 2015 estimated three broad categories of DRIPE:

- **Electric efficiency direct DRIPE:** The value of reductions in retail electricity use resulting from reductions in wholesale electric energy and capacity prices from the operation of those wholesale markets.
- **Natural gas efficiency direct and cross-fuel DRIPE:** The value of reductions in retail gas use from reductions in wholesale gas supply prices and reductions in basis to New England. Gas efficiency cross-fuel DRIPE is the value of the reductions in those prices in terms of reducing the fuel cost of gas-fired electric generating units, and through them wholesale electric energy prices.
- **Electric efficiency fuel-related and cross-fuel DRIPE:** The value of reductions in retail electricity use from reductions in wholesale gas supply prices and reductions in basis to New England. The reductions in those prices reduces the fuel cost of gas-fired electric generating units, and through them wholesale electric energy prices. Electric efficiency cross-fuel DRIPE is the value of the reductions in the wholesale gas supply price to retail gas users.

Exhibit 1-11 provides a high level overview of the AESC 2015 estimates of electricity and natural gas DRIPE.

Exhibit 1-11. DRIPE Overview

Reduction in Retail Load	Cost Component Affected	DRIPE Category
Electricity	Electric Energy Prices	Own-price (energy DRIPE)
Natural Gas	Gas Production Cost	Own-price (gas Supply DRIPE)
	Gas Production Cost	Cross-fuel (gas to electric)
	Basis to New England	Cross-fuel (gas to electric)
Electricity	Gas Production Cost	Own-price (gas Supply DRIPE)
	Basis to New England	Own- price (basis DRIPE)
	Gas Production Cost	Cross - fuel (electric to gas)

The AESC 2015 electric efficiency direct DRIPE results are lower than the corresponding AESC 2013 DRIPE results because AESC 2015 is projecting electricity DRIPE to be smaller in size and shorter in duration. The differences between the two studies are due to differences in analytical approach and in projected market conditions.

The AESC 2015 natural gas efficiency direct and cross-fuel DRIPE results, and electric efficiency fuel-related and cross-fuel DRIPE results are lower than the corresponding AESC 2013 DRIPE results primarily because of a lower estimate of basis due to a different analytical approach.

1.4.1 Analytical Approach to Estimate Electricity DRIPE

AESC 2015 estimated the size and duration of electricity DRIPE in New England, both capacity and energy, using a differential approach based on direct simulations of projected market conditions and resulting projected market prices under several different cases. AESC 2015 used a BAU Case, described in Chapter 6, as the reference point against which it measured the size and duration of DRIPE effects under each of the other cases. The other cases are the BASE Case, described in Chapter 5, and state-specific DRIPE Cases for each New England state, described in Chapter 7. The different approach is the analytical approach most commonly used to estimate DRIPE. AESC 2013 estimated the size of DRIPE using regression analyses and estimated the duration of DRIPE based on qualitative estimates.

1.4.2 Size of Electricity DRIPE.

AESC 2015 is projecting a capacity price DRIPE effect of zero. In the short term ISO New England (ISO-NE) has already set capacity prices through the 2018 power year. In the long term, as discussed in Section 6.10, AESC 2015 models future ISO-NE auctions to avoid acquiring surplus capacity and presumes that the cost characteristics of the new gas CT and CC units that will be setting the capacity market price are essentially the same.

AESC 2015 is projecting smaller energy DRIPE effects than AESC 2013 over the period January 2015 through May 2018. AESC 2015 projects the energy market prices under the BAU case and each state-specific DRIPE case by simulating the formation of energy prices based on the energy supply curve and the ISO-NE unit commitment process. The formation of energy prices under those cases, and hence the size of the resulting energy DRIPE is largely driven by the AESC 2015 assumptions' regarding the supply curve and unit commitment process.

The supply curve dampens energy DRIPE because the section of the curve that sets energy prices on most days is essentially flat, as described in Section 6.10. The unit commitment process dampens energy DRIPE because ISO-NE makes its decisions regarding which units to commit to serving load based on its projection of load for 24 hours, not for just one hour, as described in Chapter 5. Because of those two factors, AESC 2015 did not find a simple linear relationship between the energy load in a given hour and the load in that hour. Instead, AESC 2015 has demonstrated that the relationship between energy prices and loads in a given hour, is affected by load throughout the day, fuel prices on the day and unit availability on the day.

There will be days on which actual conditions will differ from the ISO NE forecast conditions due to unanticipated market conditions, e.g., an unexpected outage, oversupply or unexpectedly high or low demand. It is not clear that energy DRIPE effects would occur under those types of unexpected market conditions, i.e., when the market did not operate exactly as planned ("perfect markets" or according to perfect foresight). Many factors can cause unexpected market conditions, and one would have to identify and analyze those factors in order to determine if load reductions from energy efficiency would have any effect on prices under those conditions. In other words, to estimate the energy DRIPE effect of efficiency reductions on a day when actual conditions are materially different from forecast conditions, one must know the specific cause of the difference. It is also important to note that energy efficiency is a long-term, passive demand resource. As such, its load reduction profile is very different from that of Active Demand Resources, which provide reductions only at the time of and only in response to unexpected market conditions.

1.4.3 Duration of Electricity DRIPE

AESC 2015 is projecting electricity DRIPE effects to be shorter in duration than AESC 2013, ending after two and a half years (June 2018) rather than eight years. The differences in estimates of duration are due to differences in projection of market conditions and in analytical approach. AESC 2015 projects that ISO-NE will begin adding gas-fired capacity in all zones starting in the 2018/19 power year, approximately three years earlier than ASESC 2013. Also, AESC 2015 developed its projections of capacity and energy DRIPE from 2018 onward directly using simulation modeling of the energy market.

1.5 Avoided Cost of Fuel Oil and Other Fuels

Some electric and gas efficiency programs enable retail customers to reduce their use of energy sources other than electricity or natural gas. The benefits associated with reducing the use of "other fuels"—such as fuel oil, propane, kerosene, biofuel, and wood—include avoided fuel supply costs. For petroleum-related fuels, the major driver of these avoided costs are forecast crude oil prices.

The avoided costs of fuel oil and other fuels are used primarily by administrators of electric energy efficiency programs. Detailed results are presented in Appendix D, Avoided Costs of Other Fuels.

Exhibit 1-12 summarizes the prices projected by AESC 2015 and AESC 2013 for fuel oil and other fuels.

Exhibit 1-12. Comparison of AESC 2015 and AESC 2013 Fuel Oil and Other Fuel Prices (15-year levelized, 2015$)

Sector	Residential						Commercial	
Fuel	No. 2 Distillate	Propane	Kerosene	BioFuel	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)
AESC 2015 Levelized Values (2015$/MMBtu); 2016-2030	$ 19.20	$ 18.35	$ 20.94	$ 18.68	$ 6.80	$ 7.74	$18.70	$16.47
AESC 2013 Levelized Values (2015$/MMBtu); 2014-2028	$ 28.89	$ 29.16	$ 31.73	$ 30.35	$ 10.47	$ 17.45	$ 27.78	$ 16.80
AESC 2015 vs AESC 2013, % higher (lower)	-33.5%	-37.1%	-34.0%	-38.5%	-35.0%	-55.6%	-32.7%	-1.9%

The projected AESC 2013 prices for these fuels are generally lower than those from AESC 2013, primarily due to a fundamentally lower forecast of underlying crude oil prices. On a 15-year levelized basis, the AESC 2015 values range from 32 percent to 55 percent lower than the AESC 2013 projections, except for residual.

Chapter 2: Avoided Natural Gas Costs

This Chapter presents the AESC 2015 projections of avoided natural gas costs to power plants and to retail gas customers in New England. It describes the major economic and technical assumptions underpinning the major component of those projections, i.e., the avoided costs of gas production, the avoided cost of delivering gas from production areas to wholesale buyers in New England, and the avoided costs of distributing gas to retail end-users.

2.1 Overview of New England Gas Market

In order to place our forecast of wholesale natural gas prices for New England in context we begin with an overview of demand for natural gas in New England by major consuming sector as well as the physical supply of gas to the region.

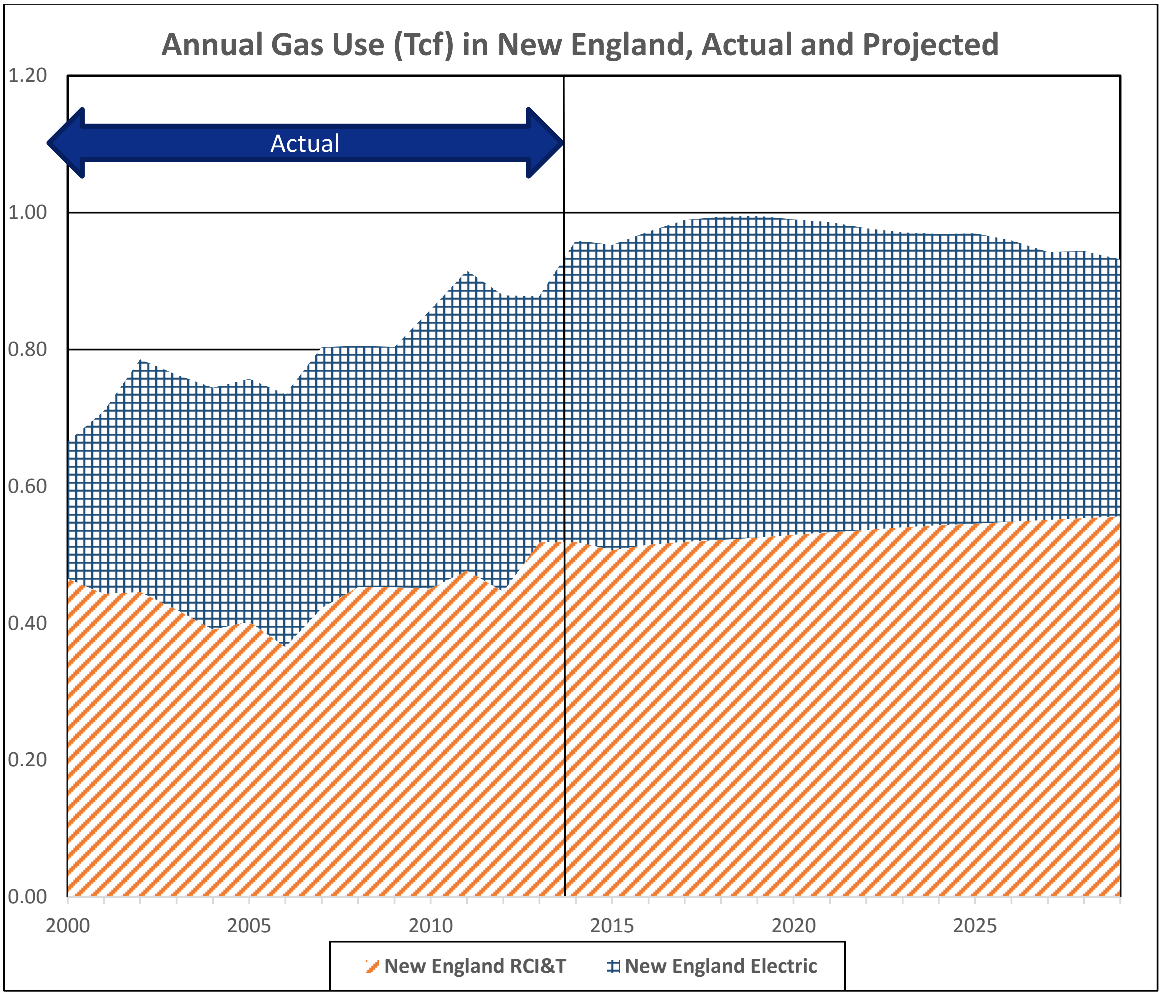
2.1.1 Demand for Gas in New England

Total gas use in New England is currently about 1 trillion cubic feet per year (EIA 2014). The market for that gas can be grouped into two distinct categories. The first category is natural gas purchased for direct use by, or on behalf of, very large end-users in the electric-generation, industrial, commercial, and institutional sectors. The second category is gas purchased by local distribution companies (LDCs) for re-sale to retail customers in the residential, commercial, and industrial (RC&I) sectors. The annual quantity of gas use in each category, actual and projected is presented in Exhibit 2-1.

The annual quantity of natural gas purchased for direct use by very large end-users, primarily for electric generation, has increased dramatically since the 1990s. That demand today accounts for roughly half of the annual gas consumption in New England. In its 2014 Annual Energy Outlook (AEO 2014), the Energy Information Administration (EIA) forecast annual gas use for electric generation in New England to remain relatively constant between 2014 and 2028 in most cases.[9]

[9] AEO 2014, Table: Energy Consumption by Sector and Source, New England, Reference case and High Oil & Gas Resource Case.

Exhibit 2-1. Actual and Projected Annual Gas Use in New England (Tcf)



The annual quantity of gas purchased by LDCs for resale to residential, commercial and industrial customers has been relatively stable since the 1990s. The AEO 2014 Reference Case projects gas use in those sectors to grow at about 0.39% per year between 2014 and 2028.[10] There is a strong interest in expanding retail use of gas in New England by extending existing distribution systems to provide consumers in under-served areas greater access to natural gas service. However, experience from other jurisdictions indicates that increasing retail gas use in this manner typically takes a number of years. For example, growth of retail natural gas use in Nova Scotia and New Brunswick has been gradual following

[10] The AEO 2014 High Resource Case projects gas use in those sectors to grow at 0.57% per year over that period.

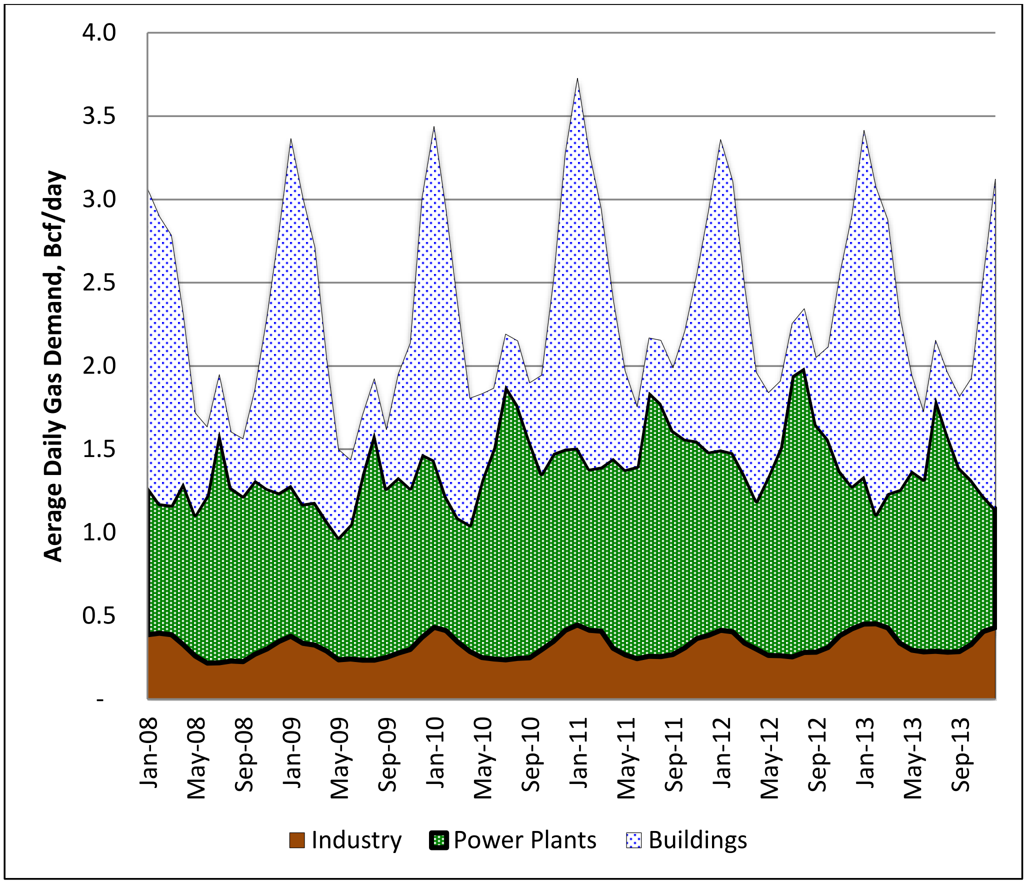
completion more than a decade ago of the large-scale M&NP; the same was the case in California following major expansions of gas pipeline capacity from Western Canada.[11]

The demand for wholesale gas in New England in all sectors varies substantially by season, and in some cases, from month by month within each season. The quantity of gas for direct use varies by month, with the greatest use occurring in summer months. In contrast, the greatest gas use by retail customers occurs in winter months since the dominant end-use is heating. As a result, LDCs have a much greater seasonal swing in gas load during the course of a year. For example, an LDC's gas load in January or February can be five times its load in July or August. Because of these large swings in gas load, LDCs acquire a portion of their winter requirements during the summer, store it in underground facilities outside of New England, and withdraw it during the winter when needed. In addition, LDCs use liquefied natural gas (LNG) and propane stored in New England to meet a portion of their peak requirements on the coldest days of the winter.

The variation in gas use by month in New England in 2008-2013 is illustrated in Exhibit 2-2.

[11] Source: Statistics Canada, California Energy Commission; pipelines refer to 0.55 Bcf/day M&NP (Canadian portion) completed in 1999 and 0.2 Bcf/day PG&E Line 401 expansion in 2002.

Exhibit 2-2. Monthly Gas Use in New England (January 2008 through December 2013)



Source: EIA.

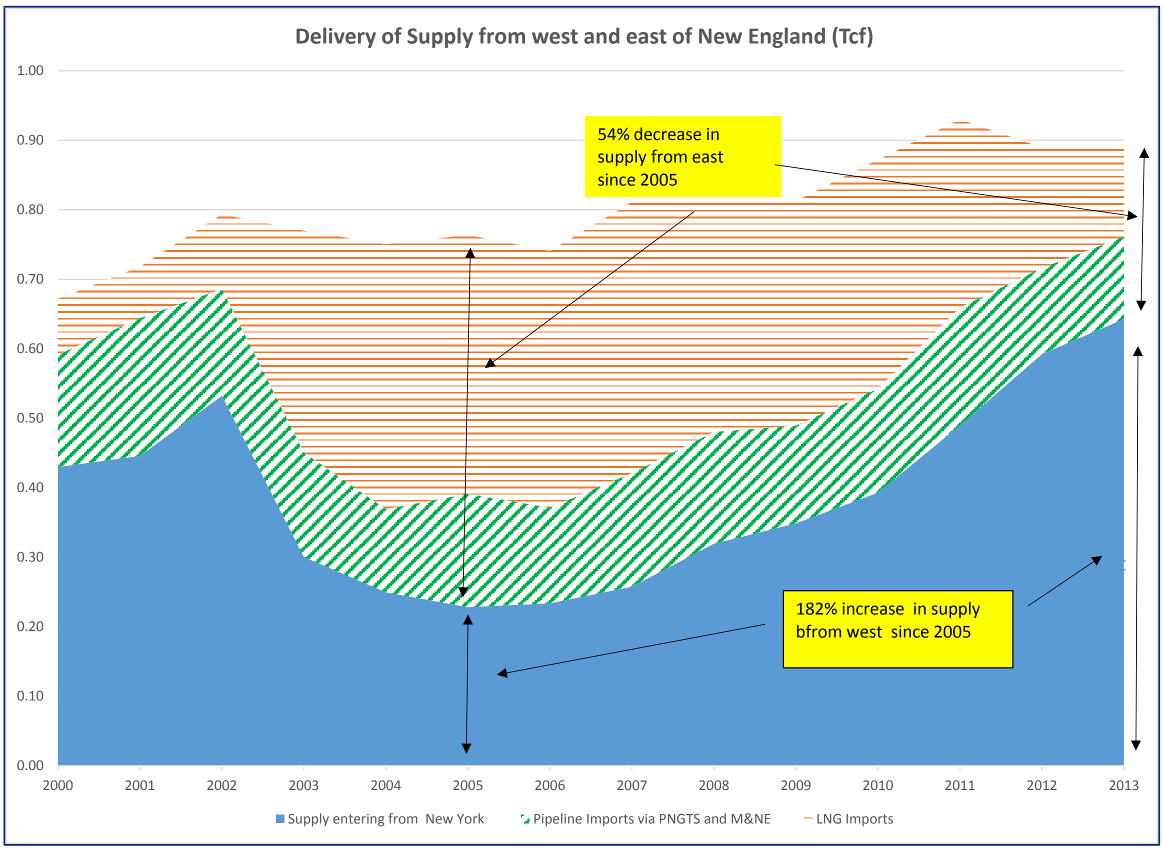
2.2 Supply of Wholesale Gas in New England

The natural gas used in New England is acquired from gas producing areas located outside New England and delivered to the region. Most of the gas consumed in New England is delivered by pipeline from producing areas in Appalachia, with smaller amounts from the U.S. Southwest, Western Canada, and Eastern Canada. Liquefied natural gas (LNG) is delivered by ship from LNG-exporting countries, principally Trinidad and Tobago in recent years.

Adequate delivery capacity from producing areas to New England, and within New England, is essential to ensure a firm supply of natural gas to, and within, the region. During the past two winters wholesale market prices spiked dramatically, to approximately $17/MMBtu in February 2012 and $25/MMBtu in February of 2013, and some gas-fired generating units were unable to operate due to inadequate gas supply. That experience highlights the need for additional delivery capacity within New England and, equally important, the need for additional delivery capacity to bring gas from producing areas west of New England, principally from the Marcellus/Utica fields, into New England in winter months.

That need for additional pipeline capacity to deliver gas from Marcellus/Utica to New England has been driven in part by the sharp decline in gas deliveries into eastern New England. Those gas deliveries are imports from Atlantic Canada and Quebec delivered into Maine, and LNG delivered into Massachusetts. Those imports have declined sharply, especially since 2011. As, indicated in Exhibit 2-3, the combined annual supply from those sources has declined over 50% since their peak in 2005. As we will discuss in 2.10, we do not expect supplies from those two sources to increase materially over the study period. In contrast, supply delivered from other producing areas into western points of the regional grid has increased over 180% since 2005.

Exhibit 2-3. Annual Gas Supply to New England



Source: TCR, from EIA data.

The following key features of the natural gas industry market structure, particularly the pipeline sector, help explain the lack of adequate delivery capacity to bring gas from producing areas west of New England in winter months.

- First, interstate pipelines, such as Algonquin Gas Transmission (AGT) and TGP which serve New England, are not allowed to sell gas; instead, they provide transportation and storage services to their customers ("shippers") under prescribed terms and conditions ("tariffs") under rate schedules approved by the FERC. Shippers acquire this capacity under long-term contracts of 10-20 years with the pipelines. Most pipelines serving the U.S. northeast, including New England, are fully subscribed, i.e., all of their capacity is spoken for (contracted) by shippers under firm transportation contracts guaranteeing shipment of gas up to the maximum amount in the contract, except for events of force majeure.

- Second, existing firm contract holders ("firm shippers") may release their capacity rights – much like sub-letting realty - in secondary markets in which firm capacity rights are acquired by other shippers. In this way, pipeline capacity rights are available in a flexible array of durations, some as short as a day or less (e.g., for power generation needs), and along various paths. But during times when gas demand is high, the firm shippers, many of whom are gas distribution utilities that must serve their retail customers, typically do not release their capacity.
- Third, FERC generally will not allow interstate pipelines to build new capacity unless they have lined up shippers who are prepared to enter long-term contracts for that new capacity. The major reason why there has been and continues to be, a shortage of pipeline capacity to deliver gas to power plants in New England, particularly in winter months, is the reluctance of those power plants to enter long-term contracts for firm capacity on those pipelines.

2.2.1 Pipelines delivering gas to, and within, New England

The physical pipeline system through which gas is delivered to New England is illustrated in Exhibit 2-4. Pipelines deliver gas directly to a number of electric generating units and very large customers, and indirectly through deliveries to LDCs which, in turn, distribute that gas to retail customers. A more extensive discussion of the New England gas industry and gas supply is published by the Northeast Gas Association (NGA 2013).

Exhibit 2-4. Natural Gas Pipelines Serving New England

Source: State of Connecticut, Joint Natural Gas Infrastructure Expansion Plan, 2014.

Deliveries into western New England

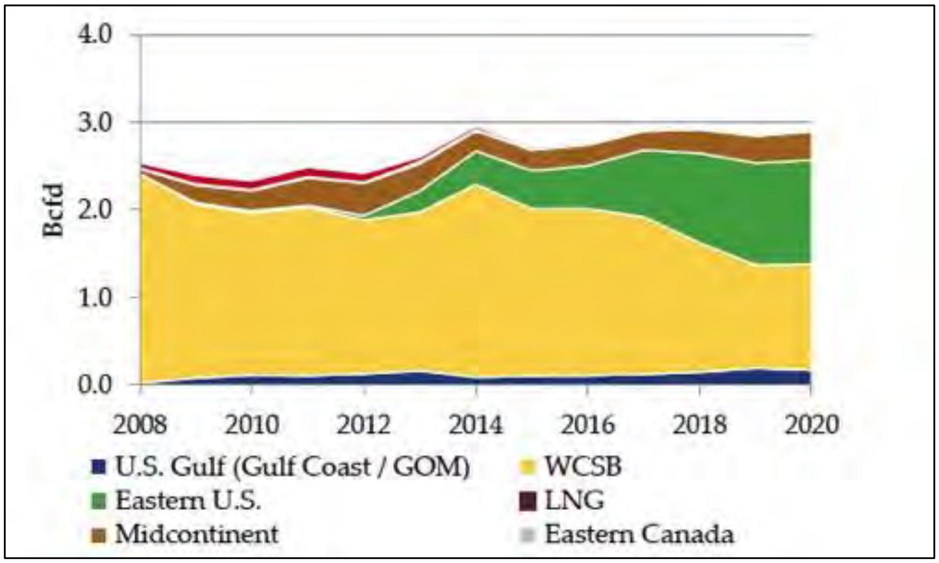
Two pipelines directly from the Marcellus/Utica shale region – Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (AGT, an effective extension of Spectra's Texas Eastern Transmission system, or "Tetco") – deliver the majority of gas consumed in New England. TGP delivers primarily into Massachusetts, New Hampshire and Maine while AGT delivers primarily into Connecticut, Rhode Island, and Massachusetts.

The Iroquois Gas Pipeline delivers gas into Connecticut, which it receives from TGP in New York State and from the TransCanada pipeline in Quebec, Canada.

Deliveries from TCPL. The Portland Natural Gas Transmission System (PNGTS) receives gas from the TransQuebec and Maritimes Pipeline (TQM), which is an extension within Quebec of the TransCanada Pipeline (TCPL). The point of receipt is at the international border at Pittsburg, New Hampshire. PNGTS also receives gas from New Brunswick, Canada, via the Maritimes and Northeast Pipeline (M&NP), which moves gas from the international border at Eastport, Maine to an interconnection in, Maine. PNGTS, M&NP and Granite State Pipeline all then connect Westbrook, Maine with Tennessee Gas Pipeline (TGP) at an interconnection in Haverhill, Mass. The segment of between Westbrook, ME and Haverhill, MA consists of shared facilities jointly owned and operated by PNGTS, M&P and Granite State Pipeline. Gas deliveries to Vermont continue to be entirely from Canada, via TCPL, at an interconnection with Vermont Gas at the international border in Highgate Springs, VT.

An increasingly substantial portion of gas flowing from TCPL into Northern New England via PNGTS, into Connecticut from the Iroquois Gas Pipeline, and into Vermont Gas emanates from the Marcellus/Utica shale region. As shown in Exhibit 2-5, gas supplies into Ontario from the Eastern U.S. gas are increasingly replacing supplies from the WCSB – 'Eastern U.S.' in the exhibit refers to the Marcellus/Utica shale region, which has become the marginal source of gas supply on TCPL's eastern section because of its low price and ample volumes.

Exhibit 2-5. Gas Supply Mix in Ontario



Source: Navigant 2014 Mid-Year Outlook, from Ontario Energy Board, 2014 Natural Gas Market Review, Navigant Consulting, Inc., December 2014, page 37.

EIA data on pipeline gas imports and exports substantiate the Ontario analysis. They show that Niagara has turned into an export point carrying increasing volumes of pipeline gas from the Marcellus/Utica region into Ontario, while diminishing volumes are entering Canada from the St. Clair, Michigan, interconnection that formerly carried WCSB gas back into Canada via the Great Lakes Transmission Pipeline, a part of TCPL.

Deliveries into Eastern New England

The Maritimes & Northeast Pipeline (M&NP) and Portland Natural Gas Transmission System (PNGTS) systems deliver gas into Maine, Massachusetts, and New Hampshire. Those pipelines ultimately deliver into the TGP system at the interconnection in Dracut, Massachusetts and into Algonquin via the Hubline project from Beverly to Weymouth, Massachusetts (see the potion of Algonquin located offshore northeastern Massachusetts in Exhibit 2-4). M&NP delivers gas from the Canaport LNG receiving/regasification import terminal in New Brunswick, Canada, and from offshore Nova Scotia. PNGTS receives gas from the TransQuebec & Maritimes Pipeline (TQM) in Quebec, Canada. As noted earlier, an increasingly substantial portion of gas flowing on PNGTS emanates from the Marcellus/Utica shale region as TQM receives all of its gas supplies from TCPL in Ontario.

LNG imports are delivered into the regional grid from three LNG facilities in New England - Distrigas in Everett, Massachusetts, the Northeast Gateway facility completed in 2008 offshore Cape Ann, Massachusetts and the Neptune LNG facility completed in 2010 off the coast of Gloucester. The Distrigas facility, which has operated continuously since 1971, delivers gas into the Tennessee Gas Pipeline, the Algonquin Gas Pipeline, the Boston Gas component of National Grid (formerly KeySpan) system, the Mystic Electric Generating Station Units 8 & 9, and sends LNG by truck to LDC storage tanks throughout the region. The Northeast Gateway and Neptune facilities deliver gas into the Algonquin Gas Pipeline via the Hubline. Since 2010, both the Northeast Gateway and the Neptune facilities have been generally inactive.

2.3 Natural Gas Production Cost Assumptions

This section presents the assumptions underlying our projections of gas prices at the Henry Hub and in the Marcellus and Utica shale gas producing regions, as well as Henry Hub price forecasts.

AESC 2015 recognizes that the Marcellus/Utica shale will be the primary source of gas supply to New England throughout most of the planning horizon, but there is as yet an insufficiently reliable history of pricing data in the Marcellus/Utica region. In addition, no clearly dominant price reference point has yet emerged in that region as of year-end-2014, most likely because its production growth has been so quick. As a result, AESC 2015 relies, as part of its forecast model of the avoided cost of gas in New England, upon a projection of gas prices at Henry Hub, where economic and gas pricing data remain unparalleled.

The major demand and supply factors expected to drive the price of gas over the study period include:

- Gas resources, reserves, production and the technologies that underlie each of these,
- The general availability, upstream of and apart from New England, of ample gas pipeline transportation capacity, and the consequently widespread impacts of low-priced shale gas throughout North American markets, but for New England,
- Regional, national and, increasingly, international economic activity,
- Advances in technologies for gas production, transportation and use, e.g., notably in the past decade, respectively, horizontal drilling, advanced LNG systems, and high-efficiency gas-fired electricity generation using combined-cycle combustion turbines (CCGTs),
- Price elasticity of natural gas in each use and cross-elasticity with oil, electricity and other competing fuels, and
- Infrastructure expansion, including pipeline and storage capacity.

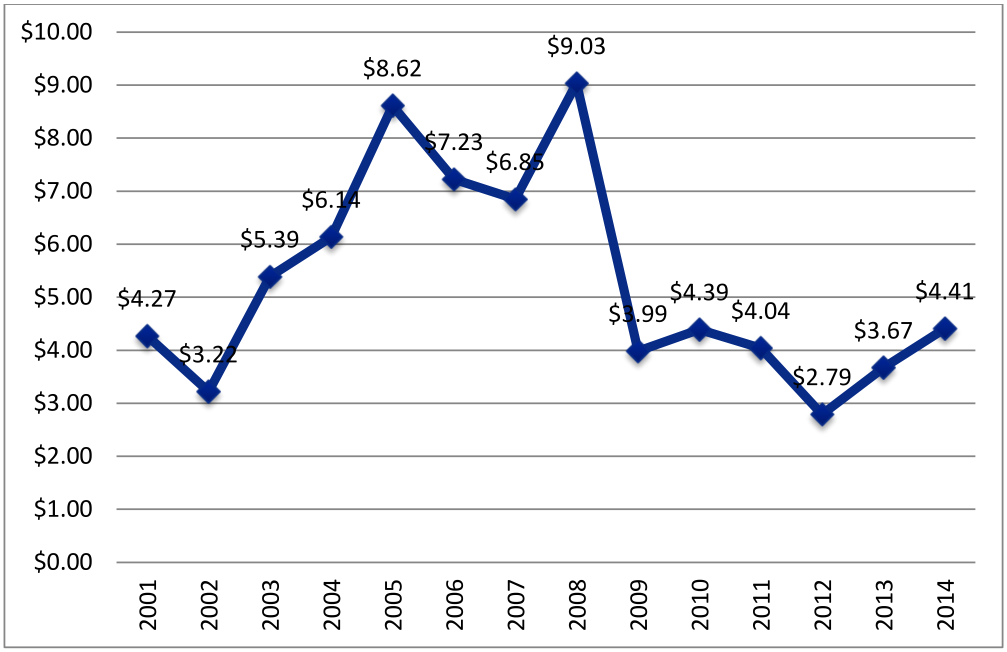
2.3.1 Major drivers of Natural Gas Production Costs over the past 30 years

For the past three decades, market forces of supply and demand have set prices for natural gas delivered into pipelines from producing areas throughout the U.S. and Canada.[12]

1980s-1990s (low conventional gas price era). Pressure from low-priced spot gas transformed U.S., then Canadian markets. The old-era pipeline-producer sales and purchase agreements (SPAs) were bought out, restructured, and otherwise disappeared, while spot and other negotiated gas markets surged to dominate the industry. By 1993, pipeline gas had disappeared from the market, and gas prices remained low in North America for nearly a decade. During this period, NYMEX launched its gas futures contract, which became their second most traded contract, after crude oil. A large number of gas-fired power plants began construction as well, including numerous cogeneration and combined-cycle plants in New England, buoyed by low gas prices and growing confidence in the now unregulated gas commodity markets. Most of the gas trading mechanisms described above evolved in the 1980s-to-2000 period as well, all within an environment of low gas prices.

[12] Decontrol of U.S. natural gas prices at the wellhead took effect initially under the Natural Gas Policy Act of 1978 (PL 95-621) in mid-1983, and was later codified under the Natural Gas Wellhead Decontrol Act of 1989 (PL 101-60).

Exhibit 2-6. Average Annual Henry Hub Gas Prices since 2000 ($/MMBtu)



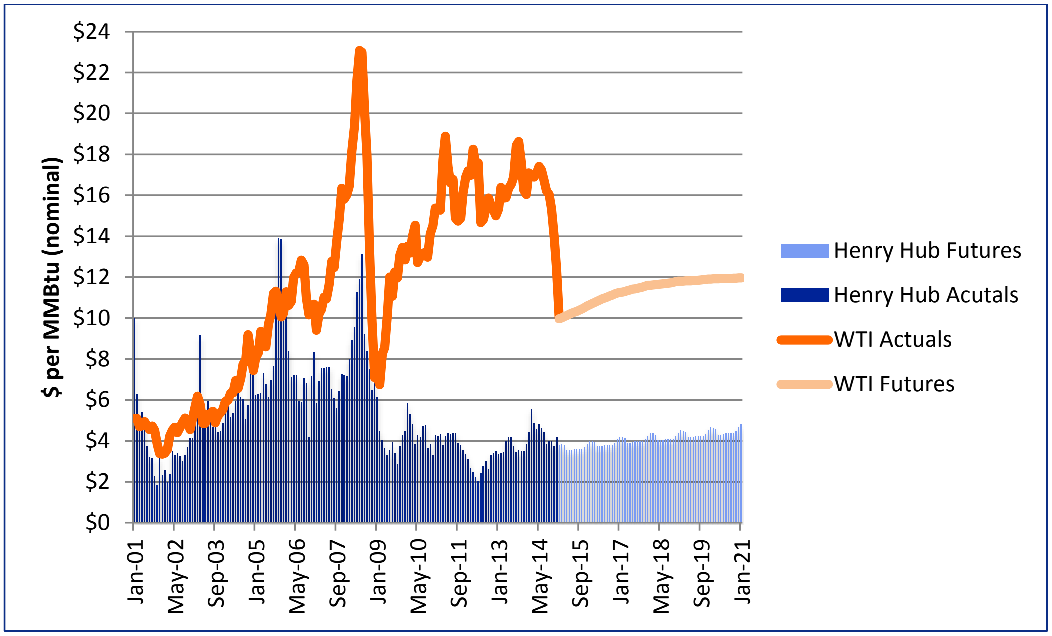
2000-2008 (second era of gas shortages). Rising gas demand for electricity generation throughout the U.S. forced higher gas prices and contributed to a series of price spikes that restored a general expectation of gas shortages. During this period, annual average Henry Hub prices rose from $4.00 per MMBtu up to range of $7.00 to $9.00 per MMBtu as indicated in Exhibit 2-6. During this period, delivered gas prices at times exceeded delivered fuel oil prices in New England, and seemed in national markets to track crude oil closely, as indicated in the actual monthly spot prices plotted in Exhibit 2-7. North America undertook a second wave of LNG import terminal construction, completing nine of them, including the Canaport terminal in New Brunswick that feeds LNG directly into New England via the Brunswick Pipeline and Maritime & Northeast Pipeline (M&NP). Also, Brent crude and WTI were closely correlated in this era.

2009-2020s and possibly beyond (the "shale revolution"). Widespread and quickly rising gas production from shale has obliterated the shortages mentality, and gas markets became quickly saturated, and then overwhelmed.[13] As illustrated in Exhibit 2-7 any price relationship that had existed between Henry Hub gas and crude oil completely disappeared, whether WTI or Brent. Henry Hub prices sunk to the $3.00-$4.00 per MMBtu range, where they remain at year end 2014. Familiar basis relationships around the North American continent have been upended, especially with increased – and still increasing – gas production from the Marcellus/Utica shales. Henry Hub, which since 1990 has spoken for the North

[13] The U.S. oil-versus-gas drilling rig count remains at about 4:1, according to data issued by Baker Hughes.

American continental gas market, is weakening as a price reference point, especially for pricing of gas in the regions between it and the Atlantic Ocean, including New England.

Exhibit 2-7. Monthly Prices of Natural Gas and Crude Oil – Actuals and Futures, 2001-2020



Source: CME-NYMEX, settlement prices at December 12, 2014; note figure plots past monthly spot prices for Henry Hub gas and WTI crude oil, as well as recent closing futures prices on CME-NYMEX for each of these same two commodities.

2.3.2 The "Shale Revolution"

The so-called "Shale Revolution" that has been underway since the latter part of the previous decade refers to an unprecedented rise in gas production, and more recently, oil production as well, extracted from shale and other source rock beneath the earth's surface.

It is an overarching assumption of this forecast that the "Shale Revolution" can no longer be viewed as a temporary, fleeting phenomenon but is here to stay, at least over most of the life of this forecast (herein, the "planning horizon"). Recent increases in US gas production from shale are shown in Exhibit 2-8. As the exhibit makes clear, production increases have taken place over a short period of time, accelerating in the past half-decade from a relatively low base of activity. As recently as seven years ago, in January 2008, for example, natural gas produced from shale in the US had only just surpassed 6 Bcf/day, or about 10% of US gas production in 2008. In contrast, by year-end 2013, shale gas production was meeting 40.6% of US natural gas requirements (see Exhibit 2-9), a proportion that had risen to 43.2% by August 2014, and seemed likely to surpass 50% in 2015 or 2016.[14] All the while, total US gas

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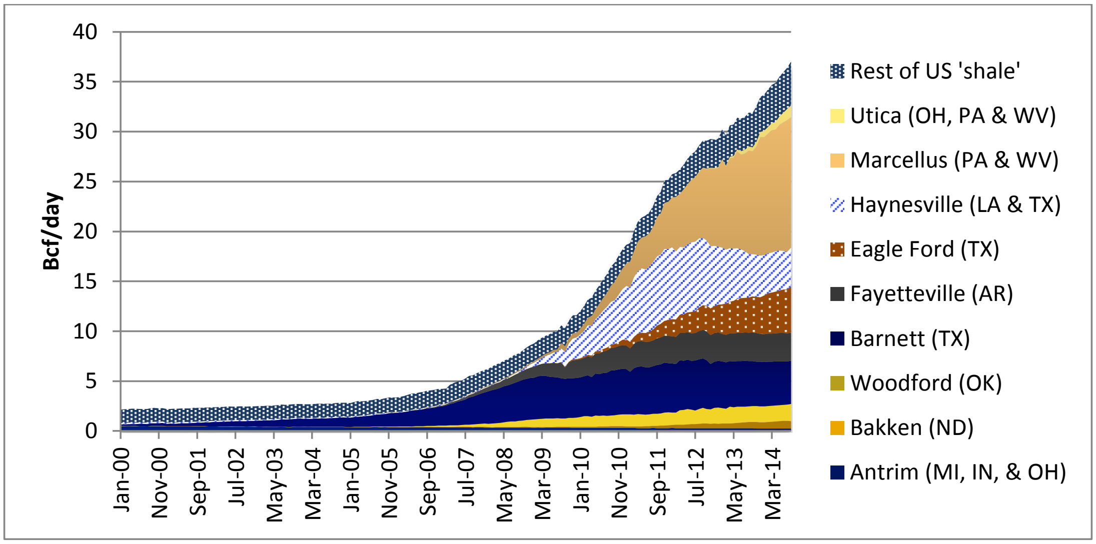
14 Based on EIA data and forecasts, op.cite.

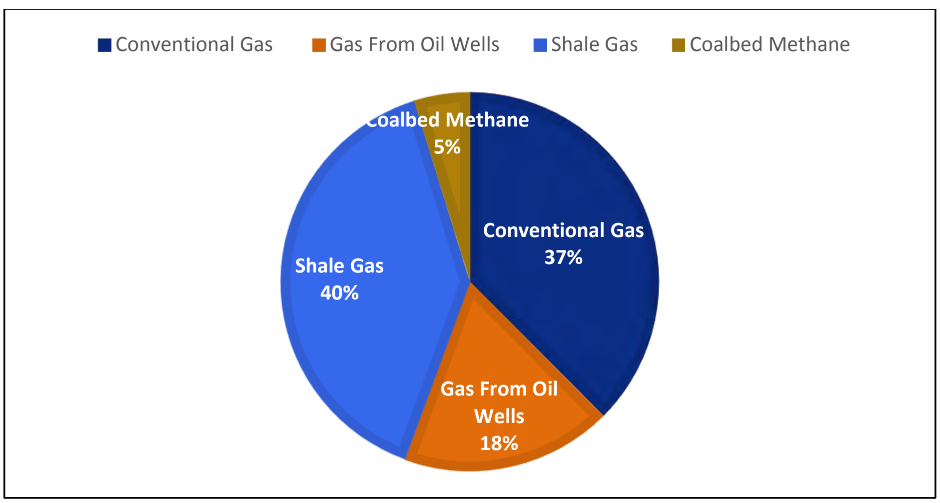
production has been rising, although not as quickly as production from shale, indicating that conventional resources are being crowded out to an extent by low-cost shale gas.

Exhibit 2-8. Increase in U.S. Natural Gas Production from Shale Fields, Monthly through August 2014



Source: EIA Administrator Adam Sieminski, in presentation before the US-Canada Energy Summit, Chicago, IL, October 17, 2014; compiled from state administrative data collected by Drilling Info Inc. Data are through August 2014 and represent EIA's official tight oil & shale gas estimates, but are not survey data. State abbreviations indicate primary state(s).

Exhibit 2-9. Derivation of U.S. Natural Gas Supplies, 2013



Source: EIA 2014, Natural Gas Gross Withdrawals and Production Volumes in 2013 (http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm).

As shown in Exhibit 2-10, the Marcellus and Utica shales have proved to be especially productive. Together, these fields supplied about 20% of the entire US gas market at year-end 2014 – and a far higher percentage of the New England market – this from de minimus production levels only a half-decade earlier.[15] Averaging approximately 18.4 Bcf/day by February 2014 and rising by more than 0.3 Bcf/day per month,[16] the Marcellus/Utica shales have increased to the point where they are physically supplying nearly all of the gas requirements in the U.S. Northeast and New England, apart from imported LNG into New England.

A number of reasons are cited by Kuuskraa (2014) to explain why shale gas and oil production has evolved so quickly – these largely relate to improving drilling technologies and rig efficiencies, and also the presence of traded gas markets with open access on interstate pipelines:

- Improving well performance – longer well laterals, increasing number of fracturing stages, widespread availability of accurate well log data enabling reduction in the percentage of "dry holes" down to nearly zero
- Major efforts to reduce costs – increasing rig efficiencies, reduced well stimulation costs, reduced set-up and production timing
- Production of associated gas from "tight oil" plays – break-even costs of associated natural gas from "tight oil" are low to negative
- Steady introduction of new gas plays to counter resource depletion.[17]

The foregoing improvements in gas production have taken place within an environment of extensive field knowledge and experience gained from decades of drilling activity in conventional gas and oil plays located within the same regions as the major shale plays.

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[15] EIA Drilling Productivity Report for Key Tight Oil and Shale Gas Regions ("EIA Drilling Productivity Report"), February 2015: 16,550 MMcf/day and 1,854 MMcf/day, respectively for Marcellus and Utica shales (see http://www.eia.gov/petroleum/drilling/#tabs-summary-2); and EIA Natural Gas Gross Withdrawals and Production, 2,674,827 MMcf in September 2014 (http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm).

Note these volumes update even some very contemporary publications and articles relying on earlier or inaccurate data, e.g., article in Nature Magazine, "Natural gas: The fracking fallacy," by Mason Inman, 03 December 2014, where Marcellus Shale is depicted as peaking in 2020 at about 12-13 Bcf/day (120-130 Bcf/year) in 2020, despite current production cited earlier in this note, as reported by EIA, of 18.4 Bcf/day, including the adjacent Utica shales. See, further, December 2014 responses to the Nature Magazine article by EIA and the University of Texas, Bureau of Economic Geology (http://www.eia.gov).

[16] EIA Drilling Productivity Report, January 2015, as above.

[17] Vello Kuuskraa, President, Advanced Resources International, Inc. (ARI), in presentation before the Electric Power Research Institute (EPRI) 33rd Annual Fuel & Planning Seminar, Washington, DC, November 12, 2014.

Exhibit 2-10. U.S. Shale Gas Production and Rate of Increase at Year-End 2014

Region	February 2015 Gas Production, Bcf/d	Monthly Change at January 2015 MMcf/d	Monthly Change at January 2015, %
Marcellus/Utica	18.4	+305	1.7%
Eagle Ford	7.5	+97	1.3%
Haynesville	7.0	+69	1.0%
Permian	6.3	+74	1.2%
Niobrara	4.7	+41	0.9%
Bakken	1.5	+27	1.8%
Total	45.4	+613	1.4%

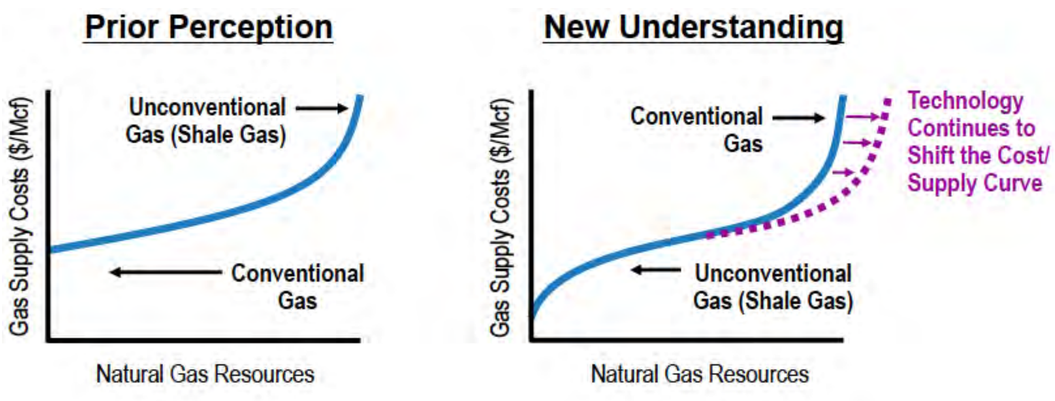
Source: EIA, Drilling Productivity Report, January 2015.

Natural gas production from the Marcellus/Utica shales has benefited greatly from its ability to access an extensive existing pipeline grid. This gas has generally been able to travel to where it is consumed on a "non-firm" basis, and gas sales take place within flexible, liquid, efficient spot gas markets. The one major exception has been pipeline capacity to the Northeast and New England during winter months. The lack of adequate firm pipeline capacity to deliver gas from the Marcellus/Utica shales to those regions has caused the wholesale market price of gas in New England to skyrocket during the past two winters, and in the Northeast last winter.

Kuuskraa (2014) goes on to explain that, under past perceptions, conventional gas and oil was cheaper to produce than unconventional resources such as shale, tight sands, tight oil, and the like, which require well stimulation techniques of one kind or another. In Exhibit 2-11, he makes the point that conventional gas used to occupy the lower left-hand portion of the overall US price-quantity gas supply curve, while unconventional resources occupied the upper right-hand portion. In other words, gas from ordinary downward-only (vertical, un-stimulated) gas wells was cheap to drill and produce, despite a number of finding risks like imperfect success rates. On the other hand, the nation's vast unconventional gas and oil resources have long been documented, but they were deemed too expensive to produce because well stimulation would be required at high cost (as was believed at the time).[18]

As Kuuskraa points out: "Today, unconventional gas (particularly high quality, liquids-rich shale gas) forms the low-cost portion of the natural gas cost/supply curve."[19]

Exhibit 2-11. Illustrative Price-Quantity Curve for Overall U.S. Natural Gas Supply



Source: Kuuskraa, 2014, before EPRI (see Footnote 6).

In summary to this discussion, the AESC 2015 forecast of avoided gas costs in New England has as its overarching assumption that shale gas is here to stay as a dominant component of U.S. gas supplies, comprising at least 50% of the nation's gas supply through the planning horizon.[20] Even despite lowered energy price expectations, shale gas will continue to depress underlying North American natural gas prices for at least two decades (see discussion below), will replace other supplies of gas as well as fuel oil and coal, and will obviate otherwise inevitable LNG imports.

2.4 The Marcellus and Utica Shales

The Marcellus/Utica shale field has become the nation's largest gas producing field, with no exceptions. Centered in Pennsylvania, Ohio and West Virginia, the Marcellus and Utica shales (herein, Marcellus/Utica) are estimated to hold one of the largest gas fields discovered in the history of the global industry, i.e., about 410 trillion cubic feet (Tcf) of undeveloped technically recoverable gas. For perspective, the Marcellus/Utica is estimated to hold about twice the recoverable gas resources of Alaska's North Slope. Improving technology and field practices tailored to the Marcellus/Utica have

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[18] For example, see EIA and Gas Research Institute reports, and legislative history of the Natural Gas Policy Act of 1978.

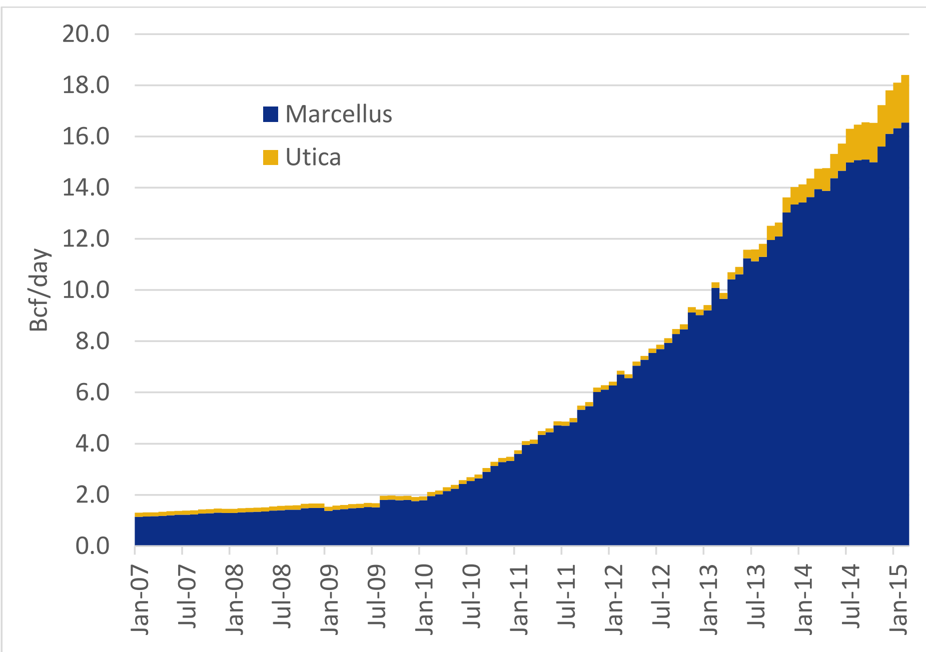
[19] Ibid. Kuuskraa before EPRI, November 2014.

[20] Discussion of health and safety impacts of the major shale production technique, hydraulic fracturing combined with horizontal drilling, may be found in later portions of this chapter.

enabled this gas to be produced at lower costs than most other gas plays in the US, including other shale fields.

Even though it is now already producing more than twice as much gas as any other field in the U.S., shale or otherwise, Marcellus/Utica production is continuing to increase (see Exhibit 2-12). Gas production has been rising by about 1 Bcf/day every three months since 2011, and is likely in our view to reach an average daily production range of about 20-25 Bcf/day by 2020. By contrast, Alaska's proposed North Slope gas pipeline was to have delivered from 4 Bcf/day to 7 Bcf/day of gas, depending upon various pipeline configurations that have been offered in the past nearly four and one half decades since North Slope oil and gas was discovered in 1968.

Exhibit 2-12. Marcellus/Utica Shale Gas Production Growth, Million cf/day



Source: EIA Drilling Productivity Report, January 2015.

As a result of unexpectedly major volumes of natural gas produced in the Marcellus/Utica, a number of gas pipeline flows have been reversed in the U.S. in order to transport gas out of the Marcellus/Utica shale to Chicago, Central Canada, and even to Louisiana and Texas.

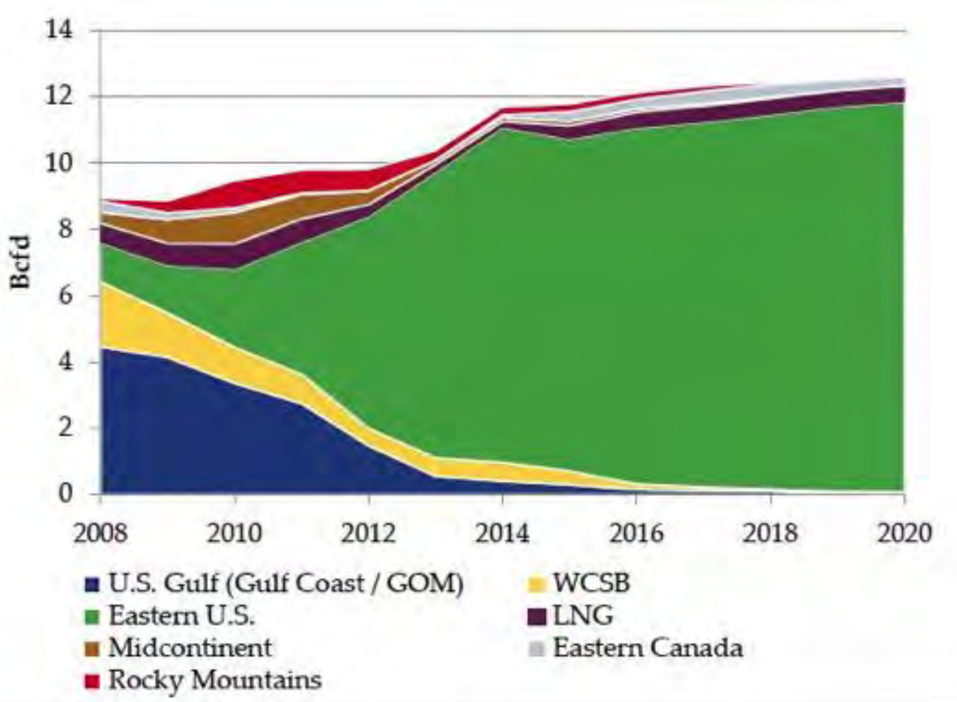
The foregoing developments are having important spillover effects on New England's gas supply sources:

- First, Marcellus/Utica gas is largely displacing New England's traditional gas supplies from U.S. southwestern producing areas including Louisiana and Texas.

- At the same time, as described above, the international gas import point at Niagara through which Canadian gas has for thirty years entered New York State, bound in part for New England, was recently reversed and Marcellus/Utica gas is currently flowing into Central and Eastern Canadian markets. This gas is increasingly displacing gas produced in the Western Canadian Sedimentary Basin (WCSB) which, for decades, supplied essentially all of this region's gas requirements via the TransCanada pipeline system mainline.
- Thus, since Central and Eastern Canada is increasingly consuming Marcellus/Utica gas instead of WCSB gas as shown in Exhibit 2-5, most of New England's gas supplies from Canada, e.g., via the Iroquois and Portland Natural Gas pipelines, is actually Marcellus/Utica gas as well – and all of it is on the margin. In other words, whether New England wholesale buyers move gas on the Algonquin or Tennessee Gas pipelines from New York State, or they import pipeline gas from Central Canada (Ontario and Quebec), they are in reality acquiring gas mostly from the Marcellus/Utica producing region.

AESC 2015 assumes that production from the Marcellus/Utica shales will continue to increase and to supply an increasing portion of the New England market over time, eventually supplying almost the entire pipeline (i.e., non-LNG) market through the following two decades, and then largely beyond then through the end of the planning horizon (see Exhibit 2-13, from OEB/Navigant 2014)

Exhibit 2-13. Sources of Gas Supply in the U.S. Northeast Region, Including New England



Source: 2014 Mid-Year Outlook, from Ontario Energy Board, 2014 Natural Gas Market Review, Navigant Consulting, Inc., December 2014, page 36.

In addition, as was assumed in the AESC 2013 forecast of avoided gas costs, AESC 2015 anticipates that New England will continue to rely on imported LNG to help meet its winter peak gas demand requirements for a limited number of days.

2.5 Long-Run Avoided Cost of Gas Supply

The AESC 2015 Base Case and High Gas Case forecasts from January 2017 onward rely on Henry Hub gas price projections contained in the Energy Information Administration's Annual Energy Outlook (AEO) 2014 Reference Case.[21] The AESC 2015 Low Gas Case sensitivity forecast relies on the AEO 2014 High Oil and Gas Resource Case (HRC). These forecasts were selected based upon our review of the AEO 2014 suite of forecasts, as well as on runs of the World Gas Model housed at Deloitte and at the James A. Baker III Institute for Public Policy at Rice University (Baker-WGM), current futures market prices of gas and basis, and insights from other research agencies and consulting firms**.**

Unlike AESC 2013, AESC 2015 does not adjust AEO 2014 forecasts for marginal well economics or compliance with anticipated tighter regulation of fracturing, as no such corrections are needed. This decision is based upon the reviews described above, on our understanding that these factors have been internalized in EIA's contemporary rounds of AEO forecasts, and on recent data.

2.5.1 Reliance on AEO 2014 Reference Case

EIA's annual domestic energy forecasting process involves an annual cycle consisting of analysis activity conducted internally and through use of contractors. The process takes place largely during the summer preceding the date of (and release of) AEO forecasts, thus the bulk of work in preparing the AEO 2014 Reference Case took place predominantly during Summer 2013. The EIA's analysis involves preparing and testing necessary updates to, and changes in the National Energy Modeling System (NEMS), including numerous runs and reruns of the updated model. Throughout this process, a series of peer reviews are conducted with industry experts and stakeholders. This series of activities normally intensifies during the summer and fall preceding EIA's issuance of the early release of its Reference Case, normally in mid-December. The AEO 2015 preparation cycle has been delayed to accommodate the more than 50% decline in crude oil prices that took place in the latter half of 2014, as well as other recent developments.

In the High Oil and Gas Resource Case (HRC), the EIA makes a number of assumptions about the unconventional gas and oil resource base that, together, expand recoverable gas volumes well beyond

[21] The AESC 2015 High Gas Case Henry Hub price is the AEO 2014 Reference Case plus 15%, which reflects the minimum increase in gas prices in the AEO 2014 Low Oil and Gas Resource Case over the AEO 2014 Reference Case.

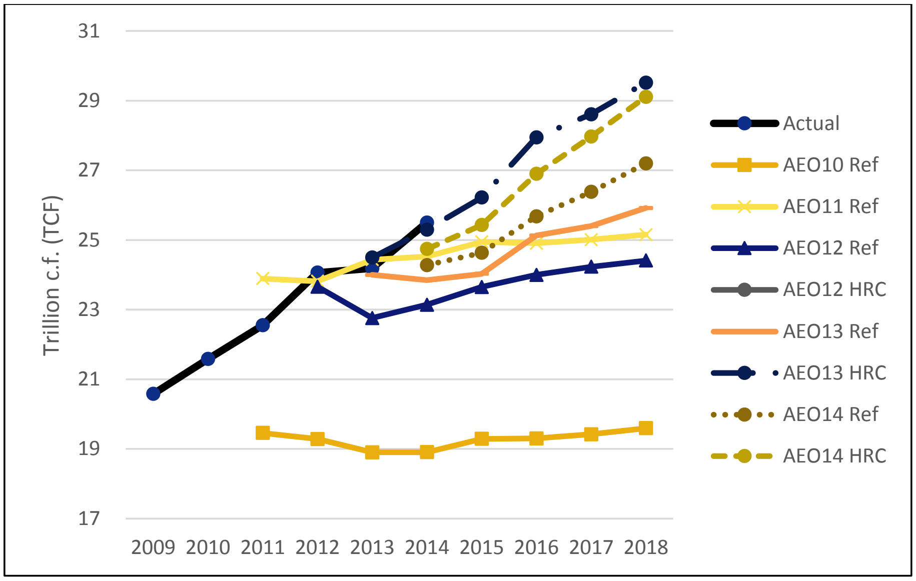
those assumed in the Reference Case. The HRC makes no other changes to the AEO Reference Case assumptions, e.g., contains no differences in assumptions concerning existing drilling laws and regulations, macro-economic conditions, or about other fuels. [22] Importantly, the HRC assumes that the estimated ultimate recovery (EUR) of shale and tight sands gas is 50% higher than in the Reference Case and the number of wells left to be drilled is 100% higher. In the AEO 2013 and AEO 2014 versions, the HRC forecasts project significantly lower gas prices than the corresponding Reference Cases.

In our analysis, the HRC series has been a closer predictor of the growth in shale gas production than has the Reference Case series. As shown in Exhibit 2-14, AEO Reference Cases in recent years have been consistently low in their projections of U.S. dry gas production, while the HRC series has come closer to reality. The situation with respect to AEO forecasts of gas prices has not been as clear as it has been with volumes however. For example, we note that, in some years, AEO Reference Cases have come closer to forecasting actual gas prices than the HRC cases. As shown in Exhibit 2-14, the EIA forecasts that appear to have come closest to projecting actual prices have been the AEO 2013 Reference Case – which was the driving forecast in the AESC 2013 report – and the AEO 2014 HRC.[23]

[22] The EIA defines the HRC as follows: "Estimated ultimate recovery per shale gas, tight gas, and tight oil well is SO% higher and well spacing is 50%lower (or the number of wells left to be drilled is 100% higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays and the estimated ultimate recovery for tight and shale wells is increased 1% per year to reflect additional technological improvement. Also includes kerogen development, tight oil resources in Alaska, and 50% higher undiscovered resources in lower 48 offshore and Alaska than in the Reference case." See, for example: http://www.eia.gov/oiaf/aeo/tablebrowser/.

[23] Note that, through the late 2020s, the AEO 2013 Reference Case and the AEO 2014 High Oil & Gas Resource Case are almost identical in terms of their projected Henry Hub gas price; after that, these diverge, as the AEO 2014 High Oil & Gas Resource Case decreases to meet NYMEX market general expectations.

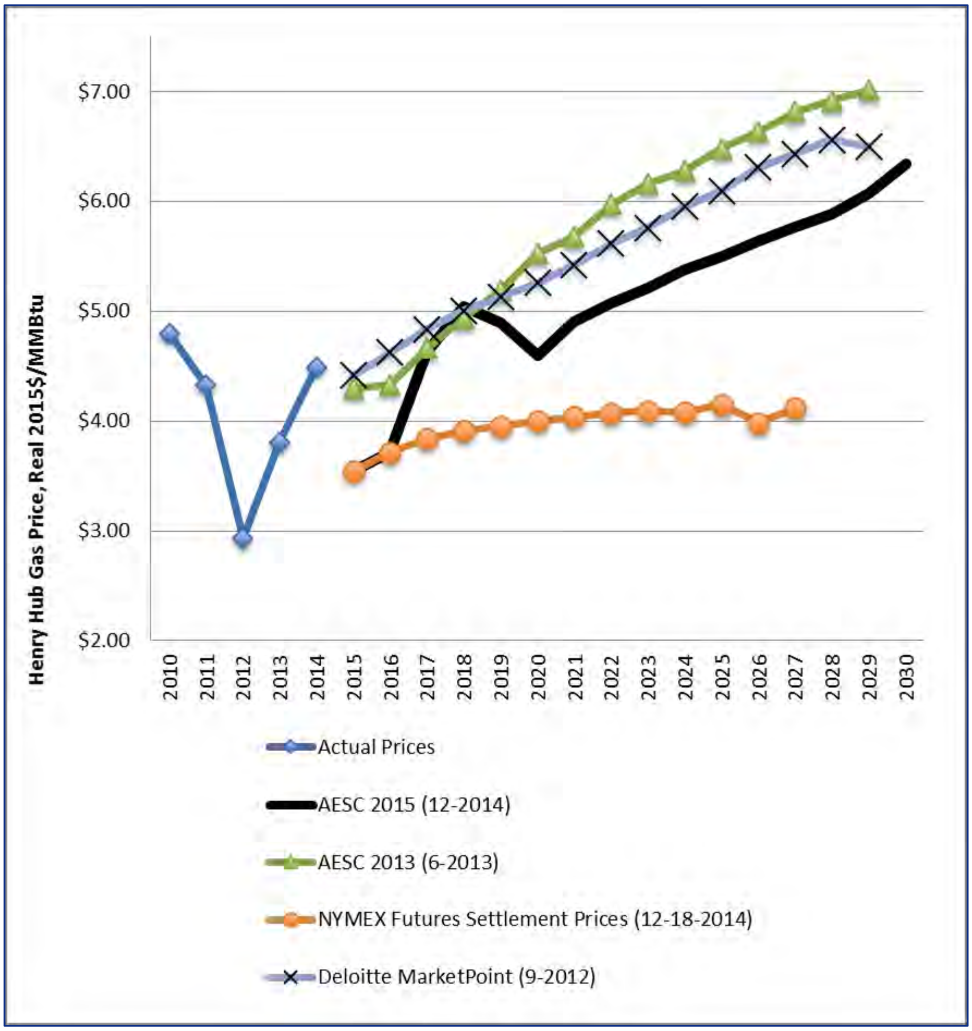
Exhibit 2-14. Comparison of U.S. Gas Production Forecasts in Recent AEO Forecasts vs. Actual Gas Production



Consequently, AESC 2015 opts on the conservative side and derives its Henry Hub gas price assumptions largely from the AEO 2014 Reference Case. It must be pointed out, however, that no statistical proof could substantiate selection of any particular case in a meaningful way on the basis of price, in light of the wide risks and uncertainties confounding all Henry Hub gas price forecasts at a time when:

- Gas production is growing rapidly.
- Production is moving away from the traditional southwestern producing regions, to the Marcellus/Utica region.
- Crude oil prices are highly unstable, having fallen almost suddenly by about 50% in the latter half of 2014.
- Coal competition with natural gas remains sharp.
- LNG exports are poised to begin in about a year, starting with initial exports of U.S. LNG from the Sabine Pass LNG terminal in November 2015.

Exhibit 2-15. Comparison of Annual HH Prices – Actuals, AEO Forecasts and December 2014 NYMEX Futures



In addition, as if the foregoing uncertainties were not great enough, around the time the AESC 2015 report was prepared, the EIA announced it intended to delay early release of its AEO 2015 Reference Case until March 2015.

2.5.2 Marginal Production Cost of Natural Gas from Shale

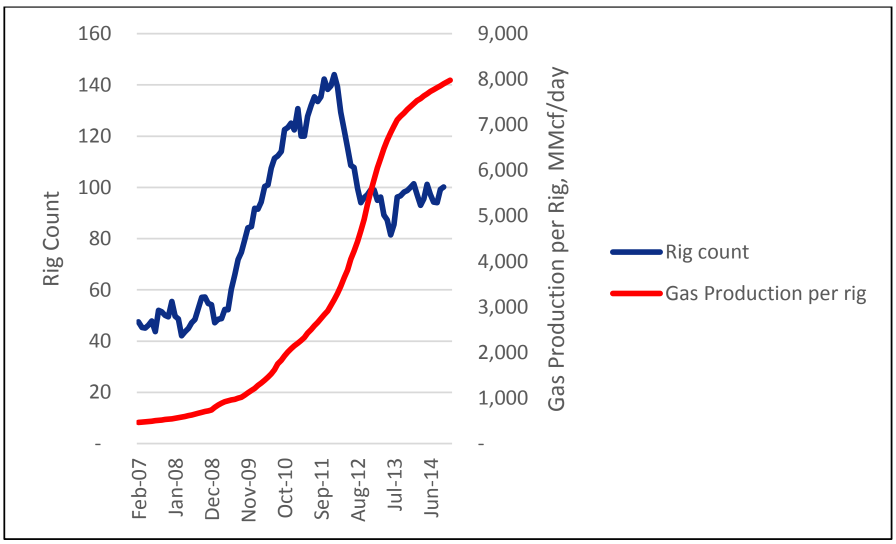
Since the AESC 2013 report was prepared and issued, EIA has expanded the data it provides that are related to the marginal cost of gas production from dry-gas prone and liquids-prone shale plays. In particular, data contained in EIA's new monthly publication, the Drilling Productivity Report (DPR), suggests considerable economies are evolving in production from each of these kinds of shale fields.

The DPR series was begun in October 2013 to address the paradox of rapidly rising gas production per well, and rising gas production overall, in the Marcellus despite a sharply falling rig count in 2011-2012.

Analysts of U.S. shale gas activities had long assumed that falling gas prices would result in a falling rig count, which would then, in turn, quickly reduce gas production. Fundamental reasons for accepting this sequence – and its reverse: rising prices lead to rising rig counts, which lead to more gas production – include the relatively small scale of individual shale well drilling operations and their steeply production decline rates on an individual basis. In addition, the speed with which rigs can be moved, deployed and removed have been a factor. But the key missing element in understanding why and how shale gas production could grow so rapidly has been the increase in rig productivity, i.e., production of gas per drilling rig, per unit of time, brought about by improved technology, tighter operating practices, and increased drilling efficiency.

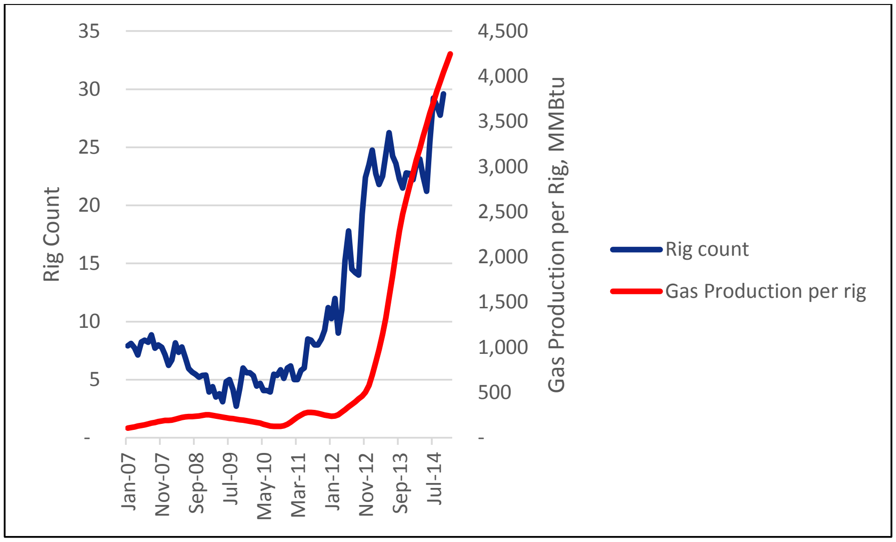
The dramatic growth in drilling productivity in the Marcellus and Utica regions, shown in Exhibit 2-16 and Exhibit 2-17, explains why production is rising despite the declining rig count.

Exhibit 2-16 Rig Count vs. Rig Productivity: Marcellus Shale



Source: EIA Drilling Productivity Report, November 2014.

Exhibit 2-17 Rig Count vs. Rig Productivity: Utica Shale



The increases in gas production shown in those two exhibits have been realized in other shale formations as well, and are echoed in rising oil production statistics as well as for gas. Unlike a "learning curve" in the usual sense, these advances are more a reflection of technological, management and operating improvements that have been tailored to each producing field.

Inclusion of rising rig productivity has been a major, necessary correction to U.S. gas price forecasts. In particular, we understand that the current version of EIA's NEMS model is taking the foregoing kinds of drilling productivity improvements into consideration in development of the AEO 2015 forecast. The NEMS Model contains an Oil & Gas Module, which is used to project gas production based on costs of developing resources in each U.S. gas-producing region. NEMS' Oil & Gas Module anticipates continued improvements in rig and program efficiencies as drilling moves beyond core areas in each shale field.

In its comprehensive documentation report, EIA summarizes its approach in the following general statement:

> The general methodology relies on a detailed economic analysis of potential projects in known crude oil and natural gas fields, enhanced oil recovery projects, developing natural gas plays, and undiscovered crude oil and natural gas resources. The projects that are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. The economic production from the developed projects is aggregated to the regional and the national levels. (EIA 2011)

In its 2013 methodology update, which describes methodology underlying the AEO 2014 cases, the EIA indicates that the Oil & Gas Module contains production cost data in all categories, much like a group of natural gas supply curves. A gas supply curve refers to a price-quantity curve that contains the marginal cost of producing additional volumes of gas from that field or play covered in that curve. A gas supply curve in this manner is implicit in each of the 85 gas-producing fields listed in its AEO 2014 assumptions report, which includes ten subfields of the Marcellus, Utica, Devonian and other nearby shales. In each case, the EIA's estimate includes production costs for marginal wells throughout the entire unproved technically recoverable tight/shale oil and gas resources, by play. The EIA's gas supply methodology, therefore, embeds the costs of producing each component of the resource, sequenced by rising costs – starting with the low-cost core interior, through the next higher cost fields in the area, and on to the higher marginal cost portions, then the highest cost components.

As a consequence, therefore, there is no longer any reason to add or subtract any special factors to adjust EIA's forecasts for marginal well economics – these are embedded in EIA's supply analyses underpinning the AEO suite of forecasts, including each component of the Marcellus/Utica shales.

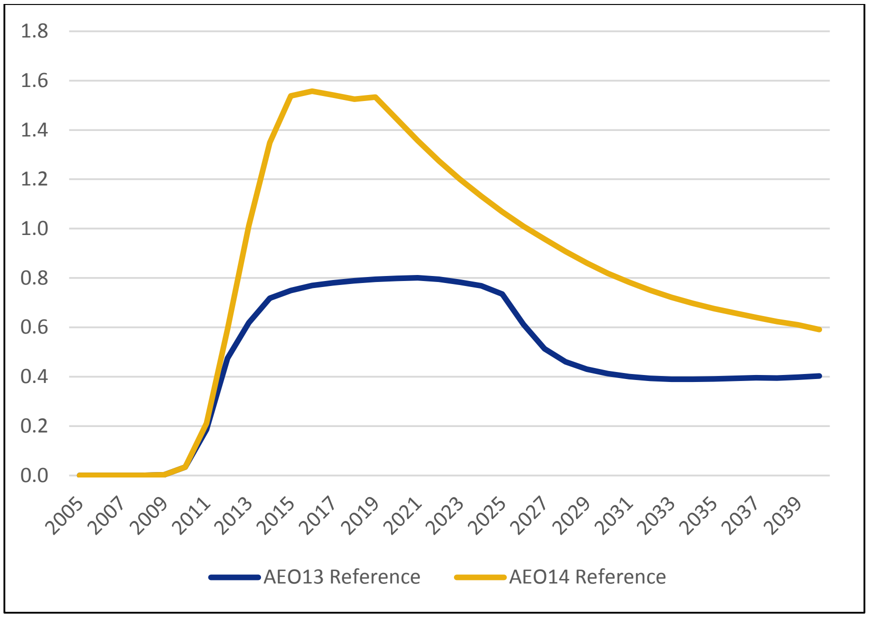
2.5.3 Inherent Limitations in AEO Reference Cases

Despite its widespread usefulness and acceptance, AEO Reference Case forecasts are necessarily bound to reflect law and regulations in effect at the time of the forecast.[24] In addition to assumptions about the economy, assumptions concerning technology and the extent of recoverable oil and gas resources in the Reference Case are consistent with understandings that are in existence or viewed as most likely, at the time the analysis is prepared, e.g., summer and autumn of each year for the following year's forecast. As discussed above, considerable uncertainties surround any energy forecast, let alone one produced amidst the aggressive pace of change taking place in the U.S. oil and gas industry in all respects. As a consequence, EIA's numerous sensitivity cases – particularly the High Oil and Gas Resource Case ("HRC") – take on particular significance.

[24] In the AEO 2014 Reference Case, real GDP grows at an average annual rate of 2.4% from 2012 to 2040. Crude oil prices are projected to rise to about $141/barrel (2012 dollars) in 2040. Note that the AESC 2015 forecast includes a downward adjustment to oil price projections in AEO 2014 Reference Case, as described in the accompanying section on fuel oil avoided cost assumptions, methodology and forecasts.

For example, contrast the analysis of tight oil production in the Eagle Ford by Dana Van Wagener (Wagener, EIA April 2014) with the most recent edition of EIA's Drilling Productivity Report shown in Exhibit 2-18. These differences demonstrate how difficult it is to project rising production and falling costs of shale resource development at a time of when both features – production volumes and production costs – are changing rapidly.

Exhibit 2-18. Eagle Ford Crude Oil Production in the Reference Case, 2005-40 (million bbl/day)



Source: Wagener, EIA April 2014; see preceding footnote.

As Wagener demonstrates (see Exhibit 4 2), the AEO 2013 Reference Case projected the Eagle Ford crude oil production would level off at less than 800,000 barrels per day for about a decade; then, the AEO 2014 Reference Case projected the Eagle Ford would level off at just over 1.5 million barrels per day. Timely EIA data indicate the Eagle Ford is currently producing 1.7 million barrels per day as of December 2014. Similar under-estimates of shale oil and gas production in EIA's reference cases are numerous – especially for gas production from the Marcellus/Utica shales.

The foregoing argues convincingly for caution in the use of the AESC 2015 forecast of avoided gas costs in New England because this forecast relies extensively on the AEO 2014 Reference Case.

2.5.4 Summary of Forecasting Issues in AESC 2015

The AESC 2015 Base Case and High Case forecasts rely on the AEO 2014 Reference Case (High Case is a 15% upward price adjustment from the AEO Reference Case),while the AESC 2015 low gas Case relies on the AEO 2014 High Oil & Gas Resource Case (HRC). Over the past several years the AEO HRC series have more closely tracked the pace of gas production increases in the recent past than have the Reference

Cases. AEO Reference Case forecasts prior to and including AEO 2014 have tended to underestimate production from shale gas and, in some cases, over-estimate wellhead prices from those plays.

Crude oil prices decreased by 50% in a matter of months during the second half of 2014. As described in Chapter 3), experienced analysts advise that prices may fall even lower amidst a gathering price war. But like prior price wars, peace is likely to 'break out' as most OPEC member budgets (and some non-OPEC budgets as well, e.g., the Russian Federation) strain to the breaking point, forcing cooperative action.[25] If domestic crude oil prices were to remain in the $60-$70 per barrel range for the next five years, drilling activity in some strongly crude-prone, high-cost plays may decrease markedly, e.g., the Bakken, Niobrara and Canadian oil sands regions, as these areas generally do not have the benefit of natural gas sales to help offset lower crude prices. Likewise, drilling in the liquids-rich Eagle Ford and Utica plays will not fall of as greatly because of their prolific gas production and excellent market access. Drilling in the Marcellus Shale may also be affected, but to a lesser extent, as the Marcellus is a dry gas play, thus it is not clear that low oil prices will have a material impact on production from that field.

With regard to LNG exports, AESC 2015 agrees with AESC 2013 assessment of the gas price impact of LNG exports. The only significant new study issued since then was EIA's report of October 2014,[26] which corroborates the conclusions in AESC 2013, namely, that the consumer price effects of LNG exports will be modest. But in any event, lower crude oil prices may reduce expected LNG exports from the U.S. because global natural gas prices are typically linked under long-term contracts to crude oil prices. This is the case in a number of likely receiving markets for LNG from the U.S., including Japan, South Korea, Central Europe, parts of Western Europe, and elsewhere. As global oil prices fall, therefore, global gas market prices beyond North America fall as well, and the economic margin tightens, reducing the gap between U.S. gas prices (plus liquefaction and shipping) and other gas prices internationally. Medlock, Hartley (Rice/Baker Institute) and others have argued that high costs of liquefaction and transportation of US gas to these markets would make some LNG exports uneconomic depending on how low world crude prices fall.27

2.6 Incremental Gas Production Costs Related to Compliance with Emerging Hydraulic Fracturing/Horizontal Drilling Regulations

Analysts have identified a number of potential sources of additional costs gas producers might incur in the future in order to comply with existing, impending or potential regulations governing hydraulic

[25] See, for example, Verleger (October 2014) and others in current discussions. Verleger sees little risk to the Marcellus as crude prices fall briefly, potentially to as low as $35 or $40 per barrel, but then recovery to the $60 to $70 range.

[26] EIA, "Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets," October 29, 2014.

[27] See, for example, Kenneth B. Medlock, "A Discussion of US LNG Exports in an International Context," Center for Energy Studies, James A Baker III Institute for Public Policy Adjunct Professor, Department of Economics Rice University, January 11, 2013 presentation before the National Capital Area Chapter of the U.S. Association for Energy Economics.

fracturing/horizontal drilling.[28] These potential sources of additional costs primarily involve water and wastewater treatment and disposal regulations, regulations governing the handling and/or elimination of toxic materials, and the need to reduce greenhouse gas (GHG) emissions and the wellhead and in the gas pipeline and distribution grid. AESC 2015 assumes that the long-term AEO 2014 Reference Case gas market forecast adequately reflects these potential additional costs, for the reasons discussed below.

2.6.1 Water and Wastewater Treatment and Disposal

In most basins, gas-bearing shale seams are located far beneath groundwater basins, e.g., shale seams are at depths ranging from 6,000 to 12,000 feet, while groundwater basins are typically at bottom depths of no more than 2,000 or 2,500 feet. Non-porous bedrock separates the two layers, i.e., shale seams are below even deep groundwater aquifers, thus preventing material from one layer from mixing into the other. Sealed drill-pipes routinely traverse aquifers to avoid direct contact with groundwater, although occasional instances of groundwater contamination caused by ruptured drill-pipe have been reported. Moreover, naturally occurring fractures or fissures in the bedrock may inadvertently provide transport channels among strata. In relatively rare instances where transport through the bedrock has been available, fracking pressures were suspected of driving native hydrocarbons from shale seams up into groundwater aquifers.

During the early years of the shale revolution, reports of benzene and other drinking water contamination near shale gas fracking operations prompted environmental regulators to restrict shale-drilling operations in some locations until a better understanding of the processes at work could be gained. In one celebrated case, New York City's water supply, which is derived from aquifers beneath five counties in the eastern fringe of the Marcellus Basin and transported through tunnels in the bedrock, was deemed sufficiently threatened to necessitate suspension of shale gas drilling operations in all five counties, and ultimately throughout the State.

In response to these concerns, the US Environmental Protection Agency (EPA) commenced an in-depth analysis of the foregoing issues with the goal of determining if the agency needs to regulate shale gas drilling operations under the U.S. Safe Water Drinking Act. In one widely-reported instance, a driller in Wyoming (Encana) conducted hydraulic fracturing (herein, "fracking") operations into shallow shale seams located quite near the aquifer, with the predictable result that groundwater became

[28] The AESC 2013 Forecast added to its gas price forecast a "fracturing best practices upward adjustment" rising to $.54 per MMBtu by 2021 and remaining at that amount through the planning horizon. However, despite its useful review of literature available at the time, this report offered no source documenting any such estimate, apart from an unreferenced 2010 report by the consulting firm of Tudor, Pickering. Any such 4-5 year old estimate would necessarily predate the rise in shale gas production in the US, particularly in the somewhat more recent Marcellus or Utica basins, and could not comprehend drilling improvements and efficiencies since then.

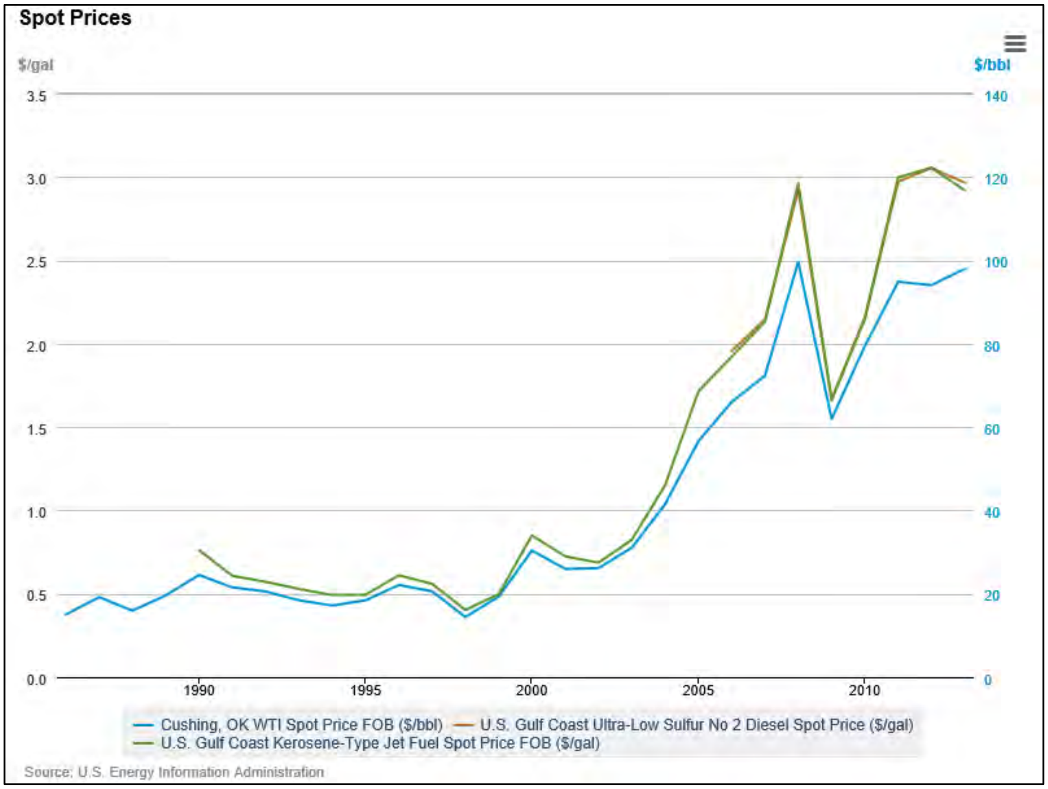
contaminated with materials contained in fracking waters and shale-borne substances. The EPA's report termed the incident exceptional.[29]

Fracking fluids consist largely of water and sand (as a propping agent), although some drillers also use a variety of other substances, including 1-2 percent concentrations of biocides, gels, and organic substances to improve performance. Some of the fluids injected into shale seams in fracking operations re-emerge in return water from wells under fairly high pressures ("flowback"). Flowback consists of much the same materials that went into the well, plus various other solids, hydrocarbons, and other materials resident within the shale seam. If not fully recycled, flowback is effectively an industrial effluent that must be treated and disposed of properly.

Before the price of liquids increased to very high values in 2011-2012 (as shown in Exhibit 2-19), flow-back in some drilling operations was handled in ways that contributed to wasting valuable liquid materials: some flow-back was spread on land away from aquifers to prevent leaching into groundwater, some was disposed of in adjacent waterways, and some was trucked off-site to public wastewater treatment plants for disposal to the extent of available capacity. The sheer volumes of flowback wastewaters, together with reported instances of impermissible wastewater disposal practices, excessive truck traffic, and the like, prompted regulators to examine shale gas operations more closely to ensure compliance with the U.S. Clean Water Act and other federal, state and local laws. More recently, as producers turned sharply to liquids-prone shale plays – particularly the Eagle Ford, Bakken, and others in relatively arid regions – they have been required to recycle flowback waters with greater frequency and intensity in order to maximize recovery of condensates, including benzene and other valuable liquids, and to use local water supplies more efficiently. In so doing, producers have also effectively minimized pathways to the groundwater associated with improper disposal of flowback wastewaters.

[29] Jim Martin, Region 8 Administrator, U.S. Environmental Protection Agency (EPA),before U.S. House of Representatives Committee on Science, Space, and Technology, Subcommittee on Energy and the Environment, Hearing on Ground Water Research at Pavillion, Wyoming, February 1, 2012, "It should be noted that fracturing in Pavillion is taking place in and below the drinking water aquifer and in close proximity to drinking water wells – production conditions different from those in many other areas of the country." (Martin testimony, page 4)

Exhibit 2-19. Crude Oil and Selected Petroleum Product Prices in Markets Adjacent to U.S. Southwestern Shale Regions



In summary, gas drilling operations have radically changed since the onset of the shale revolution, when many of the initial concerns surrounding "fracking" became voiced. Pennsylvania, Ohio, and other Marcellus/Utica states have tightened regulation, while gas prices have remained low all the while.

2.6.2 Methane Leakage

Methane, a greenhouse gas (GHG) that is the primary component of natural gas, is understood to be a far more powerful GHG than carbon dioxide, exceeding the strength of CO_2 in this respect by factors variously estimated to be 20-25 over a 100 year cycle.[30]

Overall, the present status of knowledge about natural gas and methane as a GHG was summarized in a working paper issued in 2013 by the World Resources Institute,[31] as follows:

[30] Steffen Jenner and Alberto J. Lamadrid, "Shale gas vs. coal: Policy implications from environmental impact comparisons of shale gas, conventional gas, and coal on air, water, and land in the United States," Energy Policy 53 (2013) 442-453.

[31] James Bradbury, Michael Obeiter, Laura Draucker, Wen Wang, and Amanda Stevens, "Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems," World Resources Institute, Working Paper, April 2013.

> 1. Fugitive methane emissions from natural gas systems represent a significant source of global warming pollution in the U.S. Reductions in methane emissions are urgently needed as part of the broader effort to slow the rate of global temperature rise.
>
> 2. Cutting methane leakage rates from natural gas systems to less than 1 percent of total production would ensure that the climate impacts of natural gas are lower than coal or diesel fuel over any time horizon. This goal can be achieved by reducing emissions by one-half to two-thirds below current levels through the widespread use of proven, cost-effective technologies.
>
> 3. Fugitive methane emissions occur at every stage of the natural gas life cycle; however, the total amount of leakage is unclear. More comprehensive and current direct emissions measurements are needed from this regionally diverse and rapidly expanding energy sector.
>
> 4. Recent standards from the Environmental Protection Agency (EPA) will substantially reduce leakage from natural gas systems, but to help slow the rate of global warming and improve air quality, further action by states and EPA should directly address fugitive methane from new and existing wells and equipment.
>
> 5. Federal rules building on existing Clean Air Act (CAA) authorities could provide an appropriate framework for reducing upstream methane emissions. This approach accounts for input by affected industries, while allowing flexibility for states to implement rules according to unique local circumstances.
> (Bradbury et al, 2013)

In response to increased gas drilling and a wide variety of methane emission estimates from numerous sources, the EPA issued on April 17, 2012, New Source Performance Standards (NSPS) governing GHG emissions from oil and gas drilling and producing activities. Under the rule, shale well drilling operations are required to use "reduced emissions" or "green completion" equipment to capture gas and condensate that comes up with hydraulic fracturing flowback, preventing their release into the air and making the valuable hydrocarbons available to the producer for sale. During a transition period that was scheduled to end on January 1, 2015, producers had the option to flare, although green well completions are preferred for multiple reasons.

- They provide the same reduction in Volatile organic compounds (VOCs) as flaring. But while flaring allows the emission of smog-forming nitrogen oxides, green well completions do not.
- By capturing a valuable resource rather than wasting it, green well completions make that resource available for sale or use by the producing company. According to the EPA, green well completions were already used on about 50 percent of wells at the time the draft rule was issued.

EPA estimates the total annualized engineering costs of the final NSPS will be $170 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the final NSPS are estimated to be -$15 million, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf) and condensate price of $70/barrel (measured in 2008 dollars).[32] Industry sources also report a reduction in the cost of gas associated with green completions. In this respect, the WRI authors went on to conclude: "Fortunately, most strategies for reducing venting and leaks from U.S. natural gas systems are cost-effective, with payback periods of three years or less." (Bradbury et al, 2013).

In summary, recent EIA Annual Energy Outlooks take into consideration the relevant regulatory and other structural components needed to forecast avoided costs of gas in New England. In particular, the TCR team is unaware of any credible research or analysis published subsequent to AESC 2013 that supports its assumption that AEO forecasts are not accurately reflecting the cost of compliance with environmental and greenhouse gas regulations governing shale gas production. On the contrary, the EPA has projected positive economics associated with its requirement for green completions as a means of controlling and reducing GHG emissions from shale gas well drilling operations. In addition, actual gas production experience in 2013 and 2014 has been dispositive in this regard.

2.7 Uncertainty and Risk in Projecting Wholesale Gas Market Prices

As noted earlier, the major factors driving gas demand and supply, and hence wholesale gas market prices, include:

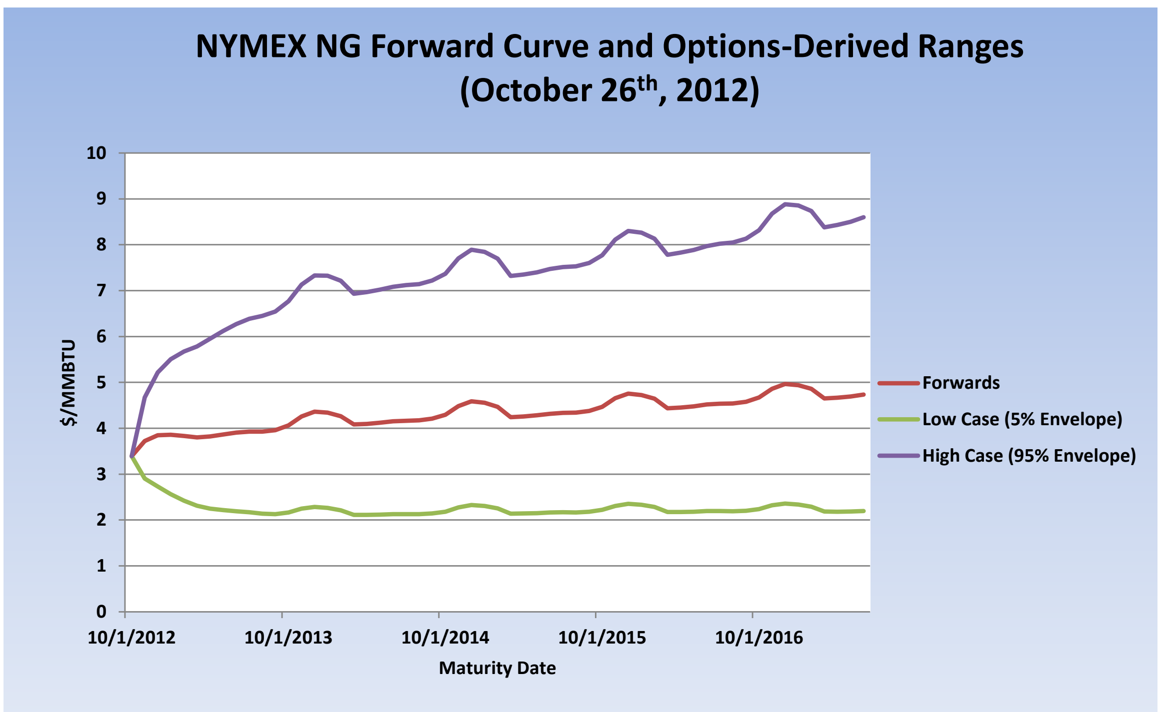
- Gas resources, reserves, production and the technologies that underlie each of these
- The availability of gas transportation via two million miles of gas pipelines and distribution mains in North America
- Regional, national and, increasingly, international economic activity
- Advances in technologies for gas production, transportation and use, e.g., notably in the past decade, respectively, horizontal drilling, advanced LNG systems, and high-efficiency gas-fired electricity generation using combined-cycle combustion turbines (CCGTs)
- Price elasticity of natural gas in each use and cross-elasticity with oil, electricity and other competing fuels
- Infrastructure expansion, including pipeline and storage capacity

[32] U.S. Environmental Protection Agency, Regulatory Impact Analysis, Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry., Office of Air and Radiation, Office of Air Quality Planning and Standards, April 2012.

Variations in forecasts based upon those assumptions is inevitable due to the uncertainty associated with projecting future values of those driving factors.

Sensitivity analyses around the range of natural gas commodity economics is the best way to assess risks inherent in the forecast, and will be included in the AESC 2015 report. Stibolt (Galway Group, 2012) and other analysts comment widely on the risks in forecasting gas market prices, observing that the 90% confidence interval may be as high as the range of $3 to $8 per MMBtu.[33] While these levels of risk are prevalent in most energy forecasts over the past few decades, AESC 2015 captures the uncertainties by choice of High and Low Cases that are more closely articulated to actual market assumptions that the kind of wide range Stibolt (2012) and other have been able to compute from analysis of gas options market prices.

Exhibit 2-20. Range of Implied Risk in Natural Gas Prices



Source: Robert D. Stibolt, "Perspectives on World Natural Gas Markets," Galway Group, L.P., in presentation before the 31st USAEE/IAEE North American Conference, Austin, TX, November 6, 2012.

[33] Robert D. Stibolt, "Perspectives on World Natural Gas Markets," before the IAEE-USAEE Energy Conference, Austin, TX, November 2012. Analysis of implied volatility based on NYMEX natural gas option prices.

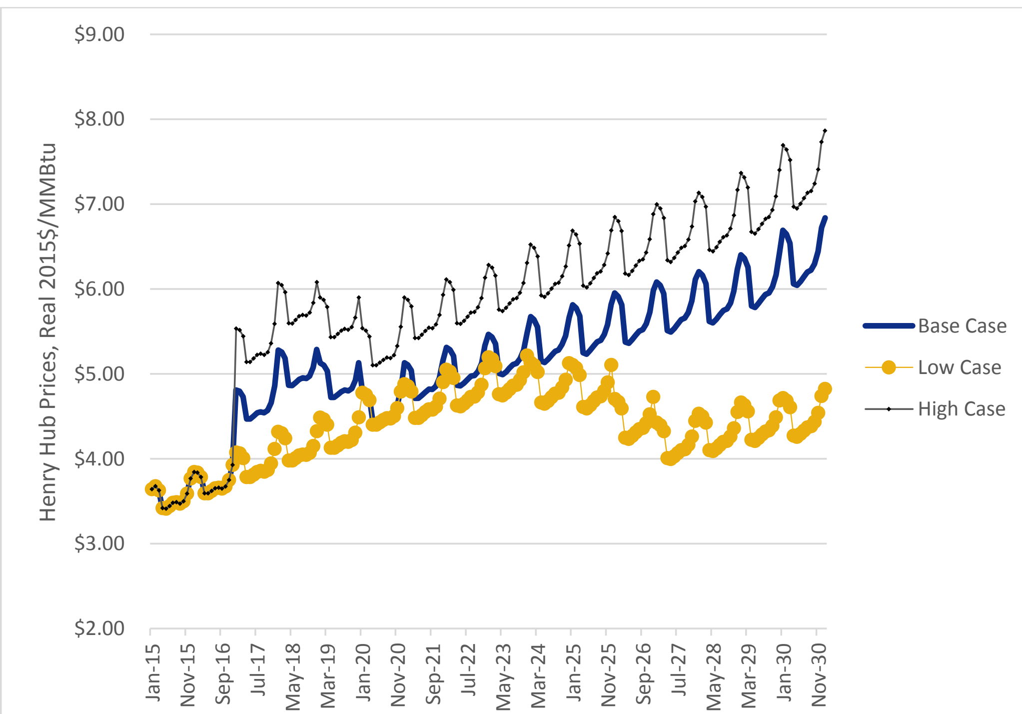
2.8 Gas Price Volatility and/or Uncertainty of Gas Prices

Volatility is a measure of the randomness of variations in prices over time as affected by short-term factors such as extreme temperatures, hurricanes, supply systems disruptions, etc. It is not a measure of the underlying trend in the price over the long-term. AESC 2015 forecasts of natural gas production prices under base, high, and low cases provide projections of expected average natural-gas prices in any month of any year. Actual gas prices are quite volatile and in any future month, week, or day may vary considerably around the expected annual average prices forecast in each of those three cases. Consistent with prior AESC studies, we do not forecast the actual monthly or weekly prices that would reflect historical price volatility primarily because we are forecasting prices used to evaluate avoided costs in the long term.

2.9 AESC 2015 Forecast of Gas Prices Henry Hub

The AESC 2015 forecast of gas prices at Henry Hub for the three cases shown in Exhibit 2-21 was developed as described below.

Exhibit 2-21. AESC 2014 Forecast of Monthly Henry Hub Gas Prices, 2015$/MMBtu



2.9.1 Base Case Forecast of Henry Hub Gas Prices

In developing the AESC 2015 Base Case Henry Hub price forecast, the TCR Team considered a number of available forecasts, as discussed above. The Base Case Henry Hub price forecast relies on the AEO 2014

Reference Case annual Henry Hub price forecast to 2031 and NYMEX monthly Henry Hub futures settlement prices to 2027 at December 18, 2014, as follows:

a. For the months from January 2015 to December 2016, AESC 2015 monthly Henry Hub prices equal NYMEX monthly Henry Hub futures, as above (converted to real 2015$).

b. For the months from January 2017 to January 2031, AESC 2015 equals AEO 2014 Reference Case annual Henry Hub price forecast, converted to real 2015$, and restated to monthly prices.

c. From January 2017 through December 2027, annual AEO 2014 Reference Case Henry Hub prices were converted to monthly prices using monthly variations in NYMEX Henry Hub futures prices throughout.

d. From January 2028 to January 2031, annual AEO 2014 Reference Case Henry Hub prices were converted to monthly prices using monthly variations in NYMEX Henry Hub futures prices during 2027.

e. For all remaining months to December 2045, Henry Hub prices are extrapolated from the above forecast for 2027-2030.

The foregoing procedure resulted in the AESC 2015 Base Case projection of monthly gas prices at Henry Hub from January 2015 through January 2031.

Comparison to other Forecasts of Annual Henry Hub Prices

Exhibit 2-22 compares the AESC 2015 Base Case projections of Henry Hub prices (i.e., the AEO 2014 Reference Case), with NYMEX as of December 18, 2014 and public forecasts from other sources reported in AEO 2014. The AESC 2015 Base Case forecast for 2025 is higher than the NYMEX value and the average of the public forecasts from AEO 2014.

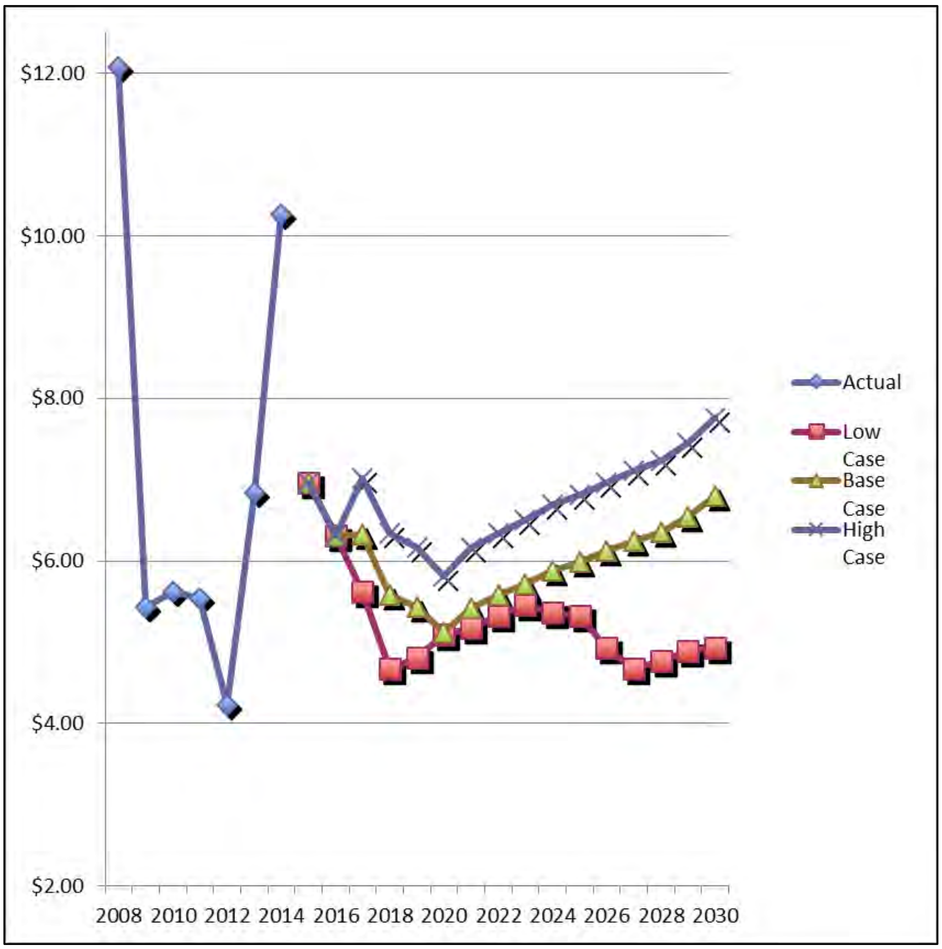
Exhibit 2-22. Comparison of Projections of Annual Henry Hub Prices (2015$/MMBtu)

		Henry Hub $2015/MMBtu		
		2015	**2025**	**2035**
NYMEX	NYMEX 12/18/2014	3.54	4.07	NA
Non-AEO Forecasts	IHSGI	NA	4.12	4.65
	EVA	NA	5.98	6.79
	ICF	NA	5.72	7.24
	BP	NA	0.00	0.00
		0.00	0.00	0.00
	Average Non-AEO Forecast	#DIV/0!	5.27	6.23
AEO	AEO 2014 Reference Case	3.93	5.50	7.27
AESC 2015	AESC 2015 Base Case	3.55	5.50	NA

2.9.2 Low and High Price Case Forecasts of Henry Hub Gas Prices

The AESC 2015 Low and High Cases reflect differing assumptions about the factors driving the national gas supply market. In the High Case, the AEO 2014 Reference Case Henry Hub gas price forecast is increased by 15%; in the Low Case, the AEO 2014 High Oil & Gas Resource (HRC) is substituted altogether for the Reference Case, and converted to monthly prices based on the same variations in NYMEX Henry Hub gas futures prices, as described above. Exhibit 2-23 compares all three AESC 2014 forecasts of avoided gas costs in New England, showing annual average prices.

Exhibit 2-23. AESC 2015 Avoided Gas Cost Forecasts - Base, High and Low Cases for Annual Wholesale Customers on Algonquin (2015$ per MMBtu)



The procedure employed to develop the AESC 2015 High Price Case forecast of monthly Henry Hub gas prices is identical to the foregoing, except we increase each of the forecast Henry Hub prices in the AEO 2014 Reference Case forecast by 15%. This level of increase is based on our judgment. It is less than the average 20% increase under the AEO 2014 Low Oil & Gas Resource Case because we believe the AEO

2014 Reference Case already is, if anything, on the high side. Thus, choosing a 15% increase for the AESC 2015 High Case is, in our judgment, a very high price case.

2.10 Wholesale Gas Costs in New England

AESC 2015 includes a forecast of the avoided wholesale cost of gas in New England based on an analysis of the market fundamentals expected to drive that cost over the study period. In addition to the projected cost of gas at Henry Hub, therefore, those fundamentals include the projected demand for gas in New England for electric generation and for retail end-uses, the projected quantity of imports of gas from Atlantic Canada and of LNG, production in the Marcellus/Utica shale regions, and the projected level of pipeline capacity that will be available to deliver gas from the Marcellus/Utica shales into New England throughout the planning horizon. (The projected demand for gas in New England for electric generation will be driven by numerous factors, including the long run projected price of fuel oil relative to the price of natural gas, and the level of financial penalties ISO-NE may impose on generating units which fail to meet their capacity performance obligations.)

Regional gas pricing in New England, and elsewhere east of the Mississippi is adapting to reflect the increasing role of Marcellus/Utica shale gas production, as described earlier in this chapter. In this section, we review the way wholesale natural gas market mechanisms operate in the U.S. as they affect New England, and then review basic assumptions about how they will function and what factors will drive gas prices going forward through the planning horizon of this report.

In essence, the way the gas market works is that competing suppliers and buyers in New England and elsewhere negotiate and establish gas prices for each day, or for the month ahead, at hubs in spot markets. They take into consideration information about hub prices, geography, service differentiation, weather, pipeline capacity availability, expected electricity and other gas demands, and other factors. As production and demand changes take place, the nexus of gas demand and supply can vary greatly from point to point throughout the gas pipeline grid over days, seasons, and decades. The flexibility and depth of hub-based spot markets has been, and will continue to be a significant enabling factor in the continued development and rise of shale gas production, which is often variable on a day-to-day basis.

In the following sections, we review assumptions about commercial mechanisms, price drivers, and pipeline capacity as they affect future avoided costs of gas to power plants and LDCs.

2.11 Factors Driving Wholesale Avoided Costs in New England

Forecasting avoided gas costs in New England necessarily involves determination of future prices of gas from the marginal source of gas production, pipeline rates to New England gas receipt points and basis to New England pricing points. Our assumptions concerning these elements are discussed in this section.

2.11.1 Pipeline Rates to New England

As discussed above, shippers on Algonquin, TGP and other pipelines pay for gas transportation services according to rate schedules contained in each pipeline's tariff. Pipeline rates are generally set on a cost of service basis and approved by the FERC (by state regulatory commissions and boards in the case of LDCs) following rate proceedings involving shippers and numerous other interested parties. Some pipelines have sought to charge market-based rates to their shippers, i.e., basis, but the FERC has to date not generally approved such formulations.

Rates paid for pipeline transportation services depend on the class of shipper:

- Firm shippers pay demand charges that are fixed, effectively pipeline capacity reservation charges, plus commodity and fuel charges that are variable, i.e., vary with the volume of gas that is shipped. Under current rate design principles, fixed charges recover nearly all the pipelines' costs of service.
- Non-firm (interruptible, general, and numerous other categories) pay variable charges only, although such rates are also designed to recover costs (i.e., they are greater than the variable charges paid by firm shippers).

Firm shippers on New England's gas pipelines include LDCs, and some electric power plants and gas marketing companies.

As in prior years' AESC reports, the AESC 2015 forecast assumes power plants bid into the New England pool based on the spot market value of gas, i.e., on the local spot price. During winter months, therefore, spot prices in New England are historically quite high as demand for house heating is at its highest and available pipeline capacity must be supplemented with gas in storage in the form of liquefied natural gas (LNG), with imported LNG, and propane-air, as discussed in earlier sections of this report. During other months, when pipeline capacity is available, high-cost LNG is not needed, demand is relatively low, and prices fall to levels just above supply hub prices, i.e., Marcellus/Utica regional hub prices plus pipeline fuel charges (typically only a few percent of supply region prices).

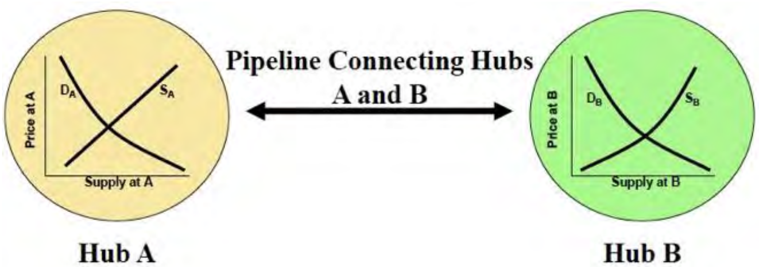
As a result of the foregoing, actual pipeline rates only partly or indirectly drive difference in market prices between gas supply regions and consuming regions. This point is key in New England, and is elaborated on below.

2.11.2 Gas Price Basis Differentials to New England

As discussed in section 3, liquid hubs are defined as those where trading volumes, numbers of participants, choices of supplies and demands, and market depth are all sufficient to establish fair commodity market prices that are set by the forces of supply and demand. Examples in the U.S. gas industry include Henry Hub, Texas Eastern M-3 (Tetco M-3), and many others including, in New England, Algonquin Citygates and Tennessee Zone 6 (Dracut). The defining characteristic of a gas hub (or pricing point) is the immediate or short-term availability of liquid markets, i.e., to the buyers, a number of alternative supplies and suppliers of natural gas, and, to the sellers, a number of alternative demands and buyers of gas. Hence, the forces of supply and demand are able to establish an immediate market clearing price at every point in time, or every day, depending on how much trading is conducted. Conditions for a successfully functioning hub include continual supply-demand imbalances, large and small, and the freedom for parties to transact at will to reconcile these imbalances. Thus, as pointed out above, there is always a buyer for gas supplies, and likewise, there is always a seller of gas – thus market clearing prices are able to establish on an economic basis (i.e., the price that balances supply and demand), even if such prices change from time to time in response to changing supply-demand balances and imbalances, even within a day's trading at major gas hubs.

Gas price basis differentials, sometimes shortened to "basis," refer to the difference between the price of gas at one liquid hub and another, each defined in the foregoing sense. As shown in Exhibit 2-24, illustrative hubs A and B are each liquid pricing points, in other words, the interaction of gas supply and demand at each hub (shown in the diagram as price-quantity curves at each hub) determine clearing prices in spot or short-term markets. This takes place independently of transportation rates on one or another pipeline, even a pipeline that may connect the two hubs.

Exhibit 2-24. Illustration of Basis Differentials in the U.S. Gas Industry



For example, in Exhibit 2-24, Hub A might be Texas Eastern Zone M-3 ("Tetco M-3") and Hub B might be Algonquin Citygates ("AGTCG"), both liquid gas hubs. The Algonquin pipeline's route of transportation connects Lambertville, NJ (within Tetco M-3) with a number of gas utilities in New England, whose receipt points are located at what are known as "city gates" for each LDC, i.e., points where Algonquin delivers gas to the LDC. Even though Algonquin's firm rate is approximately $.23 per MMBtu to transport gas along its length from Lambertville to LDC city gates in New England, that does not force AGTCG versus Tetco M-3 basis to equal $.23 because gas supply and demand are setting the instant price at each point. Sometimes basis is worth more than the pipeline's rate, e.g., in winter peaks, and sometimes it is worth less than the rate, e.g., in mild weather. Indeed, AGTCG-Tetco M-3 basis is rarely exactly (or even close to) Algonquin's filed rate.

It should be noted that most points of gas commerce are <u>not</u> actually located at hubs. For example, the meter of hundreds of gas-fired power plants, thousands of individual apartment complexes and large commercial establishment – these kinds of locations rarely would constitute hubs because they have no physical alternative source of gas supply. All their gas comes from one place, namely, the other side of the meter and typically, from only one vendor – thus none of the above hub-like supply-demand commercial mechanisms described above are possible.

Indeed, whole regions may fall into this category, if they are entirely dependent on the neighboring region for all or most of their gas supply. The entire six-state New England region was for many years in such a situation – all of its gas supplies crossed the New York State or Canadian border; New England was literally at the end of the line (the pipeline). Following completion of pipeline infrastructure from elsewhere – the Iroquois, M&NP, and Portland (PNGTS) pipelines, AGTCG finally became a pricing point, where supply and demand established the price of gas, and whose price became reported in trade press. At that point, New England basis became a relevant commodity – i.e., the price of gas at AGTCG minus, for example, Henry Hub. Until then, gas prices in New England were set by an outside liquid hub, e.g., Henry Hub, Transco Zone 6 New York, or AECO in Alberta, and then buyers would directly add on the pipeline's or pipelines' transportation rates, much as the price of gas supplied to a university or office building in Houston equals the nearby liquid hub price, plus the LDC's distribution rate.

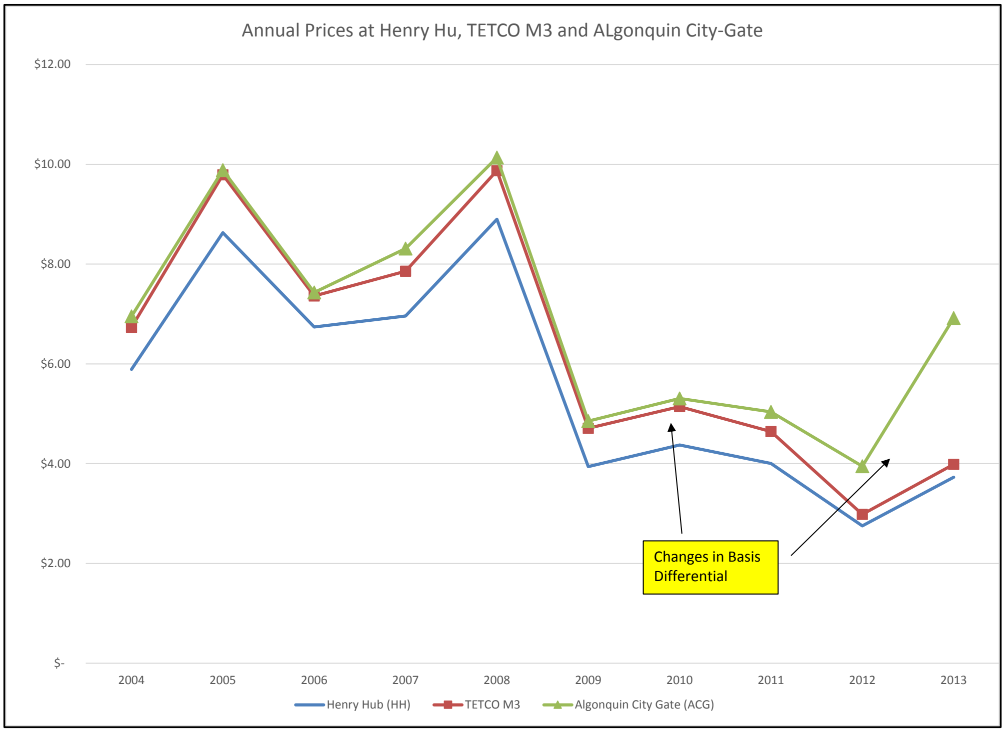
The point is that sometimes and for some buyers in New England, New England basis sets the price of gas locally, and sometimes it does not – therefore, basis is important to understand and forecast, as well as pipeline rates.

More recently, a major question in forecasting gas markets in New England is: relative to which hub, representing which producing region, should basis in New England be measured? We expect production from Marcellus/Utica will drive gas supply costs in New England, but it is not clear which Marcellus/Utica hub will be most prominent in setting gas prices in New England. There are presently several gas hubs and pricing points in the Marcellus/Utica region, including Tetco M-3, which is highly liquid, as well as Leidy (on the Transco Pipeline), Dominion South Point, and others. Only a thorough study of liquidity, outside the scope of this report, and time, will determine if another hub as prominent as Henry Hub is likely to emerge, and which one it will be.[34]

The change in basis between average annual wholesale prices in New England, the Marcellus/Utica area, and Henry Hub over the past 10 years is illustrated in **Exhibit** 2-25. Wholesale prices in New England are represented by the Algonquin city-gate in the exhibit, while the annual average price of gas from the Marcellus/Utica shale region is represented by the Tetco M-3 hub. From 2004 through 2010, basis between New England and Henry Hub and Tetco M-3 and Henry Hub were each quite stable, at approximately $0.88 and $1.08 on average respectively. Since 2011 prices those basis differentials have changed, with Tetco M-3 prices declining more than Henry Hub prices and prices in New England increasing.

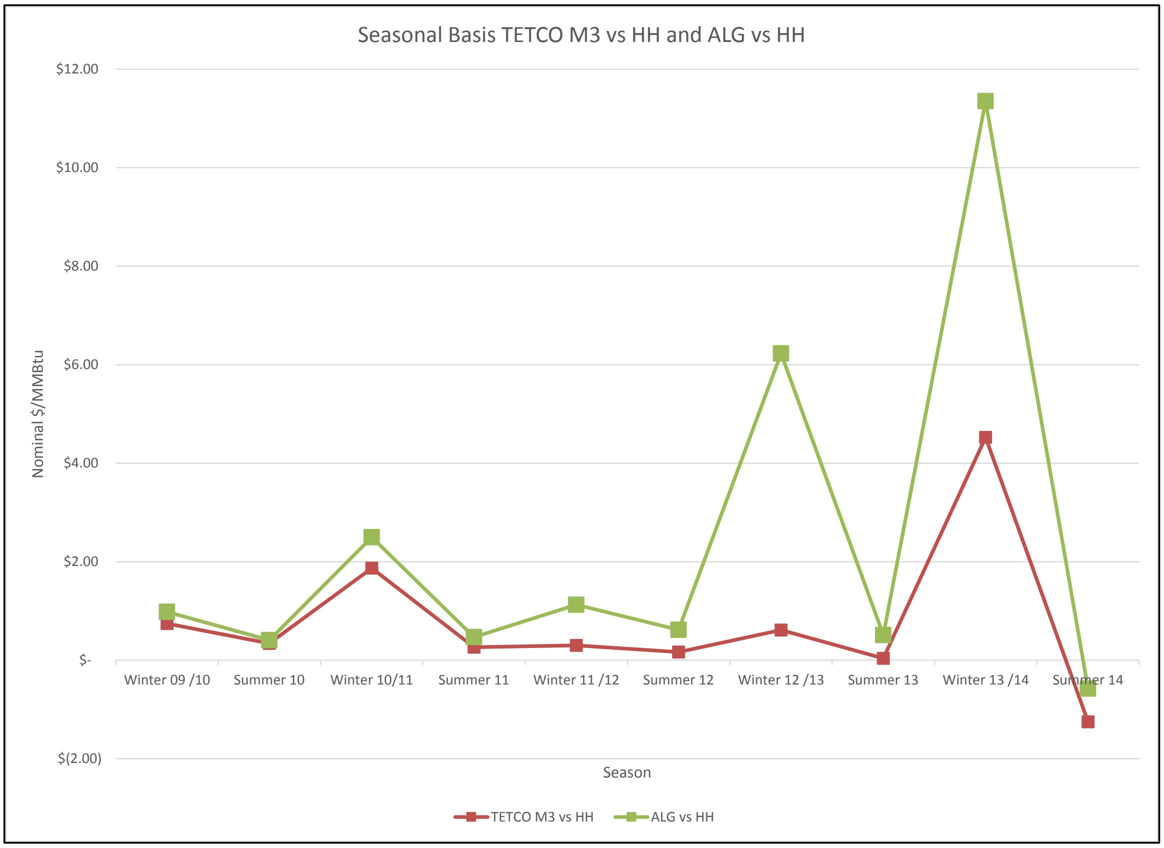
[34] Henry Hub was largely unheard of outside the local industry, and gas prices there were neither surveyed nor reported by gas trade press until 1989, just after NYMEX announced in its CFTC filing that Henry Hub was selected as the point of physical deliveries in its forthcoming gas futures contract.

Exhibit 2-25. Annual Average Prices, Henry Hub, TETCO M3 and Algonquin City Gate, 2004 – 2013 ($/MMBtu)



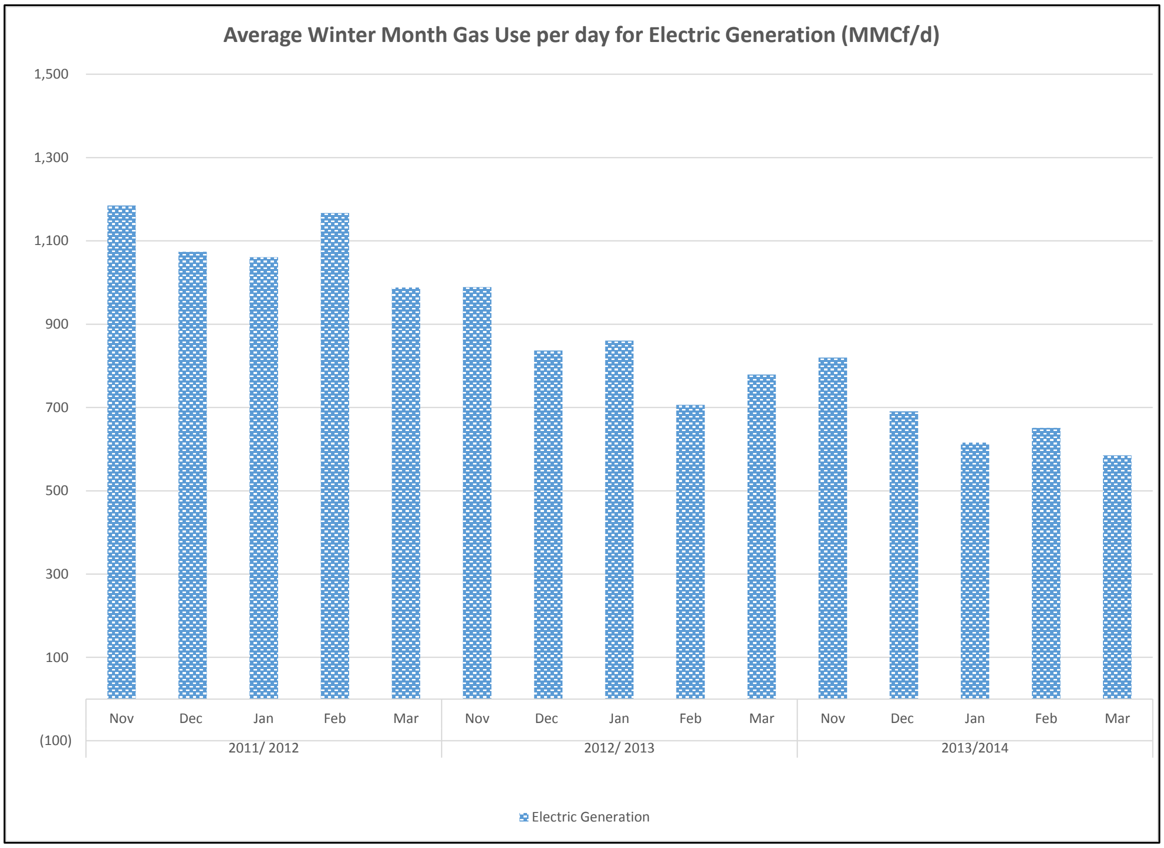
These recent changes in basis are more evident, and dramatic, when viewed by season. Those differentials, plotted in Exhibit 2-26, illustrate the “basis blowouts” which New England experienced in the winters of 2012/2013 and 2013/2014.

Exhibit 2-26. Seasonal Basis to HH



The "basis blowouts" which New England experienced in the winters of 2012/2013 and 2013/2014 do not appear to be caused by a dramatic increase in gas use for electric generation in those two winters relative to prior winters. As indicated in Exhibit 2-27, gas use for electric generation in the winter months of November through March in those two winters was less than in the winter of 2011/2012, when there was no basis blow out. Instead, as discussed earlier, the basis blowout in the past two winters appears to have been driven by the sharp decline in gas deliveries into eastern New England and the corresponding dramatic increase in the supply that had to be delivered into western New England from Marcellus/Utica and other producing areas west of New England.

Exhibit 2-27. Average Gas Use per Day for Electric Generation in Winter Months (MMcf/day)



2.12 Pipeline Capacity Delivering Gas to, and in, New England

One of the major factors driving the basis differential between wholesale gas prices at market hubs in New England and the Marcellus/Utica is the lack of adequate pipeline capacity to deliver gas from producing areas into New England in winter months. In order to develop the AESC 2015 forecast of basis in New England over the study period, we reviewed the projects proposing to add pipeline capacity between the Marcellus/Utica region and New England, as well as to add pipeline capacity within New England.

At the present time, there are five gas pipeline systems that deliver gas into New England. These are listed in Exhibit 2-28 together with their firm contracted capacities serving New England.

Exhibit 2-28. Existing Gas Pipelines in New England, November 2014

Pipeline System	Firm Contracted Capacity Serving New England (Bcf/d)	Enters New England From:	Major Upstream Gas Supplies
Pipelines primarily receiving gas in western New England			
Algonquin	1.1	New York State	Marcellus/Utica
Kinder Morgan/Tennessee (TGP)	1.3	New York State	Marcellus/Utica, U.S. Southeast
Iroquois Gas Transmission	0.2	New York State	Western Canadian Sedimentary Basin (WCSB), Marcellus/Utica
Sub-total	**2.6**		
Pipelines primarily receiving gas in eastern New England			
Maritime & Northeast Pipeline (M&NP)	0.9	New Brunswick, Canada	Sable Island, Canaport LNG import terminal
Portland Natural Gas Transmission System (PNGTS)	0.2	Quebec (P.Q.), Canada	Western Canadian Sedimentary Basin (WCSB); Marcellus/Utica
Sub-total	**1.1**		
Total	**3.7**		

Source: ICF, "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II"," ISO New England, December 16, 2013, Exhibit 2-3, pg. 12.

The total capacity of the existing gas pipelines serving New England is approximately 3.7 Bcf/day, as seen in Exhibit 2-28. (Note that this total does not include the aggregate 2.2 Bcf/d capacity of the Distrigas LNG terminal plus gas utility peak shaving facilities.[35]). Of that total, approximately 2.6 Bcf/day of pipeline capacity is available to deliver gas received from west of New England. In contrast, maximum average gas use per day in January and February for both residential, commercial and industrial load and electric generation has been approximately 3.3 Bcf/day. Thus, if the region wanted the ability to acquire all of its maximum winter month average daily supply from west of New England, it would need another 0.5 Bcf/day of capacity delivering into western New England. (Note emphasis, because maximum gas use per day is much higher when based on gas utility "design day" requirements and electric industry peak winter day demand.) [36]

2.12.1 Proposed Gas Pipeline Expansions in New England

Numerous pipeline capacity expansions have been proposed to deliver added gas supplies to LDCs and power plants in New England. These are listed in Exhibit 2-29. The total pipeline infrastructure that would be added in New England for all of these proposed projects, if completed, would be within the range of 2.3 Bcf/day to 5.4 Bcf/day.

[35] ICF, "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II"," ISO New England, December 16, 2013, Exhibit 2-3, pg. 12.

[36] Ibid., Exhibit 2-5, page 14

Exhibit 2-29. Proposed Gas Pipeline Capacity Expansions To, and Within, New England

Pipelines primarily receiving gas in western New England				
Project	**Capacity, Bcf/day**	**Planned in-service**	**Status as of December 2014**	**Shippers**
Tennessee – Connecticut Expansion	0.072	16-Nov	Precedent Agreements executed; FERC filing anticipated by EOY 2014.	Connecticut Natural Gas; Southern Connecticut Gas, Yankee Gas
Algonquin Incremental Market ("AIM")	0.342	16-Nov	FERC Filing in February 2014; Draft EIA issued on 8/8/14.	LDC affiliates of UIL, NU, National Grid, Nisource; Cities of Norwich and Middleborough, MA
PNGTS – Continent-to-Coast ("C2C")	0.165	16-Nov	Open Season closed 1/2014, since extended due to uncertainty over availability of upstream capacity.	None announced to date
Spectra – Atlantic Bridge	0.100 to 0.600	17-Nov	In negotiations	Unitil Corp.
Spectra & Northern Utilities – Access Northeast	1	18-Nov	Announced 9/14. Solicitation of interest held fall 2014	None announced to date
Kinder Morgan/Tennessee – Northeast Energy Direct	0.600 to 2.200	18-Nov	Precedent Agreements executed for 0.5 Bcf/day, others In negotiation; Pre-Filed to the FERC in July 2014.	Various New England LDCs (approx. 500 MMcf/day as of 11/2014)

Source: New England Gas Association (NEGA, November 2014).

In addition to the projects listed in Exhibit 2-29, and in some cases to support their operations, gas pipeline capacity upstream (to the west) of New England must be increased (NEGA, 2014). For example, Cabot Oil & Gas and Williams are developing the 120-mile Constitution Pipeline, to extend from Susquehanna County, PA, to the IGTS and TGP systems in Schoharie County, N.Y. The sponsors of that pipeline plan to have it in operation for the 2015-2016 winter (proposed capacity is 650 MMcf/day, and Cabot and Southwestern Energy are announced shippers). The Constitution Pipeline could help serve gas demands in New England, New York, and Central Canada. This and other proposed "upstream" pipeline projects are listed in Exhibit 2-30.

Exhibit 2-30. Proposed New Pipeline Capacity Upstream of New England

Project	Capacity, Bcf/day	Planned in-service	Status as of December 2014	Shippers
Cabot/Williams Constitution Pipeline	0.65	Late 2015	Authorized by FERC 12/2/14	Extend from Susquehanna County, PA to the Iroquois Gas and Tennessee Gas pipeline systems in Schoharie, N.Y.
Iroquois Gas - Wright Interconnect Project (WIP)	0.65	2015	Authorized by FERC 12/2/14	Enable delivery of 0.65Bcf/d from Constitution Pipeline into Iroquois and Tennessee.
Tennessee - Niagara Expansion	0.158	Nov. 2015	Filed with FERC Feb. 2014	Designed to provide transportation from Marcellus Shale to TGP's interconnect with TCPL in Niagara, N.Y.
Iroquois Gas - South-to-North Project	0.3	Nov. 2016	Open season Dec. 2013 – Jan. 2014	Reverse flow on Iroquois from Iroquois' existing interconnects with Dominion Transmission in Canajoharie, NY and Algonquin Gas Transmission in Brookfield, CT, as well as the proposed Constitution Pipeline in Wright, NY.

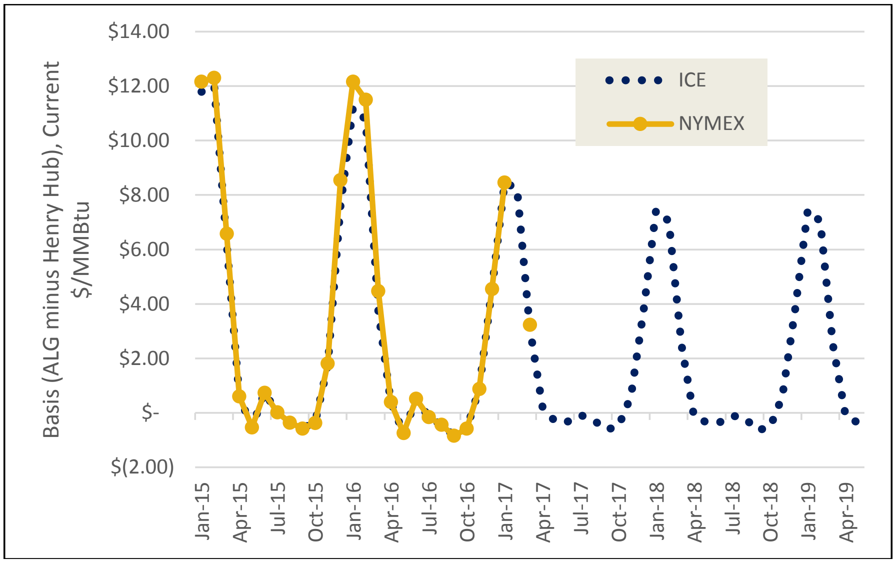
2.12.2 Projection of Basis Differentials to New England.

AESC 2015 projected the basis between Algonquin Citygates and Henry Hub ("ALG HH basis") using different methods for three different segments of the study period. Those three segments are January 2015 through October 2017, November 2017 through October 2019, and November 2019 onward.

January 2015 through October 2017

AESC 2015 projected ALG-HH basis through October 17 based on an average of NYMEX and ICE basis futures as of December 15, 2014 presented in Exhibit 2-31. Small differences between settlement prices for ALG-HH basis on each exchange indicate some liquidity exists in these contracts. The marked rise in ALG-HH basis futures during winter months is consistent with past behavior, but not necessarily a valid forecast. AESC 2015 relied on these futures for the near-term months when trading volumes are the highest. Basis futures, like any futures, represent the market for a commodity (ALG-HH basis in this case), i.e., the nexus of traders' views on this value. The decrease in winter basis spikes (less intensive "blow-outs" starting Winter 2016-2017) suggests that the market is anticipating some degree of future gas pipeline construction into the New England region. For hub pricing purposes, deliveries to PNGTS and Vermont Gas are equated to TGP based on current market directions.

Exhibit 2-31. Algonquin Citygates Basis Futures, ICE and NYMEX, $/MMBtu Relative to Henry Hub



November 2017 through October 2019

AESC 2015 basis projections for the period November 2017 through October 2019 assume that additional pipeline capacity will be added to serve the New England market in November 2017 and November 2018 respectively:[37] The assumed capacity additions are the Tennessee-Connecticut Expansion, the Algonquin Incremental Market (AIM) expansion, and the portion of the Kinder Morgan/Tennessee Northeast Energy Direct expansion to which LDCs have agreed to subscribe and are likely to subscribe, in our judgment. Thus, AESC 2015 anticipates that proposed pipeline expansions for which shippers have entered into binding precedent agreements will be built, plus about 10 percent. In all, as indicated in Exhibit 2-32, AESC 2015 assumes that approximately 1 Bcf/day of new pipeline capacity will enter service in New England during this period.

[37] *Source: Exhibit 4-6 in Task 2A Gas Assumptions, 12-15-2014 v2).*

Exhibit 2-32. Anticipated Gas Pipeline Capacity Expansions to New England

Project	Capacity, MMcf/day	Rationale
Tennessee-Connecticut Expansion	72	Subscribed.
Algonquin Incremental Market (AIM)	342	Subscribed.
Kinder Morgan/Tennessee – Northeast Energy Direct	600	500,000 MMBtu per day of the offered capacity range has been subscribed; an additional volume of at least 100,000 MMBtu per day of subscription is anticipated.
Other capacity		As economical (see below)
Total	Approx. 1,000	Approx. total subscribed.

AESC 2015 projects that the addition of approximately 1 Bcf/day of pipeline capacity will reduce New England basis in peak months significantly, indeed, to 30% below the ALG-HH basis levels anticipated by traders as reflected in futures prices for this period, as of December 14, 2014 (which were shown in Exhibit 2-31).

After November 2017, when we assume the AIM and Tennessee Connecticut Expansion together add 0.4 Bcf/day, AESC 2015 projects a 46% drop in peak month basis relative to the 2016/2017 winter. After November 2018, when we assume the Northeast Energy Direct project or its equivalent adds another 0.6 Bcf/day in November 2018, AESC 2015 projects peak winter month basis to drop by another 44%. These capacity additions are not expected to have nearly as great an impact on basis in off-peak months. In all, AESC 2015 assumes the capacity additions, shown in Exhibit 2-32, will restore New England winter basis to levels more consistent with earlier, pre-blow-out winters.

AESC 2015 projects Tennessee Zone 6 HH basis to be slightly lower than ALG HH basis and Iroquois HH basis to be lower than Tennessee's. These projections are supported by basis data[38] and by the fact that the Tennessee and Iroquois pipelines each receive Marcellus/Utica gas along a more direct and less costly route than the Texas Eastern-Algonquin combination. In addition, Iroquois predominantly serves the more competitive New York Metropolitan area, thus will not sustain the higher basis levels characteristic of Algonquin.

AESC 2015 assumes that gas utilities will use most, if not all, of the additional pipeline capacity available to them to meet load growth on their systems, thereby not increasing the ability of gas fired generators

[38] Platts IFGMR monthly Market Center Spot Gas Prices.

to acquire gas from Marcellus/Utica during winter months. In particular, we reasonably anticipate that, once gas utilities in MA, CT and ME acquire additional capacity they will "build out" their systems in order to grow their load by adding more customers because they have indicated their intent to do so by entering into binding Precedent Agreements for new pipeline capacity.

AESC 2015 is projecting the addition of 1 Bcf/day of pipeline capacity will reduce basis in peak months based on its assumption gas fired generators will be able to use a portion of that additional pipeline capacity for several years. That assumption, in turn, rests upon an assumption that it will take several years before growth in retail gas use will require New England gas utilities to use one hundred percent of their entitlements to this additional capacity. The latter assumption rests on the following high-level comparison of projected average peak winter month demand in New England, excluding VT,[39] and projected capacity able to deliver gas from Marcellus/Utica during winter months. We prepared that comparison based on the following:

An estimate the capacity available to deliver gas from Marcellus into New England each year from 2011 through 2023. This estimate assumes that by 2015 Marcellus Gas will be able to flow into the PNGTS system from TCPL. (See for example, December 2014 report by Navigant for Ontario that discusses increasing supply of Marcellus gas flowing into Ontario and then eastward on the TCPL system). We focus on capacity available to deliver gas from Marcellus into New England because of the dramatic decline in supply from LNG imports to New England and from production from eastern Canada delivered via MN&P.

Compare that estimate to projected load under two different Growth Cases, the AEO 2014 Reference Case forecast for New England and a higher growth case based on public projections from CT[40] and ME respectively.

Calculate average gas use/day by gas utilities and by electric generators in the peak winter months of December, January and February for the winter of 2011/2012. We use 2011/2012 data because those months had close to normal Heating Degree Days per data for the NGRID system.

a. Project average gas use/day by gas utilities and by electric generators in the peak winter months for each of the two load growth cases. The projection assumes average gas use/day in those 3 months growths at the same rate as annual gas use.

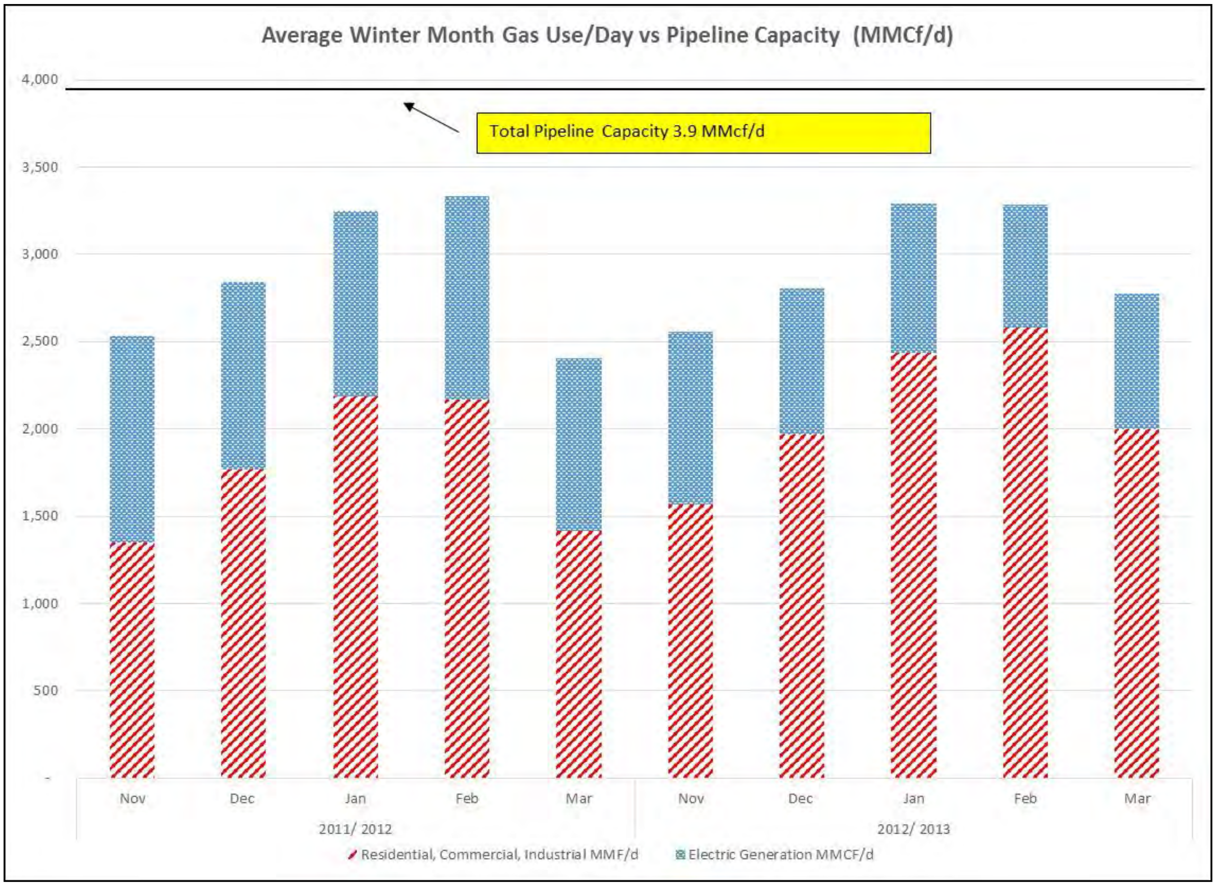
b. Compare the average gas use /day to the estimate of capacity available to deliver gas from Marcellus into New England each year.

[39] VT is excluded because it is not connected to the rest of the New England pipeline grid. It acquires all of its supply via TCPL.

[40] Connecticut's Gas Local Distribution Companies Joint Natural Gas Infrastructure Expansion Plan, June 14, 2013. http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/4539e0715c01bd9a85257b8d005af2a/$FILE/Gas%20Expansion%20Plan%20vFINAL.pdf

As discussed earlier, and indicated in Exhibit 2-33, the spikes in basis in the winter of 2012/2013 was not due to insufficient total pipeline capacity serving New England. Instead, it was due to insufficient pipeline capacity able to deliver gas from west of New England.

Exhibit 2-33. Average Winter Month Gas use per Day vs. Pipeline Capacity



Our comparisons, presented in Exhibit 2-34 and Exhibit 2-35 indicate that under either load growth projection it does not appear that gas utilities will use 100% of the additional new pipeline capacity capable of delivering gas from west of New England on average during the three peak winter months for many years. Instead, it appears that a significant portion of the additional new capacity will be available to deliver gas for electric generation.

Exhibit 2-34. AEO 2014 Reference Case Load Forecast

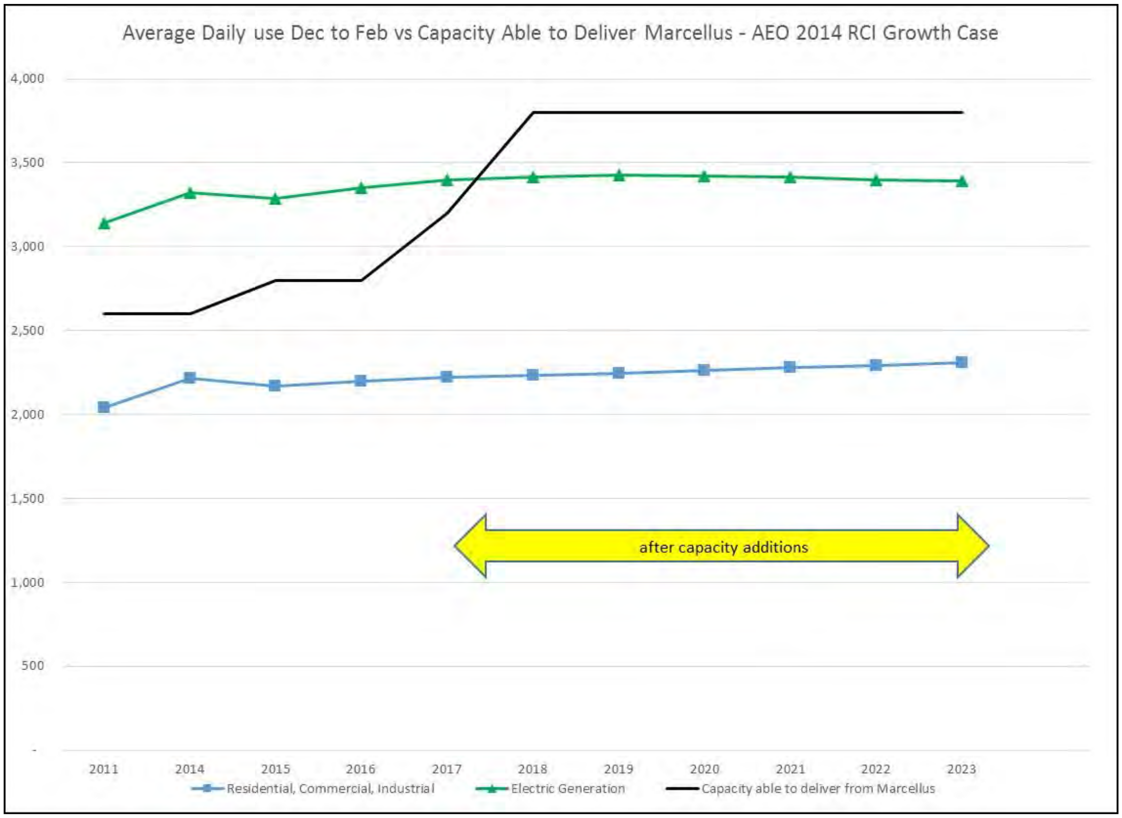
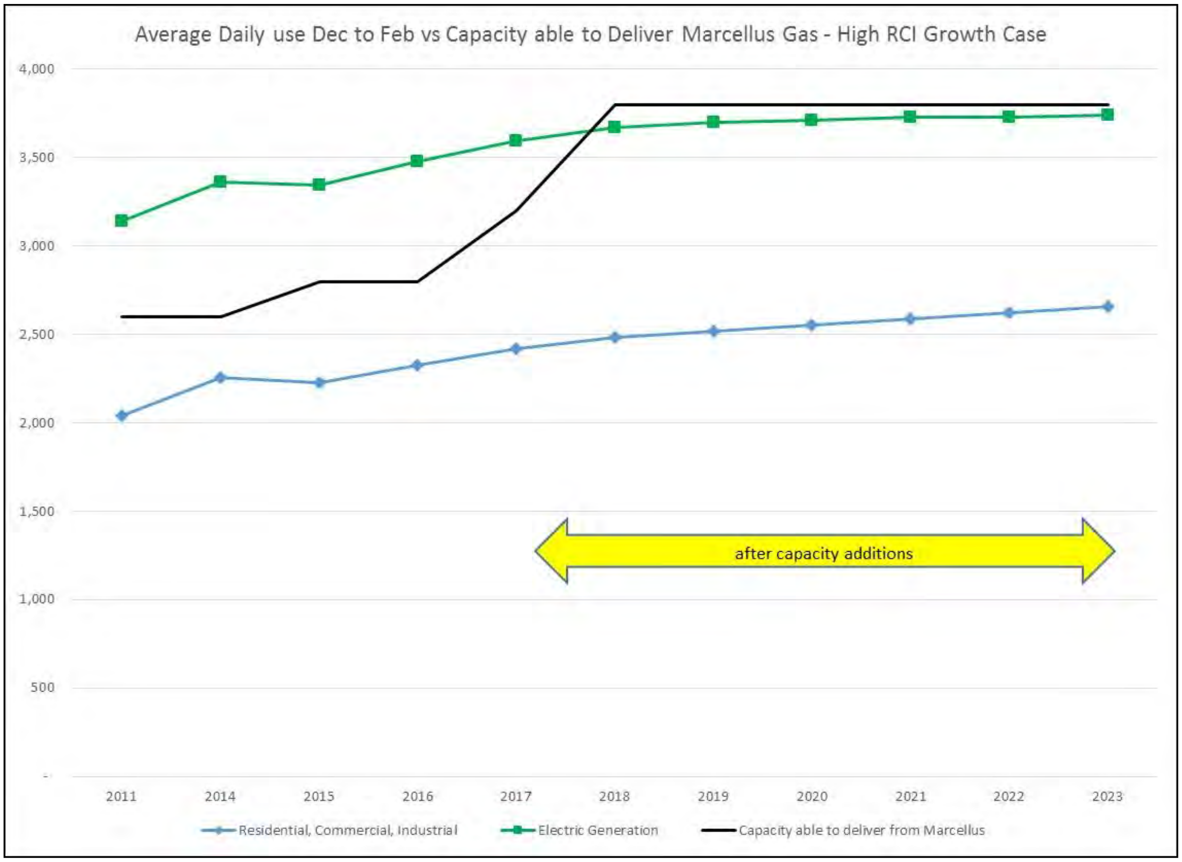


Exhibit 2-35. High Gas Utility Load Forecast



Instead, even with high gas utility load growth, it appears the addition of 1 Bcf/day of capacity by November 2018 would significantly increase the quantity of pipeline capacity available to deliver gas for electric generation on average during the three peak winter months.

It is reasonable to assume that up to 1 Bcf/day of capacity will be added within that timeframe based upon the number of projects competing to add pipeline capacity into New England, as listed in Exhibit 2-29, and the visibly high peak-period gas prices experienced in New England. This assumption is consistent with the discussion of New England market conditions for capacity and supply presented in the CT gas utilities' infrastructure expansion plan, pages 88 to 91.[41]

November 2019 onward

From 2020-2031, ALG, Tennessee and Iroquois HH basis remain at lower levels as above, inflated in nominal dollars in the Base Case to reflect the 0.4% annual average demand increase inherent in the

[41] ibid.

AEO 2014 Reference Case. In other words, real ALG-HH basis and Tennessee Henry Hub basis are both expected to decline in the 2020s because low gas demand, increasing efficiency of peak gas consumption, and increasingly mild weather will all act to prevent – on average – basis blow-outs.

2.13 Avoided Natural Gas Costs by End Use

2.13.1 Introduction and Summary

The avoided cost of gas at a retail customer's meter has two components: (1) the avoided cost of gas delivered to the local distribution company (LDC) and (2) the avoided cost of delivering gas on the LDC system (the "retail margin"). Natural gas avoided costs are presented with and without the retail margin.

AESC 2015 developed avoided natural gas cost estimates for three regions: Southern New England (Connecticut, Rhode Island, and Massachusetts), Northern New England (New Hampshire and Maine), and Vermont. Exhibit 2-36 provides the fifteen year levelized estimates assuming no avoided distribution margin, with comparisons to the corresponding values from AESC 2013. VT requested that AESC 2015 calculate its avoided costs for a different set of costing periods.

Exhibit 2-36. Comparison of Avoided Gas Costs by End-Use Assuming No Avoidable Retail Margin, AESC 2015 vs. AESC 2013 (15-year levelized, 2015$/MMBtu except where indicated as 2013$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	RETAIL END USES
Southern New England (CT, MA, RI)								
AESC 2013 (2013$)	6.08	6.57	6.73	6.60	6.26	6.58	6.44	6.53
AESC 2013 (b)	6.29	6.80	6.97	6.83	6.48	6.81	6.66	6.76
AESC 2015	6.00	6.53	6.70	6.56	6.20	6.54	6.39	6.48
2013 to 2015 change	-5%	-4%	-4%	-4%	-4%	-4%	-4%	-4%
Northern New England (ME, NH)								
AESC 2013 (2013$)	6.03	7.53	8.02	7.62	6.58	7.54	7.12	7.39
AESC 2013 (b)	6.24	7.80	8.30	7.89	6.82	7.81	7.37	7.65
AESC 2015	6.00	7.69	8.25	7.80	6.63	7.71	7.24	7.54
2013 to 2015 change	-4%	-1%	-1%	-1%	-3%	-1%	-2%	-1%

	Design day	Peak Days	Remaining winter	Shoulder / summer
Vermont				
AESC 2013 (2013$)	$ 389.03	$ 20.68	$ 8.68	$ 6.32
AESC 2013 (b)	$ 402.76	$ 21.41	$ 8.98	$ 6.54
AESC 2015	$ 523.08	$ 21.83	$ 7.51	$ 6.19
2013 to 2015 change	30%	2%	-16%	-5%

Factor to convert 2013$ to 2015$ 1.0353

Note: AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.
AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.

This set of AESC 2015 avoided natural gas cost estimates for Southern and Northern New England are generally lower than the AESC 2013 estimates, primarily due to the difference between the AESC 2015 projection of gas prices at Henry Hub and the AESC 2013 projection. The estimates for VT are also generally lower, except for the design day costs, which are higher due to a higher projection of Vermont Gas System (VGS) marginal transmission costs.

Exhibit 2-37 provides the fifteen year levelized estimates assuming some level of avoided distribution margin for Southern and Northern New England, again with comparisons to the corresponding values from AESC 2013. The exhibit does not include a comparison for VT because of its use of different costing periods and different end use load shapes.

Exhibit 2-37. Comparison of Avoided Gas Costs by End-Use Assuming Some Avoidable Retail Margin, AESC 2013 vs. AESC 2011 (15-year levelized, 2013$/MMBtu except where indicated as 2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	RETAIL END USES
Southern New England (CT, MA, RI)								
AESC 2013 (2013$)	6.67	7.17	8.30	8.12	6.88	7.74	7.44	7.80
AESC 2013 (b)	6.91	7.42	8.59	8.41	7.13	8.01	7.70	8.07
AESC 2015	6.62	7.89	8.32	8.13	6.81	7.68	7.37	7.35
2013 to 2015 change	-4%	6%	-3%	-3%	-4%	-4%	-4%	-9%
Northern New England (ME, NH)								
AESC 2013 (2013$)	6.53	8.04	9.35	8.91	7.04	8.40	7.86	8.17
AESC 2013 (b)	6.76	8.32	9.68	9.23	7.29	8.70	8.14	8.46
AESC 2015	6.52	8.86	9.64	9.15	7.11	8.61	8.01	6.88
2013 to 2015 change	-4%	6%	0%	-1%	-3%	-1%	-2%	-19%

Factor to convert 2013$ to 2015$ 1.0353

Note: AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.
AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.

2.13.2 Retail End Use Load Shapes

The shape of the retail gas load has a major impact on the cost of natural gas supplied and thus the avoided natural gas costs. End uses of natural gas at the retail level are distinguished by two major types of end-use, heating related load which is driven by temperature and has a low annual load factor and non-heating load which tends to have a flat shape and hence a relatively high load factor. AESC 2015 bases its analyses on a representative utility with a heating load accounting for 70 percent of its total annual load and a non-heating load accounting for the remaining 30 percent. (Residential sector water heating has a load shape that is approximately 75 percent temperature related and 25 percent non-temperature related.

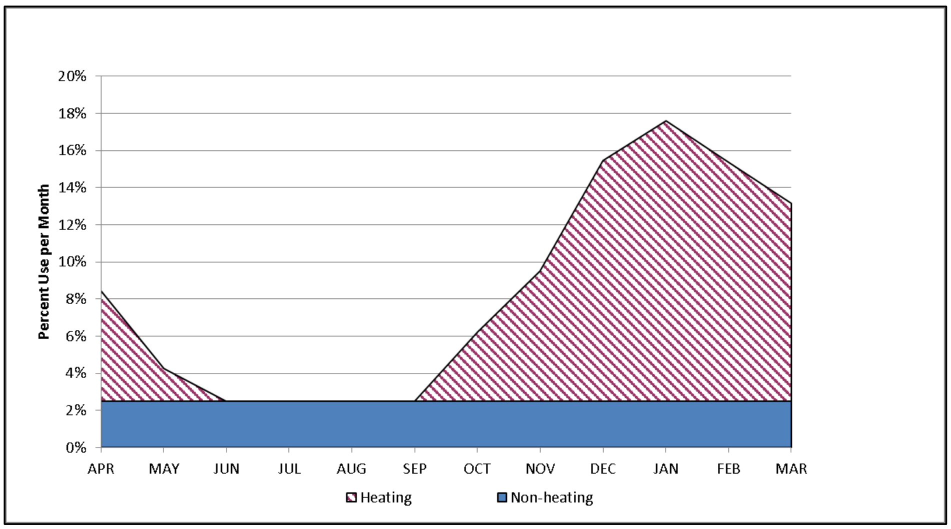
The level of gas use by month for each major type of end-use is shown in table and chart form below. Exhibit 2-38 shows the percentage of annual load in each month for heating and non-heating loads respectively. Exhibit 2-39 plots those loads by month. (This load data is from data provided by National Grid (MA) for AESC 2011 and is consistent with load data Study Group utilities provided for AESC 2015. It will be updated as necessary based on data utilities provide for AESC 2015.)

Exhibit 2-38. Percentage of Annual Load in Each Month for Heating and Non-Heating Loads

Load Type		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Non-Heating	(a)	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.34%	8.34%	8.34%	8.34%	8.33%
	30%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Heating	(b)	8.50%	2.50%	0.00%	0.00%	0.00%	0.00%	5.30%	10.00%	18.50%	21.60%	18.40%	15.20%
	70%	5.95%	1.75%	0.00%	0.00%	0.00%	0.00%	3.71%	7.00%	12.95%	15.12%	12.88%	10.64%
Heating + Non-heating	(c)	8.45%	4.25%	2.50%	2.50%	2.50%	2.50%	6.21%	9.50%	15.45%	17.62%	15.38%	13.14%

(a) Constant load all year; rounding altered in the winter months to maintain 100% use for the year.
(b) Distribution of the heating (low load factor) load among the months of the year based on data provided by National Grid (MA).
(c) Weighted average for each month at 70% heating load shape and 30% non-heating load shape.

Exhibit 2-39. Chart of Annual Load in Each month for Heating and Non-Heating Loads

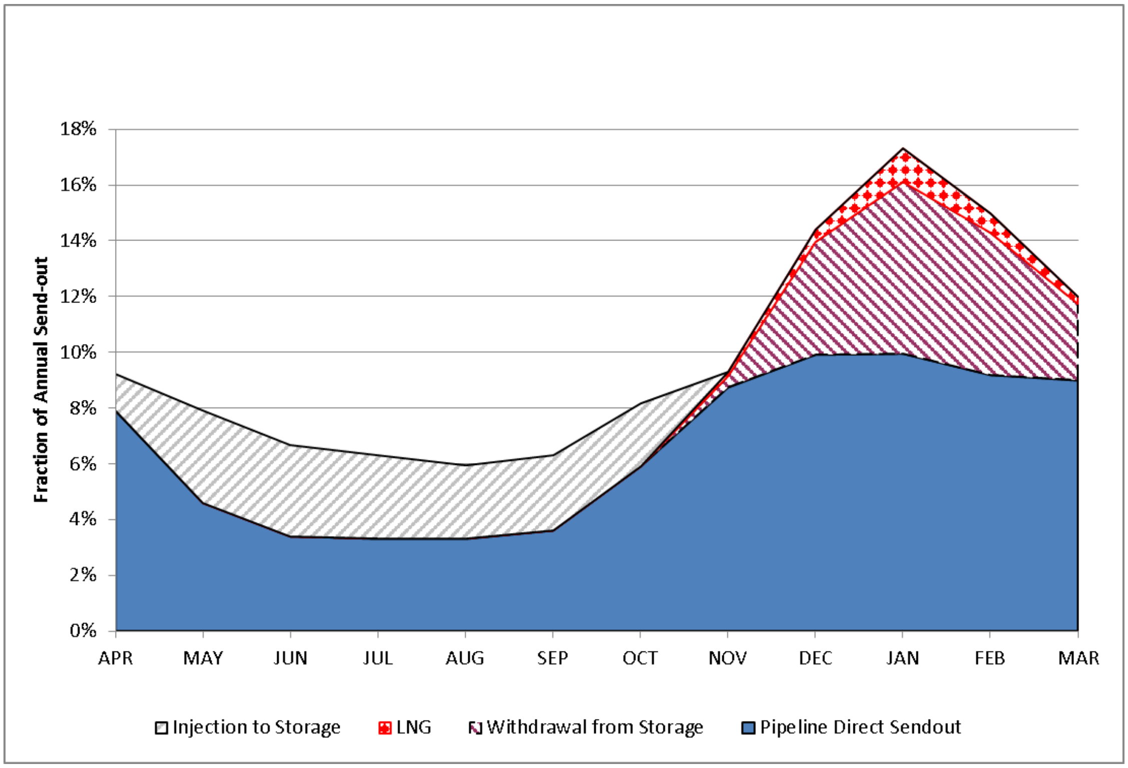


Because of the size of the gas load during the winter (defined as November through March in the gas industry) relative to the summer, and because the variation in daily load during winter months due to variation in daily temperatures, LDCs develop a portfolio of supplies in order to provide reliable service at reasonable cost over time. These portfolios comprise three major categories of delivery and storage resources: long-haul pipeline transportation, underground storage, and LNG or propane facilities. AESC 2015 calculates the avoided cost of gas delivered into the distribution system of a representative New England local distribution company from the avoided cost of each resource in each month and the relative quantity of each resource that an LDC uses in each month.

As illustrated in Exhibit 2-40, LDCs use their long-haul pipeline transportation to supply load directly in each month of the year. In addition, in summer months LDCs use a portion of that pipeline transportation capacity to deliver gas from producing areas for injection into underground storage, and sometimes for liquefaction and injection into LNG tanks. In winter months LDCs meet customer load with gas delivered by pipeline directly from producing areas and from underground storage.

LDCs use gas from LNG and propane facilities delivered directly into their distribution systems to meet daily peaking and seasonal requirements during the months of heaviest load, mostly December through February.[42]

Exhibit 2-40. Sendout from Resources by Month.



2.13.3 Avoided Costs of Representative Gas Supply Resources

New England LDCs use three basic supply resources to meet the requirements of their customers. These resources are (1) gas delivered directly from producing areas via long-haul pipelines, (2) gas withdrawn from underground storage facilities (most of which are located in Pennsylvania) and delivered by pipeline, and (3) gas stored as liquefied natural gas and/or propane in tanks located in the LDC service territories throughout New England.

Except for Vermont AESC 2015 used a representative New England LDC to determine the fraction of customer requirements met from each resource each month and the fraction of storage refill in each of

[42] The data underlying the representative LDC sendout by source is data from LDCs used in AESC 2011. It will be updated as necessary based on data utilities provide for AESC 2015.

the summer months, April through October. Vermont has only one LDC, VGS, and a somewhat different supply mix. AESC 2015 calculates the avoided costs for VGS in a separate section using the characteristics of VGS.

Our analysis assumes that LDCs have optimized the mix of supply sources and thus long-term energy efficiency. The characteristics of a representative New England LDC we use in our analysis are shown in Exhibit 2-41 below. That exhibit presents the numerical data presented earlier in Exhibit 2-40 as a graphical representation.

Exhibit 2-41. Sendout Characteristics of Representative LDC

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual
Fractions of LDC Send-out by Source Each Month													
Pipeline Deliveries, Long-haul	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	93.9%	68.8%	57.5%	61.2%	74.9%	78.8%
Underground Storage	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%	28.2%	35.6%	34.0%	23.0%	18.5%
LNG & Propane Peaking	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	3.0%	6.9%	4.8%	2.1%	2.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fraction of Annual Sendout each Month	7.9%	4.6%	3.4%	3.3%	3.3%	3.6%	5.9%	9.3%	14.4%	17.3%	15.0%	12.0%	100.0%
Monthly Sendout as a Fraction of Peak Month	45.7%	26.6%	19.7%	19.1%	19.1%	20.8%	34.1%	53.8%	83.2%	100.0%	86.7%	69.4%	
Fraction of Underground Storage Injection by Month	7.1%	17.9%	17.6%	16.2%	14.3%	14.6%	12.3%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%

For each gas supply resource we identify the costs of acquiring the resource and the cost of delivering that resource to the LDC.

- For long-haul pipeline deliveries the cost components are: (a) gas purchase costs, (b) the FT service demand rate, and (c) the variable transportation cost. The variable transportation cost includes the variable transportation commodity rate charged by the pipeline, and the cost of gas retained by the pipeline for compressor fuel use and “lost and unaccounted for” gas.

- For deliveries from off-system underground storage resources, which include firm transportation service from the storage to the LDC, the cost components are: (a) the cost of gas purchased for injection, (b) the fixed storage and transportation service charges, and (c) the variable storage and transportation service charges, which includes the storage and transportation fuel costs.

- For on-system peaking resources, we assume there is only a variable cost component. In the case of LNG peaking, which is the predominant type of on-system peaking for LDCs in Southern New England and Northern New England, the variable cost is the purchased gas cost and the cost of gas consumed for liquefaction and vaporization. For propane-based peaking, which is the only type of on-system peaking in Vermont, the variable cost is assumed to be the propane price.

Gas Purchase Cost and Resource Service Cost Assumptions

For this avoided-cost analysis we assume that the marginal gas purchase cost is the monthly price of gas at the Henry Hub. We draw those from our forecast of monthly Henry Hub prices.

As in AESC 2013, we assume that the marginal source of gas to New England LDCs from the Henry Hub is transportation and storage on either of the Tennessee Gas Pipeline (TGP), for LDCs in Northern and Central New England, or the route of Texas Eastern Transmission (TETCO) and Algonquin Gas Transmission (AGT), for LDCs in Southern New England. AESC 2015 developed its projected costs of marginal supply resources for Southern and Northern New England by updating the AESC 2013 projections to reflect the AESC 2015 forecast of Henry Hub prices.

AESC 2015 developed its projected costs of marginal supply resources for Vermont in consultation with staff of VGS. AESC 2015 identified, and developed the marginal costs for, four resources corresponding to the VGS supply resources and the four Vermont four costing periods. The four resources are baseload supply from Dawn via TCPL, storage withdrawals from Dawn storage via TCPL, propane peak shaving and new pipeline capacity, both upstream of and on VGS. Exhibit 2-42 shows the projected costs by year for each of those resources.

Exhibit 2-42. Projected Costs of Marginal Gas Supply Resources in Vermont (2015$/MMBtu)

VT	Delivered Cost of Marginal Resource (2015$ per MMBtu)			
	Baseload (Summer and Winter)	80-Day	10-Day	Peak Day
Marginal resource	Dawn via TCPL	MI / Dawn Storage via TCPL	LP Peakshaving	Marginal Transmission (Upstream + Downstream) + Winter Baseload
Days	275	80	9	1
	a	b	c	d
2015	$ 4.55	$ 6.65	$ 15.66	$ 521.44
2016	$ 4.76	$ 7.03	$ 16.65	$ 521.65
2017	$ 5.65	$ 7.92	$ 18.45	$ 522.54
2018	$ 5.52	$ 7.72	$ 19.70	$ 522.41
2019	$ 5.95	$ 8.31	$ 20.19	$ 522.84
2020	$ 5.60	$ 7.91	$ 20.70	$ 522.49
2021	$ 5.94	$ 8.34	$ 21.24	$ 522.83
2022	$ 6.09	$ 8.46	$ 21.79	$ 522.98
2023	$ 6.21	$ 8.56	$ 22.37	$ 523.10
2024	$ 6.41	$ 8.80	$ 22.91	$ 523.30
2025	$ 6.51	$ 8.91	$ 23.41	$ 523.40
2026	$ 6.67	$ 9.08	$ 23.84	$ 523.56
2027	$ 6.78	$ 9.18	$ 24.37	$ 523.67
2028	$ 6.89	$ 9.30	$ 24.80	$ 523.78
2029	$ 7.08	$ 9.49	$ 25.24	$ 523.97
2030	$ 7.35	$ 9.76	$ 25.60	$ 524.24
15yr Level	$ 6.16	$ 8.51	$ 21.83	$ 523.05

2.14 Avoided Distribution Cost by Sector

The avoided cost for each end-use by sector is the sum of the avoided cost of the gas sent out by the LDC and the avoidable distribution cost, called the avoidable LDC margin, applicable from the citygate to the burner tip.

Estimates of the portion or amount of distribution cost that is avoidable due to reductions in gas use from efficiency measures vary by LDC. Some LDCs have estimated this amount as their incremental or marginal cost of distribution; that is, the change in cost of distribution incurred as demand for gas increases or decreases. The conclusion was that the incremental cost of distribution depends upon the load type and the customer sector. For low load factor or heating loads, more of the embedded cost for each sector is incremental or avoidable than for high load factor or non-heating loads. The incremental or avoidable cost is measured as a percent of the embedded costs. For AESC 2015, we measure the embedded cost as the difference between the city-gate price of gas in a state and the price charged each of the different retail customer types: residential, commercial/industrial, and all retail customers.[43] The embedded distribution cost for each of the two regions, Southern New England and Northern New England, were the weighted average distribution costs among the relevant states where the weighting is the volume of gas delivered to each sector in each state.

Exhibit 2-43 shows the estimated avoidable LDC margin percentage and avoidable costs, in 2013$ per MMBtu, by each of the end-use types and customer sectors for each region in New England.

Exhibit 2-43. Estimated Avoidable LDC Margins (2013$/MMBtu)

	LDC Average Retail Margin + City-Gate Cost (a)	Avoidable LDC Margin (a) Non-heating (High Load Factor)	Heating (Low Load Factor)	All
		%	%	
Avoidable Margin (percent) (b)				
Residential		8.0%	21.0%	20.4%
Commercial & Industrial		15.0%	28.0%	24.0%
All Retail				22.0%
Southern New England (c)		2015$/MMBtu		
Average City Gate Price	6.975			
Residential	7.709	0.62	1.62	1.57
Commercial & Industrial (e)	4.082	0.61	1.14	0.98
All Retail (f)	5.805			1.28
Northern New England (d)				
Average City Gate Price	8.454			
Residential	6.590	0.53	1.38	1.34
Commercial & Industrial (e)	3.198	0.48	0.90	0.77
All Retail (f)	3.676			0.81
Vermont				
Average City Gate Price	8.010			
Residential	9.087	0.73	1.91	1.85
Commercial & Industrial (e)	3.740	0.56	1.05	0.90
All Retail (f)	4.349			0.96

(a) Average of Margins among states for 2009-2013 weighted by the delivered volumes in each state.
(b) Based on LDC marginal cost studies from National Grid (MA).
(c) Southern New England is Massachusetts, Connecticut, and Rhode Island.
(d) Northern New England is New Hampshire and Maine.
(e) An average of the margins weighted by the commercial and industrial use delivered volumes.
(f) An average of residential, commercial and industrial margins weighted by associated volumes.

[43] The citygate gas prices and the prices charged to each retail customer sector are reported by the EIA for each state each year. In AESC 2015 the cost used is the average for 2009-2013, the most recent five years for which data is available.

Some LDCs assume they will not avoid any distribution costs due to reductions in gas use from efficiency measures. The avoided cost of gas by end-use for an LDC with no avoided distribution cost is their avoided cost of gas delivered to their citygate.

2.14.1 Total Avoided Gas Costs by End Use

Exhibit 2-44 through **Exhibit** 2-48 show the total avoided costs per year per MMBtu for the retail end-uses categorized by the end-use type and customer sector for Southern New England, Northern New England, and Vermont. The levelized avoided cost is the cost for which the present value at the real rate of return of 2.43 percent has the same present value as the estimated avoided costs for the 15-year period 2016 through 2030 at the same rate of return.

Exhibit 2-44 through Exhibit 2-46 present the avoided cost by end-use for utilities at which it is assumed that no LDC retail margin is avoidable.

Exhibit 2-44. Avoided Cost of Gas Delivered to LDCs by End-Use Load Type Assuming No Avoidable Retail Margin, Southern New England (2015$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non	Hot			Non			RETAIL
Year	Heating	Water	Heating	All	Heating	Heating	All	END USES
2015	4.45	4.90	5.06	4.94	4.61	4.92	4.78	4.87
2016	4.66	5.16	5.33	5.19	4.85	5.17	5.03	5.12
2017	5.36	6.02	6.24	6.07	5.60	6.02	5.85	5.96
2018	5.84	6.47	6.68	6.51	6.07	6.48	6.30	6.42
2019	5.89	6.40	6.57	6.44	6.08	6.42	6.27	6.36
2020	5.53	6.02	6.19	6.05	5.72	6.03	5.89	5.98
2021	5.83	6.34	6.51	6.37	6.02	6.35	6.20	6.30
2022	5.91	6.41	6.58	6.45	6.10	6.42	6.28	6.38
2023	6.00	6.50	6.67	6.53	6.19	6.51	6.37	6.45
2024	6.19	6.70	6.87	6.74	6.38	6.71	6.56	6.65
2025	6.31	6.80	6.97	6.83	6.50	6.81	6.68	6.76
2026	6.41	6.92	7.09	6.95	6.60	6.93	6.78	6.87
2027	6.49	7.00	7.17	7.03	6.68	7.01	6.86	6.95
2028	6.60	7.10	7.27	7.14	6.79	7.11	6.97	7.07
2029	6.80	7.30	7.46	7.34	6.99	7.30	7.17	7.26
2030	7.08	7.58	7.74	7.61	7.27	7.58	7.45	7.54
Levelized (a)	6.00	6.53	6.70	6.56	6.20	6.54	6.39	6.48
Simple Average	6.06	6.58	6.76	6.62	6.26	6.59	6.44	6.54

(a) Years 2016-2030 (15 years) at disciount rate of 2.430%
b Distribution system loss and unbilled 2%

Exhibit 2-45. Avoided Cost of Gas Delivered to LDCs by End-Use Load Type Assuming No Retail Margin, Northern New England (2015$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non	Hot			Non			RETAIL
Year	Heating	Water	Heating	All	Heating	Heating	All	END USES
2015	4.12	5.54	6.01	5.63	4.65	5.55	5.15	5.41
2016	4.64	5.30	5.52	5.34	4.88	5.31	5.13	5.24
2017	5.70	6.16	6.31	6.19	5.87	6.16	6.04	6.12
2018	5.98	6.76	7.02	6.82	6.28	6.77	6.55	6.69
2019	5.86	7.80	8.44	7.93	6.58	7.83	7.28	7.63
2020	5.48	7.41	8.06	7.54	6.20	7.45	6.90	7.25
2021	5.78	7.75	8.41	7.88	6.52	7.78	7.24	7.58
2022	5.87	7.85	8.51	7.98	6.61	7.88	7.33	7.67
2023	5.95	7.93	8.60	8.07	6.69	7.96	7.40	7.76
2024	6.14	8.16	8.84	8.30	6.90	8.19	7.62	7.98
2025	6.24	8.27	8.95	8.41	7.00	8.30	7.73	8.09
2026	6.35	8.40	9.08	8.53	7.11	8.43	7.85	8.22
2027	6.44	8.49	9.17	8.63	7.21	8.52	7.95	8.32
2028	6.54	8.60	9.29	8.74	7.31	8.63	8.05	8.42
2029	6.73	8.79	9.48	8.93	7.51	8.82	8.24	8.61
2030	7.01	9.07	9.76	9.21	7.78	9.10	8.52	8.89
Levelized (a)	6.00	7.69	8.25	7.80	6.63	7.71	7.24	7.54
Simple Average	6.05	7.78	8.36	7.90	6.70	7.81	7.32	7.63

(a) Years 2016-2030 (15 years) at disciount rate of 2.430%
b Distribution system loss and unbilled 2%

Exhibit 2-46. Avoided Cost of Gas Delivered to LDCs by End-Use Load Type Assuming No Retail Margin, Vermont (2015$/MMBtu)

Year	Design day	Peak Days	Remaining winter	Shoulder / summer
Days	1	9	141	214
	a	b	c	d
2015	$ 521.44	$ 15.66	$ 5.74	$ 4.55
2016	$ 521.62	$ 16.65	$ 6.04	$ 4.73
2017	$ 522.53	$ 18.45	$ 6.93	$ 5.64
2018	$ 522.94	$ 19.70	$ 7.00	$ 6.05
2019	$ 522.80	$ 20.19	$ 7.27	$ 5.91
2020	$ 522.50	$ 20.70	$ 6.92	$ 5.61
2021	$ 522.80	$ 21.24	$ 7.29	$ 5.91
2022	$ 522.97	$ 21.79	$ 7.43	$ 6.08
2023	$ 523.11	$ 22.37	$ 7.55	$ 6.22
2024	$ 523.28	$ 22.91	$ 7.76	$ 6.39
2025	$ 523.40	$ 23.41	$ 7.87	$ 6.51
2026	$ 523.53	$ 23.84	$ 8.03	$ 6.64
2027	$ 523.67	$ 24.37	$ 8.14	$ 6.78
2028	$ 523.78	$ 24.80	$ 8.26	$ 6.89
2029	$ 523.97	$ 25.24	$ 8.45	$ 7.08
2030	$ 524.24	$ 25.60	$ 8.72	$ 7.35
15yr Level	$ 523.08	$ 21.83	$ 7.51	$ 6.19

Exhibit 2-47 and Exhibit 2-48 are projections of avoidable cost by end-use for utilities in Southern New England and Northern New England for which some LDC retail margin is avoidable.

Exhibit 2-47. Avoided Cost of Gas Delivered to an End-Use Load, Assuming Some Retail Margin is Avoidable, Southern New England (2015$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non	Hot			Non			RETAIL
Year	Heating	Water	Heating	All	Heating	Heating	All	END USES
2015	5.06	6.27	6.68	6.51	5.23	6.06	5.76	6.42
2016	5.28	6.53	6.95	6.76	5.46	6.31	6.01	6.62
2017	5.98	7.38	7.85	7.64	6.21	7.17	6.82	6.62
2018	6.45	7.84	8.30	8.08	6.68	7.62	7.28	6.72
2019	6.50	7.77	8.19	8.01	6.69	7.56	7.25	6.96
2020	6.14	7.39	7.81	7.63	6.33	7.17	6.87	7.25
2021	6.45	7.71	8.13	7.94	6.63	7.49	7.18	7.59
2022	6.53	7.78	8.20	8.02	6.71	7.56	7.26	7.84
2023	6.62	7.87	8.28	8.10	6.80	7.65	7.35	7.99
2024	6.81	8.07	8.49	8.31	6.99	7.85	7.54	8.19
2025	6.92	8.17	8.59	8.41	7.11	7.96	7.66	8.31
2026	7.03	8.28	8.70	8.52	7.21	8.07	7.76	8.45
2027	7.11	8.36	8.78	8.60	7.29	8.15	7.84	8.63
2028	7.22	8.47	8.89	8.72	7.41	8.25	7.95	8.76
2029	7.41	8.67	9.08	8.91	7.60	8.45	8.15	8.88
2030	7.69	8.94	9.36	9.19	7.88	8.73	8.43	8.98
Levelized (a)	6.62	7.89	8.32	8.13	6.81	7.68	7.37	7.77
Simple Average	6.68	7.95	8.37	8.19	6.87	7.73	7.42	7.85

(a) Years 2016-2030 (15 years) at disciount rate of 2.430%
b Distribution system loss and unbilled 2%

Exhibit 2-48. Avoided Cost of Gas Delivered to an End-Use Load, Assuming Some Retail Margin is Avoidable, Northern New England (2015$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
Year	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	RETAIL END USES
2015	4.65	6.71	7.39	6.97	5.13	6.45	5.92	5.95
2016	5.17	6.47	6.90	6.68	5.36	6.20	5.89	6.15
2017	6.22	7.33	7.69	7.54	6.35	7.06	6.80	6.15
2018	6.51	7.93	8.40	8.16	6.76	7.67	7.32	6.25
2019	6.38	8.97	9.83	9.27	7.06	8.73	8.05	6.49
2020	6.01	8.58	9.44	8.89	6.68	8.34	7.66	6.78
2021	6.31	8.92	9.79	9.22	7.00	8.68	8.00	7.12
2022	6.40	9.02	9.89	9.33	7.09	8.77	8.09	7.37
2023	6.47	9.10	9.98	9.41	7.17	8.86	8.17	7.52
2024	6.66	9.33	10.22	9.64	7.38	9.09	8.39	7.72
2025	6.77	9.44	10.33	9.75	7.48	9.20	8.50	7.84
2026	6.87	9.57	10.46	9.88	7.59	9.32	8.61	7.98
2027	6.96	9.66	10.56	9.98	7.69	9.41	8.71	8.16
2028	7.07	9.77	10.67	10.08	7.79	9.53	8.82	8.29
2029	7.26	9.96	10.86	10.27	7.98	9.72	9.01	8.41
2030	7.54	10.24	11.14	10.55	8.26	10.00	9.29	8.51
Levelized (a)	6.52	8.86	9.64	9.15	7.11	8.61	8.01	7.30
Simple Average	6.57	8.95	9.75	9.24	7.18	8.70	8.09	7.38

(a) Years 2016-2030 (15 years) at disciount rate of 2.430%
b Distribution system loss and unbilled 2%

2.14.2 Comparison of Avoided Retail Gas Costs with AESC 2013

Exhibit 2-49 and Exhibit 2-50 show the end-use avoided costs of gas use in AESC 2015 as compared to AESC 2013 assuming no avoided margin and some avoided margin respectively. The end-use avoided costs of gas use in AESC 2015 are generally less than estimated in AESC 2013 for all three regions in New England.

Exhibit 2-49. Comparison of AESC 2015 and AESC 2013 Avoided Cost of Gas Delivered to Retail Customers by End Use Assuming NO Retail Margin Avoidable (2015$/MMBtu, unless noted)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (CT, MA, RI)								
AESC 2013 (2013$)	6.08	6.57	6.73	6.60	6.26	6.58	6.44	6.53
AESC 2013 (b)	6.29	6.80	6.97	6.83	6.48	6.81	6.66	6.76
AESC 2015	6.00	6.53	6.70	6.56	6.20	6.54	6.39	6.48
2013 to 2015 change	-5%	-4%	-4%	-4%	-4%	-4%	-4%	-4%
Northern New England (ME, NH)								
AESC 2013 (2013$)	6.03	7.53	8.02	7.62	6.58	7.54	7.12	7.39
AESC 2013 (b)	6.24	7.80	8.30	7.89	6.82	7.81	7.37	7.65
AESC 2015	6.00	7.69	8.25	7.80	6.63	7.71	7.24	7.54
2013 to 2015 change	-4%	-1%	-1%	-1%	-3%	-1%	-2%	-1%

	Design day	**Peak Days**	**Remainin g winter**	**Shoulder / summer**
Vermont				
AESC 2013 (2013$)	$ 389.03	$ 20.68	$ 8.68	$ 6.32
AESC 2013 (b)	$ 402.76	$ 21.41	$ 8.98	$ 6.54
AESC 2015	$ 523.08	$ 21.83	$ 7.51	$ 6.19
2013 to 2015 change	30%	2%	-16%	-5%

Factor to convert 2013$ to 2015$ 1.0353

Note: AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.
AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.

Exhibit 2-50. Comparison of AESC 2015 and AESC 2013 Avoided Cost of Gas Delivered to Retail Customers by End-Use Assuming SOME Retail Margin Avoidable (2015$/MMBtu, unless noted)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	RETAIL END USES
Southern New England (CT, MA, RI)								
AESC 2013 (2013$)	6.67	7.17	8.30	8.12	6.88	7.74	7.44	7.80
AESC 2013 (b)	6.91	7.42	8.59	8.41	7.13	8.01	7.70	8.07
AESC 2015	6.62	7.89	8.32	8.13	6.81	7.68	7.37	7.35
2013 to 2015 change	-4%	6%	-3%	-3%	-4%	-4%	-4%	-9%
Northern New England (ME, NH)								
AESC 2013 (2013$)	6.53	8.04	9.35	8.91	7.04	8.40	7.86	8.17
AESC 2013 (b)	6.76	8.32	9.68	9.23	7.29	8.70	8.14	8.46
AESC 2015	6.52	8.86	9.64	9.15	7.11	8.61	8.01	6.88
2013 to 2015 change	-4%	6%	0%	-1%	-3%	-1%	-2%	-19%

Factor to convert 2013$ to 2015$ 1.0353

Note: AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.
AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.

2.15 Avoided Natural Gas Capacity Costs

The AESC 2015 scope of work requires a recommendation as to whether a separate natural gas capacity value should be developed and introduced into program administrator benefit-cost models. The scope of work further requests, depending on the recommendation, an estimate of peak-day $/MMBtu (capacity value). This section provides that recommendation and also provides a projection of avoided peak-day costs.

AESC 2015 does not recommend development of a separate natural gas capacity value until the program administrators demonstrate a need to evaluate gas efficiency measures that reduce peak day sendout only, rather than reducing gas commodity use plus peak day sendout. This recommendation is based upon the same reasons discussed in prior AESC studies, in particular AESC 2011 pages 4-17 through 4-19. The primary reason is pragmatic, and arises from the key differences between the gas industry and the electric industry relative to the calculation of, and application of, avoided capacity costs as summarized below.

First, the electric industry has demand response measures which reduce peak demand in a few high use hours each year and thereby primarily avoid capacity costs. In contrast, the gas industry does not appear to have measures which reduce gas use solely on a peak day. (In this regard it is important to recognize that gas utilities acquire peaking resources to meet their “design day” requirements which is a needle peak demand on 1 day with exceptional colder-than-normal temperatures that occur perhaps only once in 30 years. They acquire a different set of winter season supply resources to meet their requirements in in each month of a colder-than-normal design winter).

Second, the avoided "capacity value" of gas efficiency programs that reduce gas use with different load profiles is embedded in the avoided costs by end-use that we have developed. The avoided capacity cost of efficiency measures that reduce gas used for heating end-uses consists of avoided pipeline capacity costs, avoided storage service capacity costs and avoided peaking resource capacity costs. All of those avoided capacity costs are included in the avoided cost of heating uses that we provided, and they reflect the load factor at which utilities use each of those sources of capacity. The same applies for efficiency measures that reduce gas use for residential water heating or for non-heating purposes.

To the extent some program administrators do want an avoided cost of peak day use, we provide projections in Exhibit 2-51 for Southern New England (SNE), Northern New England (NNE) and Vermont. These estimates are based upon the same resource assumptions as in AESC 2013, i.e., avoided on system LNG liquefaction and vaporization for SNE and NNE, and propane peaking in Vermont.

Exhibit 2-51. Avoided Cost of Peak Day Use

AVOIDED PEAK DAY COSTS (2015$/Dekatherm)			
	Southern New England (1)	Northern New England (1)	Vermont (2)
2015	$ 10.69	$ 10.69	$ 521.44
2016	$ 8.31	$ 8.31	$ 521.65
2017	$ 9.49	$ 9.49	$ 522.54
2018	$ 10.16	$ 10.16	$ 522.41
2019	$ 10.41	$ 10.41	$ 522.84
2020	$ 9.99	$ 9.99	$ 522.49
2021	$ 10.60	$ 10.60	$ 522.83
2022	$ 10.75	$ 10.75	$ 522.98
2023	$ 10.90	$ 10.90	$ 523.10
2024	$ 11.38	$ 11.38	$ 523.30
2025	$ 11.54	$ 11.54	$ 523.40
2026	$ 11.79	$ 11.79	$ 523.56
2027	$ 11.94	$ 11.94	$ 523.67
2028	$ 12.07	$ 12.07	$ 523.78
2029	$ 12.26	$ 12.26	$ 523.97
2030	$ 18.73	$ 18.73	$ 542.13
Notes			
1	Avoided resource is on-system LNG liquefaction / vaporization		
2	Avoided resource is on-system propane peaking		

2.16 Assessment of Alternative Natural Gas Costing Periods

The Study Group asked TCR to analyze the avoided natural gas cost results and assess whether alternative costing period definitions may more accurately and reasonably reflect the seasonal and hourly variation of marginal energy costs in comparison to the definitions presented in Task 3A 1 of the scope of work. This section describes our analysis of alternative costing period definitions for natural gas costs, and our recommendations based on that analysis.

The key point from our analysis is that the current natural gas costing periods for the residential, commercial and industrial ("RC&I") sectors are fundamentally different from the current definitions of electric energy costing periods.

- Electric energy costing periods are currently defined in terms of the time period during which electric energy is used. Program administrators use the avoided electric energy costs for each time period to calculate the avoided cost of reductions in various types of electric energy end-use according to the shape of those reductions by time period.
- In contrast, natural gas costing periods for the RC&I sectors are currently defined in terms of the sector in which gas is used and the end-uses for which natural gas is used within that sector. As a result, the avoided natural gas costs resulting from the current natural gas costing periods reflect both the time period during which electric energy is used and the shape of the natural gas end-use.

Our analysis focuses on the costing periods for the residential, commercial and industrial ("RC&I") sectors for two reasons. First, our analysis did not find any problems with the natural gas costing periods used for electric generation. AESC 2015 and prior AESC studies estimate the average daily cost of natural gas for electric generation by month. That costing period and approach is reasonable for a long-term projection of avoided electric generation costs. Although the price of natural gas for electric generation varies by day within each month, in the long-term the daily prices in a given month are not materially different than the average price for that month. Second, the factors driving the avoided cost of gas for electric generation during a specific time period are different from those driving the avoided cost of gas for the RC&I sectors. The price of gas for electric generation is determined by the wholesale gas market in New England. In contrast, the avoided cost of gas for the RC&I sectors is determined by the wholesale gas market at production area hubs, such as the Henry Hub, plus the regulated costs of pipeline transportation, storage services and peaking facilities.

2.16.1 Current Natural Gas Costing Periods versus Electric Energy Costing Periods

The natural gas costing periods used in AESC 2015, and in prior AESC studies, are defined in terms of the sector in which gas is used and the end-uses for which natural gas is used within that sector. Task 3A1 defines the costing periods as:

a. Electric generation:
b. Commercial and industrial non-heating
c. Commercial and industrial heating

d. Residential heating
e. Residential water heating
f. Residential non-heating
g. All commercial and industrial
h. All residential
i. All retail end uses

In contrast, electric energy costing periods are currently defined in terms of the time period during which electric energy is used. Aggregate electric energy load, and electric energy prices, vary by season (winter, summer), by day of week (i.e. weekdays versus weekends), and by hour within weekdays (i.e. on-peak 7 am to 11 pm; off-peak 11 pm to 7 am). The electric energy costing periods used in AESC 2015, and in prior AESC studies, reflect those variations in load and price by time period. The four current electric energy costing periods are:

a. Winter (October – May), on-peak (weekdays 7 am to 11 pm)
b. Winter (October – May), off-peak (weekdays 11 pm to 7 am weekdays, weekends, and holidays)
c. Summer (June - September), on-peak (weekdays 7 am to 11 pm)
d. Summer (June - September), off-peak (weekdays 11 pm to 7 am, weekends, and holidays).

Natural gas load for the RC&I sectors in aggregate, and the costs of natural gas to serve that aggregate load, also vary by winter and summer. Winter in the gas industry is November through March (151 days) and summer is April through October (214 days). The cost of natural gas to serve that aggregate load varies by day during sub-periods within the winter, rather than by hour and by weekday versus weekend in the electric industry. Two commonly used sub-periods within the winter are peak days (i.e. top 10 coldest days) and shoulder days (i.e., remaining 141 days). For example, in this study Vermont Gas Systems has requested that we calculate avoided costs for four periods per year, i.e., a design day, 9 peak days, 80 shoulder days and 275 baseload days.

AESC 2015, and prior AESC studies, have developed annual avoided costs for the RC&I sectors in three steps, as illustrated in Exhibit 2-52. Step one is to identify the marginal resource used to supply load during the relevant gas industry costing period and the avoided cost of that resource. For example, the marginal resource in the 10 peak days may be a peaking service with a marginal cost of $8.62/MMbtu... Step two is to determine the portion of each RC&I end-use load that occurs in each gas industry costing period. For example, 2.7% of non-heating load may occur in the 10 peak days. Step three is to multiply the avoided cost in each costing period by the percentage load in that costing period, and add all the resulting costs by costing period to calculate the annual avoided cost for each end-use. For example, if .02 percent of residential heating load occurs during peak days and 99.9 percent occurs during shoulder days, the avoided cost of a reduction in residential heating load would be $6.60/MMBtu as illustrated in Exhibit 2-52.

Exhibit 2-52. Illustration of Avoided Costs by Sector and End-Use

Avoided Resource and Cost by Costing Period				Portion of Residential End-Use by Costing Period			Avoided Cost by Residential End-Use		
Costing Period	Days	% of year	Avoided Cost $/MMBtu	Non-heating load	Water heating load	Heating load	Non-heating load	Water heating load	Heating load
			a	b	c	d	e = a *b	e = a *c	e = a *d
Peak	10	2.7%	$ 8.62	2.7%	0.1%	0.2%	$ 0.24	$ 0.01	$ 0.02
Shoulder	141	38.6%	$ 6.60	38.6%	75.4%	99.8%	$ 2.55	$ 4.98	$ 6.59
Baseload	214	58.6%	$ 5.01	58.6%	24.5%	0.0%	$ 2.94	$ 1.23	$ -
Total	365	100.0%		100.0%	100.0%	100.0%	$ 5.72	$ 6.21	$ 6.60

Based on a review of gas utility filings and prior AESC studies, AESC 2015 recommends that Program Administrators consider changing the costing periods for natural gas in future AESC studies to three resource based costing periods – peak days (10), shoulder days (141) and baseload days (214). These costing periods would be methodologically consistent with those used to calculate avoided electric energy costs. Program administrators can then use the avoided gas costs for each time period to calculate the avoided cost of reductions in various types of gas end-use according to the shape of those reductions by time period.

In order to apply these resource based costing periods PAs would have to be able to determine the portion of each RC&I end-use load that occurs in each costing period. PAs should be able to obtain that load shape information from the gas utility supplying their service territory. Gas utilities typically have formulae for predicting gas use per customer by month for each major rate class. For example, a formula for residential heating use per customer might be zero base use per day + 0.012 Dth per heating degree day (HDD) while the formula for residential n0n-heating use per customer might be 0.04 Dth/day plus + zero Dth per HDD. PAs would use these formulae, plus the HDD per month, to project the load shape of each major end use.

Chapter 3: Avoided Costs of Fuel Oil and Other Fuels by Sector

3.1 Introduction

This draft deliverable presents our forecasts of avoided costs for petroleum products used in electric generation as well as in the residential, commercial, and industrial sectors in New England. All of these forecasts are driven by our forecast of crude oil prices. For the electricity generation sector, we forecast avoided costs of No. 2 (distillate) and No. 6 (residual). For the residential, commercial and industrial sectors we forecast avoided costs of those two grades and of propane. In addition, for the residential sector we also forecast avoided costs of other fuels used for heating purposes, specifically a biofuel blend (B20), kerosene, cordwood, and wood pellets.

The AESC 2015 forecasts for crude oil and petroleum fuels for electric generation are presented in Exhibit 3-1. Crude Oil and Fuel Prices for Electric Generation (2015$). The AESC 2015 forecasts for fuel oil and other fuels in the residential, commercial and industrial sectors are presented in Exhibit 3-2.

Exhibit 1 7 presents the AESC 2015 fifteen year levelized avoided costs for selected fuels in the residential and commercial sectors, as well as the comparable levelized costs from AESC 2013

3.2 Forecast of Crude Oil Prices

AESC 2015, like the AESC 2013 Study, recognizes that crude oil prices constitute the dominant component of petroleum product prices. The AESC 2015 forecast of crude oil prices begins with the forecast of crude oil (West Texas Intermediate or WTI) from the EIA AEO 2014 Reference case, which was prepared in the fall of 2013. Our analyses use prices of WTI for this comparison because it is reflects domestic markets, is actively traded, and its price in the past has been very close to that of the low-sulfur light crude used in EIA's Reference Case.

We then make a downward adjustment to the projected costs of crude and petroleum products to reflect changes in the outlook since AEO 2014 was prepared. That adjustment is based on our assessment of recent trends in U.S. oil production and the significant drop in oil prices in the last six months and revised outlook as reflected in current NYMEX futures prices.[44]

[44] AESC 2015 projections using NYMEX all rely on settlement prices as of December 18, 2014.

Exhibit 3-1. Crude Oil and Fuel Prices for Electric Generation (2015$)

Year		Crude Oil Prices				Electric Generation (1)	
		AEO 2014 Reference case WTI	WTI NYMEX Futures as of December 18 2014	AESC 2015 Forecast WTI		Distillate Fuel Oil	Residual Fuel Oil
		$/MMBtu	$/MMBtu	$/MMBtu	$/BBl	$/MMBtu	$/MMBtu
		2015$	2015$	2015$	2015$	2015$	2015$
2015		$ 16.21	$ 9.65	$ 9.72	$ 56.40	$ 12.77	7.11
2016		$ 15.90	$ 10.25	$ 10.34	$ 59.96	$ 13.37	7.38
2017		$ 16.10	$ 10.58	$ 11.46	$ 66.46	$ 14.44	7.91
2018		$ 16.31	$ 10.68	$ 12.23	$ 70.94	$ 15.38	8.42
2019		$ 16.72	$ 10.69	$ 12.54	$ 72.74	$ 15.76	8.64
2020		$ 17.14	$ 10.61	$ 12.85	$ 74.54	$ 16.13	8.94
2021		$ 17.59	$ 10.45	$ 13.19	$ 76.50	$ 16.51	9.20
2022		$ 18.04	$ 10.26	$ 13.53	$ 78.49	$ 16.90	9.62
2023		$ 18.52	$ 10.06	$ 13.89	$ 80.57	$ 17.25	9.88
2024		$ 18.97		$ 14.23	$ 82.52	$ 17.61	10.08
2025		$ 19.39		$ 14.54	$ 84.33	$ 17.93	10.29
2026		$ 19.74		$ 14.80	$ 85.86	$ 18.18	10.64
2027		$ 20.18		$ 15.13	$ 87.77	$ 18.52	10.99
2028		$ 20.53		$ 15.40	$ 89.32	$ 18.74	11.09
2029		$ 20.90		$ 15.68	$ 90.92	$ 19.02	11.50
2030				$ 15.90	$ 90.92	$ 19.02	11.50
Levelized Costs							
2016-2025	10			$12.80	$74.22	$16.04	$8.97
2016-2030	15			$13.55	$78.54	$16.82	$9.61

Exhibit 3-2. Avoided Costs of Fuel Oil and Other Fuels by Sector (2015$)

Year		Residential						Commercial		Industrial	
		Distillate Fuel Oil	Propane	Kerosene	B20	Cord Wood	Wood Pellets	Distillate Fuel Oil	Residual Fuel	Distillate Fuel Oil	Residual Fuel
		$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
		2015$	2015$	2015$	2015$	2015$	2015$	2015$	2015$	2015$	2015$
2015		$ 15.35	$ 14.10	$ 16.75	$ 14.94	$ 5.44	$ 6.19	14.09	12.67	13.80	12.67
2016		$ 16.17	$ 15.29	$ 17.64	$ 15.73	$ 5.73	$ 6.52	14.91	13.41	14.67	13.41
2017		$ 17.51	$ 17.14	$ 19.10	$ 17.04	$ 6.20	$ 7.06	16.23	14.51	16.04	14.51
2018		$ 18.61	$ 18.38	$ 20.30	$ 18.11	$ 6.59	$ 7.50	17.28	15.37	17.09	15.37
2019		$ 18.99	$ 18.57	$ 20.72	$ 18.48	$ 6.73	$ 7.65	17.69	15.60	17.52	15.60
2020		$ 19.36	$ 18.70	$ 21.12	$ 18.84	$ 6.86	$ 7.80	18.05	15.89	17.88	15.89
2021		$ 19.74	$ 18.92	$ 21.53	$ 19.20	$ 6.99	$ 7.95	18.44	16.15	18.27	16.15
2022		$ 20.13	$ 19.09	$ 21.96	$ 19.58	$ 7.13	$ 8.11	18.85	16.57	18.70	16.57
2023		$ 20.48	$ 19.21	$ 22.34	$ 19.93	$ 7.25	$ 8.25	19.18	16.83	19.00	16.83
2024		$ 20.84	$ 19.37	$ 22.73	$ 20.27	$ 7.38	$ 8.40	19.49	17.03	19.29	17.03
2025		$ 21.16	$ 19.55	$ 23.09	$ 20.59	$ 7.50	$ 8.53	19.82	17.24	19.63	17.24
2026		$ 21.41	$ 19.70	$ 23.35	$ 20.83	$ 7.58	$ 8.63	20.08	17.60	19.89	17.60
2027		$ 21.75	$ 19.85	$ 23.73	$ 21.17	$ 7.71	$ 8.77	20.42	17.94	20.22	17.94
2028		$ 21.97	$ 19.98	$ 23.97	$ 21.38	$ 7.78	$ 8.85	20.63	18.04	20.42	18.04
2029		$ 22.25	$ 20.12	$ 24.27	$ 21.65	$ 7.88	$ 8.97	20.90	18.45	20.69	18.45
2030		$ 22.47	$ 20.25	$ 24.51	$ 21.87	$ 7.96	$ 9.06	$ 21.13	$ 18.65	$ 20.93	$ 18.65
Levelized Costs											
2016-2025	10	$19.20	$18.35	$20.94	$18.68	$6.80	$7.74	$17.90	$15.79	$17.71	$15.79
2016-2030	15	$20.01	$18.83	$21.83	$19.47	$7.09	$8.06	$18.70	$16.47	$18.51	$16.47

3.2.1 Increase in U.S. Tight Oil Production

Just as U.S. natural gas production increased steeply since 2009, so too has oil and liquids production. Since 2010, as documented in AESC 2013, drillers have been moving aggressively to shift their focus toward shale plays that have been more liquids-prone than dry-gas prone, e.g., preferring plays like the Eagle Ford, Permian, Bakken and Niobrara fields. These shifts have been motivated not only by high global oil prices, but also by the ready ability to sell and export co-produced natural gas liquids (and, more recently, condensates as well). In addition, producers have been able to improve cash flows by selling off by-product natural gas in shale fields where gas can be transported and stored using a base of existing infrastructure, e.g., especially in Texas, from the prolific Eagle Ford and Permian Basin oil-prone regions.

The resulting surge in production of oil and liquids is shown in

Exhibit 3-3. U.S. tight oil production[45] surpassed 4 million barrels per day (MBD) before the end of 2014, and appeared on its way to continue increasing in 2015, despite lower crude oil prices and a lower rig count.[46] U.S. tight oil production appears heading toward the 5-6 MBD range, as matters stood in December 2014.

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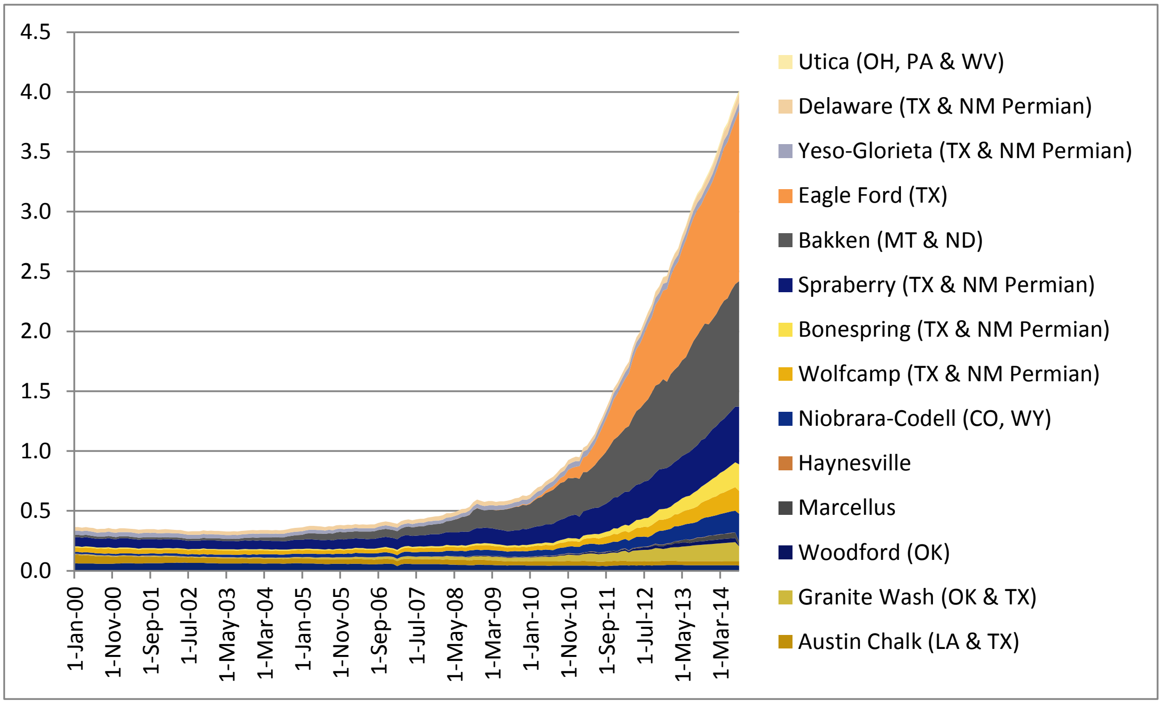
[45] The term “tight oil” is loosely applied to a number of light crude oil and condensate liquids produced from shale wells.

[46] EIA, Today in Energy, “Despite lower crude oil prices, U.S. crude oil production expected to grow in 2015,” January 2, 2015.

Exhibit 3-3. U.S. Monthly Tight Oil Production, by Field, million bbl/day



Source: EIA Administrator Adam Sieminski, in presentation before the US-Canada Energy Summit, Chicago, IL, October 17, 2014; compiled from state administrative data collected by DrillingInfo Inc. Data are through August 2014 and represent EIA's official tight oil & shale gas estimates, but are not survey data. State abbreviations indicate primary state(s).

Increased U.S .oil production since 2010 has, in turn, produced a corresponding and unexpected sharp decline in U.S. oil imports, thereby weakening global oil prices. Indeed, the decline in global crude oil prices that began in late summer 2014 has resulted in part from increased U.S. tight oil production, a linkage that has become clear since the AESC 2013 report. Moreover, global oil market participants observe the rate of U.S. oil production increases shown in

Exhibit 3-3 and, thereby, reasonably anticipate further reductions in U.S. oil importation.

At the same time U.S. oil production has been rising and oil imports have been declining, continuing economic weakness in Europe, Russia and the Asia Pacific region have contributed to relatively stagnant demand for petroleum products globally. In addition, structurally reduced oil demand in the U.S., hitherto the world's largest oil consumer, has resulted from increasingly stringent vehicle efficiency standards.[47] Thus, stagnant global oil demand and rising U.S. oil production have combined to weaken

[47] This includes tightening under both the Bush and Obama Administrations of U.S. Corporate Average Fuel Economy (CAFE) standards and corresponding penalties, as well as the DOE's Advanced Technology Vehicles Manufacturing (ATVM) loans which, again under both Administrations, have launched quantum improvements in hybrid and battery all-electric vehicle

global oil markets significantly – and both conditions are likely to persist into 2015. Eventually, cash-strapped OPEC countries will succeed in raising crude oil prices, although we do not expect OPEC will be able to restore crude prices to the levels seen from 2012 to 2014. Consequently, AESC 2015 projects levelized crude oil prices of $12.30 per MMBtu (2015$) over the next decade, as shown in Exhibit 3-1, which corresponds to a levelized price of $71.36 per barrel (2015$).

3.2.2 Impact of Lower Crude Oil prices in 2014

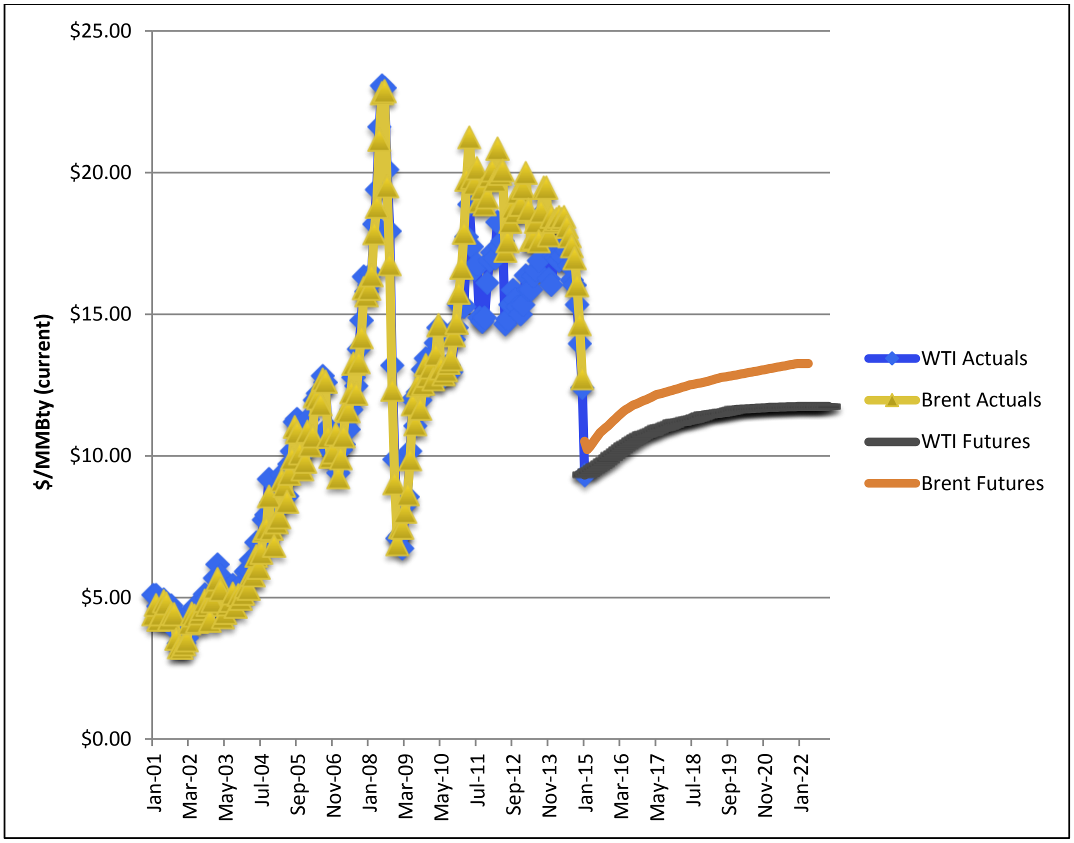
Following on the foregoing discussion of why crude oil price have fallen, analysts are currently debating a number of inter-related questions:

- Why, when, at what levels, and how many times will oil prices hit bottom?
- What will be the effects on U.S. tight oil production, and the U.S. economy?
- How will recent, less aggressive WTI crude forecasts play into future fuel oil prices for DFO and RFO, and competition with natural gas?

To appreciate the questions and think about the answers, one of the important distinctions in global crude prices is the difference between spot and futures (or forward) market prices. As demonstrated in Exhibit 3-4, global oil commodity futures markets anticipate that global and U.S. benchmark prices, respectively Brent and West Texas Intermediate (WTI), will for various reasons stabilize somewhat above current spot price levels. In general, crude markets anticipate somewhat recovered crude oil prices because of the rising need for cash on the part of some OPEC members, recovering demand, and increasing pressures to raise or at least stabilize prices.

technologies. See, for example, the EIA's discussion at http://www.eia.gov/todayinenergy/detail.cfm?id=7390 and the DOE's review at http://energy.gov/lpo/services/atvm-loan-program.

Exhibit 3-4. Monthly Prices of Natural Gas and Crude Oil – Actuals and Futures, 2001-2022



Source: CME-NYMEX, settlement prices at December 18, 2014; note figure plots past monthly spot prices for Henry Hub gas, WTI crude oil and Brent, as well as recent closing futures prices on CME-NYMEX for each of these same three commodities.

Even before global oil prices began to decline in 2014, U.S. tight oil producers were already aggressively moving to improve recovery and management technologies. Such drilling enhancements have reportedly reduced break-even points (BEP) and increasing per-barrel returns to producers.[48] No systematic, timely analyses of this effect are yet available in public literature, although early reports appear to suggest workable BEPs in the major tight oil-producing areas have variously fallen from crude oil prices of $50 per barrel to $70 per barrel, to as low as the $30 to $50 range.[49]

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[48] In general, the break-even point is the point at which the discounted profit-to-investment ratio equals one, i.e., the net operating income over time of a project equals the sum of investments over time, taking into consideration the time value of money (Society of Petroleum Engineers, Petroleum Economics, see petrowiki.org/PEH%3APetroleum_Economics#cite_note-r9-8).

[49] Note October 2014 estimates of analysts at EIA, Morgan Stanley, GlobalData Ltd. cited in http://www.bloomberg.com/news/2014-10-14/u-s-shale-oil-output-growing-even-as-prices-drop-eia.html

Energy economist Phillip K. Verleger, a practicing oil market analyst for four decades, posits that, even if there is a repeat of the unbridled crude oil price collapse of 1989-1999, "…cash WTI decreases to $45 per barrel, while forward prices fall to around $72. Such declines would have important implications for North American crude production. [However] forward oil at $72 would probably provide sufficient incentive to maintain activity in the Bakken, Eagle Ford Shale, Julesburg, and Permian Basin shale."[50] Verleger wisely cautions that all such forecasts and analogies are fraught with risk.

In summary, we anticipate U.S. tight oil production will continue on a path to at least 5 MBD, and possibly as high as 8 MBD.[51] We anticipate this will force OPEC members finally to agree, perhaps in a series of meetings throughout the winter of 2014-2015, to reduced production quotas. Such agreement will, in turn, stabilize crude oil prices and avert a repeat of the 1998-1999 oil price war, or shorten (or prevent) a price war that might otherwise take place.

3.3 AESC 2015 WTI Forecast versus AEO 2014 Reference Case and December 2014 Futures Prices

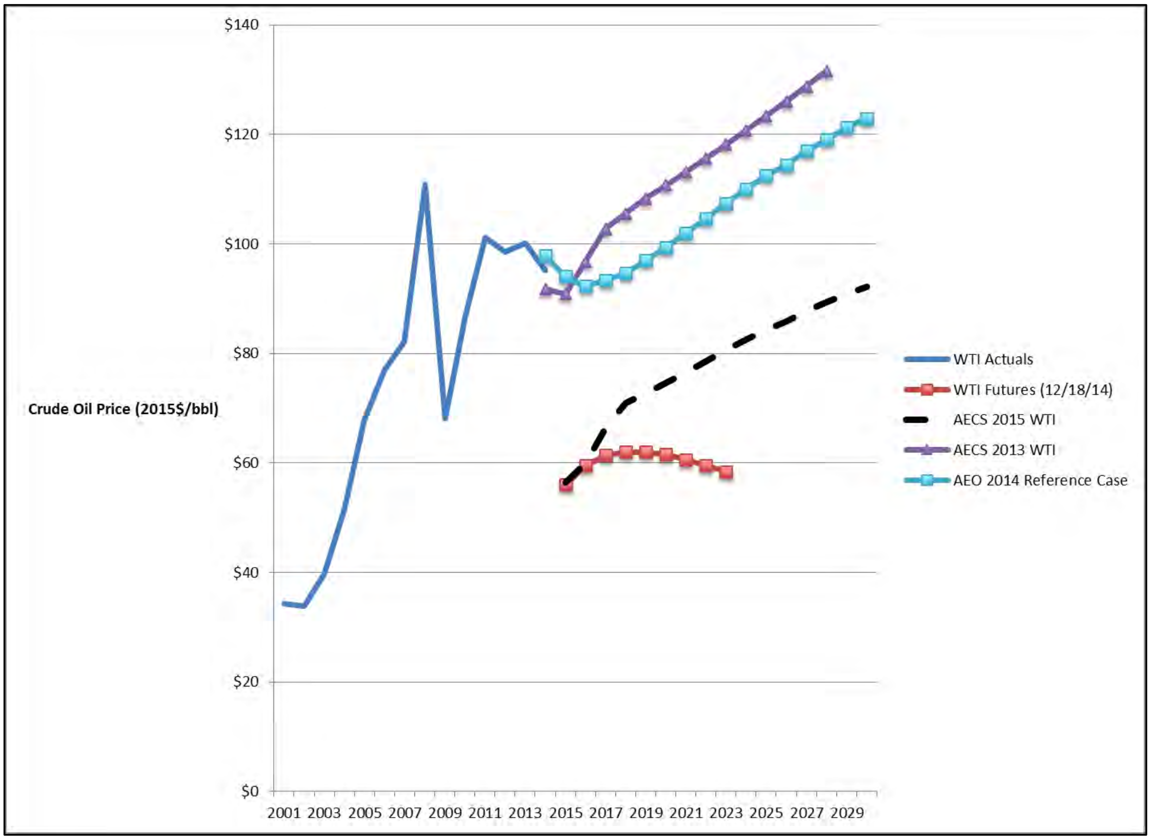
Our first step in developing a forecast of crude oil prices was to compare the EIA AEO 2014 Reference Case forecast of WTI prices with NYMEX futures prices for WTI as of December 18, 2014.

Just as in AESC 2013, this comparison revealed a significant difference between NYMEX futures for WTI in the medium to long term, and the AEO Reference Case forecast prices. That disparity is presented in **Exhibit** 3-5 which plots, in 2015 dollars per bbl, (1) actual WTI oil prices since 2001, (2) WTI futures through 2022, (3) AEO 2014 Reference Case forecasts, and (4) AESC 2013 and 2015 forecast prices through 2028 and 2030, respectively.

50 Phillip K. Verleger, "Notes at the Margin: Oil Price War 3.0," Vol XVIII, No. 42, October 13, 2014.

51 This range is consistent with the range of tight oil production increases in the AEO 2014 Reference Case and High Oil & Gas Resource Case, respectively.

Exhibit 3-5. WTI Crude Price History, Annual Average NYMEX Futures as of December 18, 2014, and AEO and AESC Forecasts (2015$ per bbl)



The exhibit shows that the AEO 2014 Reference Case projections of crude oil prices differ dramatically from NYMEX futures as of December 2014.

The AESC 2015 Base Case forecast of crude oil prices reflects an average 25% downward adjustment to the AEO 2014 Reference Case forecast to reflect changes in the oil market outlook since AEO 2014 was prepared. We make this level of adjustment in the crude oil and corresponding petroleum product price projections because we believe from our understanding of current and expected oil markets that forward oil prices throughout the AEO 2014 Reference Case are overstated by about 25% to 30%, hence an average 25% downward adjustment is conservative. AEO 2015 will not be released by EIA in time to include its oil market insights and forecast as price drivers for AESC 2015. Indeed, our understanding is that the early release of AEO 2015, previously scheduled for mid-December 2014 , has been held up for much these reasons, in particular, to afford EIA sufficient time to revise its crude oil and petroleum product price projections. We expect the AESC 2015 Base Case forecast of crude oil prices, to be generally consistent with oil market forecasts in the forthcoming AEO 2015 Reference Case.

With the foregoing in mind, the AESC 2015 forecast of WTI crude oil prices (the dashed line in **Exhibit** 3-5) begins in 2015 and 2016 with average annual NYMEX WTI crude settlement prices in each year, which, respectively equal 60% and 65% of the AEO 2014 Reference Case WTI crude oil price projections in these two years. During the long-term forecast years, 2018 through 2030, AESC 2015 crude prices equal 75% of the AEO 2014 Reference Case crude forecast, as described above. During 2017, the AESC 2015 price transitions to the long-term forecast level, equaling 72% of the AEO 2014 Reference Case WTI price forecast.

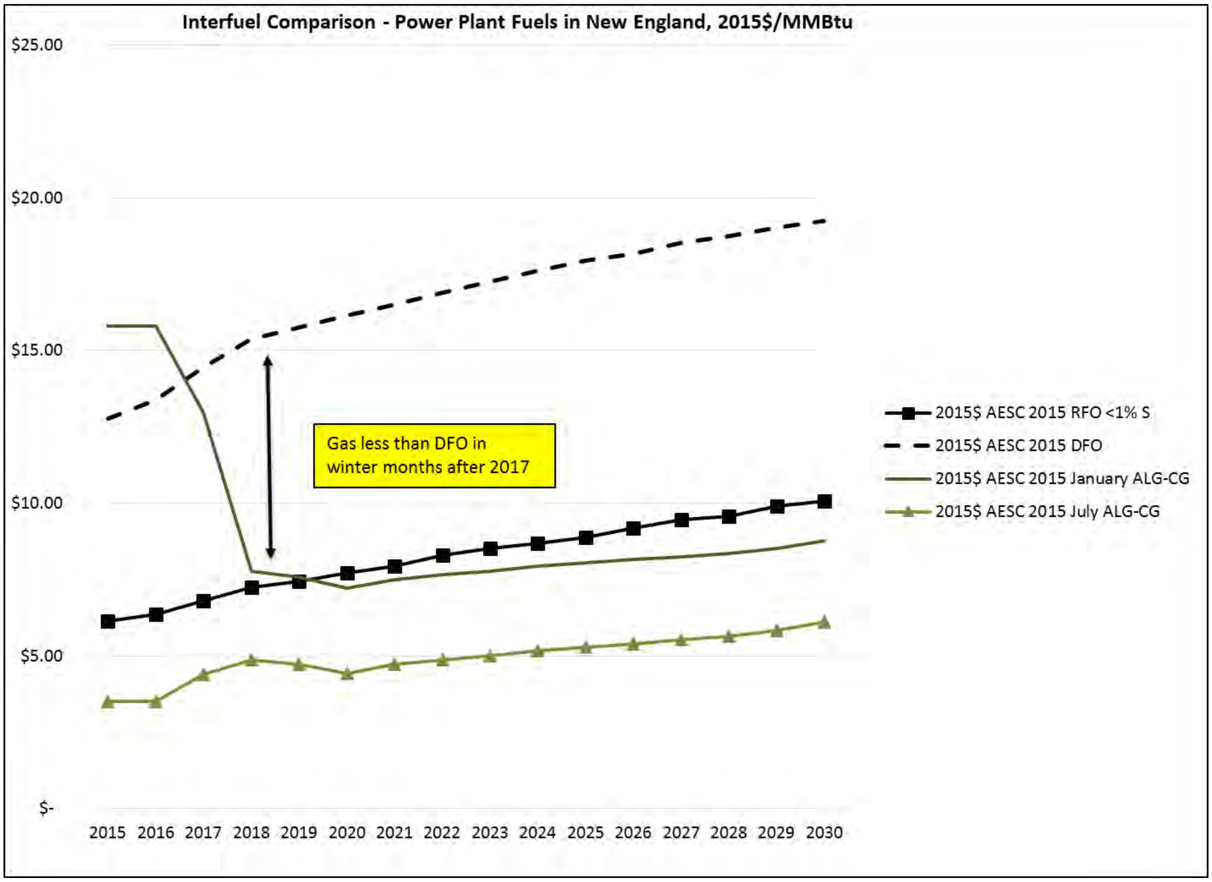
3.4 Avoided Costs of Fuel for Electric Generation

AESC 2015 provides forecasts of prices for distillate, residual, and coal for electricity generation in New England.

3.4.1 Forecast Prices of Distillate and Residual

AESC 2015 forecasts of distillate fuel oil (DFO) and residual fuel oil (RFO) for electric generation reflect the same level of discount from the corresponding AEO 2014 Reference Case projections for DFO and RFO to electricity generators in New England. As indicated in Exhibit 3-6, these projections indicate that DFO will be competitive with natural gas for electric generation in the winter months from 2015 through 2017. However, DFO is not projected to be competitive in the mid- to long-term, once additional pipeline capacity comes into service and natural gas basis to New England drops to levels seen prior to 2012.

Exhibit 3-6. Projected wholesale gas costs in New England vs. DFO and RFO



3.4.2 Forecast Prices of Coal

The AEO 2015 Reference Case assumes that coal in New England will remain unchanged in real term from the current levels. We consider this reasonable. The U.S. has substantial coal resources and coal prices have been relatively stable over a long time period without the volatility seen in oil and natural gas prices. While coal at the mine mouth is relatively cheap on an energy basis, it is expensive to transport and to burn. Coal is more expensive in New England because of the transportation costs, and represents a smaller fraction of annual electric generation in New England than most other parts of the U.S.

Coal demand is also unlikely to increase because of the age of existing coal-fired generation plants, various environmental concerns and anticipated retirements of coal-fired generation in many parts of the United States and specifically in New England. We use plant-specific actual coal prices as reported by SNL Energy for 2015. These coal prices in $/MMbtu are:

Brayton Point 1-3	$2.35
Bridgeport Harbor 3	$2.46
Merrimack 1-2	$4.04
Schiller 4&6	$3.81

3.5 Avoided Costs of Petroleum Prices in the Residential, Commercial, and Industrial Sectors

The AEO 2014 Reference Case provides forecasts of prices for distillate, residual fuel oil and propane in the residential, commercial, and industrial sectors in New England. The retail price of each fuel in each sector of a given state can be separated into two major components. The first component is the price of the underlying resource, crude oil. The second component is a margin, or the difference between the price of each fuel at the retail level and the crude oil price. The margin represents the aggregate unit costs of the refining process, distribution, and taxes attributed to the particular fuel by sector and state. As in AESC 2013, we developed our forecast of prices for fuels in each sector in two basic steps:

- First, we calculated the price margin implicit in the AEO 2013 forecast of the New England regional price for each fuel, expressed as a ratio to the crude oil price, and compared it to the historical price margin, calculated from historical price data.
- Second, we derived regional forecasts of New England prices for each fuel by multiplying our forecast of the crude oil price by the above product price ratios.

The AESC 2015 forecast of regional prices of petroleum and related products by sector is based on the following approaches:

- **No. 2 and 6 Fuel Oil:** The AEO 2015 Reference Case forecast of product prices for New England by sector were adjusted by the ratio of AESC 2015 crude oil forecast to AEO 2013 crude oil forecast.
- **No. 4 Oil:** We did not prepare a projection. No. 4 is a blend of distillate and residual and we had no data on the relative proportions of that blend.
- **B20:** The AEO 2015 forecast is based on the average ratio of B20 diesel and diesel prices in New England, as well as a review of data on bioheat available from heating oil dealer websites. We did not prepare a projection for B5 as that blend does not appear to have a material market share.

Since oil prices did not show meaningful variations by month or season, we did not develop monthly or seasonal price variations for petroleum products. Storage for petroleum products is relatively inexpensive and this also tends to smooth out variations in costs relative to market prices. For these reasons our forecast does not address volatility in the prices of these fuels.

3.5.1 Weighted Average Avoided Costs by Sector Based on Regional Prices

We developed weighted average costs of avoided petroleum-related fuels by sector by multiplying our projected regional prices for each fuel and sector by the relative quantities of each petroleum-related fuel that AEO 2015 projects will be used in that sector. The relative quantity of each petroleum-related fuel that AEO 2015 projects for each sector, expressed as percentages, will be presented in Appendix D. The resulting weighted average costs of avoided petroleum-related fuels by sector will also be presented in Appendix D.

3.5.2 Prices by State by Sector

To determine if there were material differences by state in the historical prices for any of these fuels in these sectors, we analyzed the actual prices by sector in each state from 1999 through 2012 using data from the EIA State Energy Data System (SEDS). This is the most complete and consistent source of state-level energy prices.

Given the uncertainty associated with future quantities of fuel use by state by sector, future policies on fuel taxes by state by sector, and other uncertainties, we concluded that no further precision would be obtained from an estimate of avoided petroleum-related fuel prices by sector by state.

3.6 Avoided Costs of Other Residential Fuels

AESC 2015 developed forecast avoided costs for propane, kerosene, cordwood and wood pellets.

- The avoided costs for propane are based on the AEO 2014 Reference case forecast and the AESC 2015 crude oil price forecast.
- The avoided costs for kerosene are based on AESC 2015 forecast of distillate in the residential sector and the historical average ratio between the price of kerosene and the price of distillate from EIA SEDS data.
- The avoided costs for cordwood and for wood pellets are based on AESC 2015 forecast of distillate in the residential sector, the historical average ratio between the price of cord wood and the price of distillate in the residential sector from EIA SEDS data, and the price of pellets versus of cord wood as reported by state agencies in Vermont, New Hampshire and Maine.

Exhibit 3-7 presents the AESC 2015 fifteen year levelized avoided costs for selected fuels in the residential and commercial sectors, as well as the comparable levelized costs from AESC 2013.

Exhibit 3-7. Avoided Costs of Retail Fuels (15 year Levelized, 2015$) - AESC 2015 vs. AESC 2013

Sector	Residential						Commercial	
Fuel	No. 2 Distillate	Propane	Kerosene	BioFuel	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)
AESC 2015 Levelized Values (2015$/MMBtu); 2016-2030	$ 19.20	$ 18.35	$ 20.94	$ 18.68	$ 6.80	$ 7.74	$18.70	$16.47
AESC 2013 Levelized Values (2015$/MMBtu); 2014-2028	$ 28.89	$ 29.16	$ 31.73	$ 30.35	$ 10.47	$ 17.45	$ 27.78	$ 16.80
AESC 2015 vs AESC 2013, % higher (lower)	-33.5%	-37.1%	-34.0%	-38.5%	-35.0%	-55.6%	-32.7%	-1.9%

Chapter 4: Embedded and Non-Embedded Environmental Costs

4.1 Introduction and Overview

This chapter discusses the values associated with mitigating the most significant airborne pollutants created by: 1) the combustion of natural gas, fuel oil, coal, and biomass for the purpose of electricity generation; and 2) the combustion of natural gas, fuel oil, wood, and kerosene for use in commercial, industrial, and residential sectors. These values, or environmental costs, have two components, referred to as "embedded" and "non-embedded" environmental costs.

Embedded environmental costs are environmental costs that are reflected in the market prices of fuels and/or of electric energy produced fuels. AESC 2015 embeds environmental costs explicitly as pollutant allowance prices which are in turn reflected in marginal electricity prices, i.e., avoided market costs. AESC 2015 also embeds environmental costs implicitly through its assumptions regarding the operating characteristics of generating units, and the characteristics of new units added to meet capacity. Those assumptions reflect the impact of environmental regulation on the investment and operating decisions by owners of generating units, e.g., to limit emissions through retrofits or to retire units.

Non -embedded environmental costs are environmental costs imposed on society by the use of these fuels, but not reflected in market prices.

This chapter discusses embedded and non-embedded environmental costs in five major sections:

- **Environmental Regulations: Embedded Costs:** This section identifies avoided costs associated with expected and existing NO_x, SO_2, and CO_2 regulations. These costs are embedded in the assumptions used by our electric market simulation model (pCA) to calculate avoided electric energy costs. Compared to the AESC 2013 assumptions, the AESC 2015 estimates for NO_x and CO_2 are lower by approximately 65% and 14% respectively. The estimate for SO_2 is essentially the same.
- **Non-Embedded Environmental Costs:** For AESC 2015, we anticipate that the non-embedded CO_2 cost will continue to be the dominant non-embedded environmental cost associated with marginal electricity generation in New England. This cost is not included in AESC 2015 avoided cost calculations for electric energy or other fuels. We provide recommendations for PAs to apply avoided non-embedded CO_2 costs in their evaluations of EE programs.
- **Value of Mitigating Significant Pollutants:** This section identifies and describes the most significant pollutants associated with electricity generation, end-use natural gas, and end-use fuel oil and other fuels. The section then provides the value associated with

mitigating those pollutants for end-use natural gas, fuel oil, and other fuels based on AESC 2015 NO_x, SO_2, and CO_2 emissions allowance prices per short ton (embedded costs), and the AESC 2015 recommended CO_2 (non-embedded) abatement cost. For end-use natural gas, fuel oil, and other fuels, the value of mitigating significant pollutants is non-embedded.

- **Discussion of Non-Embedded NO_x Costs:** This section addresses non-embedded NO_x costs, at the request of the Study Group, in order to increase awareness. Please note that we are *not* recommending that PAs use an additional non-embedded NO_x value beyond the embedded allowance prices discussed in this chapter. Instead, we recommend a methodology consistent with AESC 2013.
- **Compliance with State-Specific Climate Plans:** this section describes our review of state-specific regulations or climate plans that would directly impact the cost of electric generation over the study period.

Emissions from hydraulic fracturing are covered in Chapter 2.

4.2 Environmental Regulations: Embedded Costs

For all fuels, we estimate the embedded value associated with the mitigation of NO_x, SO_2, and CO_2 based on the allowance prices per short ton of emissions described and presented in this section. In addition, future environmental regulations will impact generator expenses, outages, and retirement decisions, which are inputs into our simulation model.

4.2.1 Cost of Complying with Existing and Expected SO_2, NO_x, and CO_2 Regulations

AESC 2015 applies the per-unit costs of complying with regulations governing the emissions of SO_2, NO_x and CO_2 in the pCA electricity market model simulations. pCA includes the unit costs associated with each of these emissions when calculating the generator offer prices used to make commitment and dispatch decisions. In this way, AESC 2015 projects market prices that reflect, or “embed,” the compliance costs for each type of emission, excluding mercury.

The per-unit compliance costs assumed for each pollutant are presented in Exhibit 4-1. NOx allowance prices have fallen considerably since AESC 2013, from approximately $28 per ton to approximately $10 per ton in AESC 2015. At $1.11 per ton, the 2015 SO_2 prices are little changed from the $0 AESC 2013 value. The 15-year levelized value of the embedded avoided cost of carbon compliance for AESC 2015 is 14 percent lower than AESC 2013 (2015$), i.e., $15.68/ton versus $20.42/ton. This decrease is primarily due to a slightly lower forecast of Regional Greenhouse Gas Initiative (RGGI) prices through 2020, reliance on year 2029 results from a regional CO_2 price forecast for 2021 onward based on a simulation of EPA’s proposed Clean Power Plan (CPP) and an assumed linear transition from the RGGI 2020 value to the 2029 CPP forecast value.

Exhibit 4-1. Emission Allowance Prices per Short Ton (Constant 2015$ and Nominal Dollars)

	NOx		SO2		CO2	
Year	2015$	Nominal	2015$	Nominal	2015$	Nominal
2015	10.00	10.00	1.11	1.11	6.28	6.28
2016	10.00	10.17	1.11	1.13	7.26	7.38
2017	10.00	10.16	1.11	1.15	7.87	8.15
2018	10.00	10.57	1.11	1.17	8.47	8.95
2019	10.00	10.78	1.11	1.19	9.32	10.05
2020	10.00	11.00	1.11	1.22	10.16	11.18
2021	10.00	11.22	1.11	1.24	12.54	14.07
2022	10.00	11.44	1.11	1.27	14.92	17.07
2023	10.00	11.67	1.11	1.29	17.30	20.18
2024	10.00	11.90	1.11	1.32	19.67	23.42
2025	10.00	12.13	1.11	1.34	22.05	26.74
2026	10.00	12.36	1.11	1.37	24.43	30.18
2027	10.00	12.59	1.11	1.39	26.80	33.74
2028	10.00	12.82	1.11	1.42	29.18	37.42
2029	10.00	13.07	1.11	1.45	31.56	41.23
2030	10.00	13.31	1.11	1.47	33.94	45.17

NO_x & SO_2 from SNL Financial. CO_2 (2015-2020) from RGGI Updated Model Rule Modeling. CO_2 (2029) from "Critical Mass: An SNL Energy Evaluation of Mass-based Compliance Under the EPA Clean Power Plan," SNL Energy. CO_2 (2021-2028): linear interpolation. CO_2 (2030): linear extrapolation.

NO_x and SO_2

The NO_x and SO_2 allowance prices are based on values provided by SNL Financial, which constitute the pCA default assumptions.[52] Since there is still considerable uncertainty about the longer term, we have kept NO_x and SO_2 prices level at constant 2015 dollar (2015$) values. For mercury, we assume no trading, and hence no allowance price.

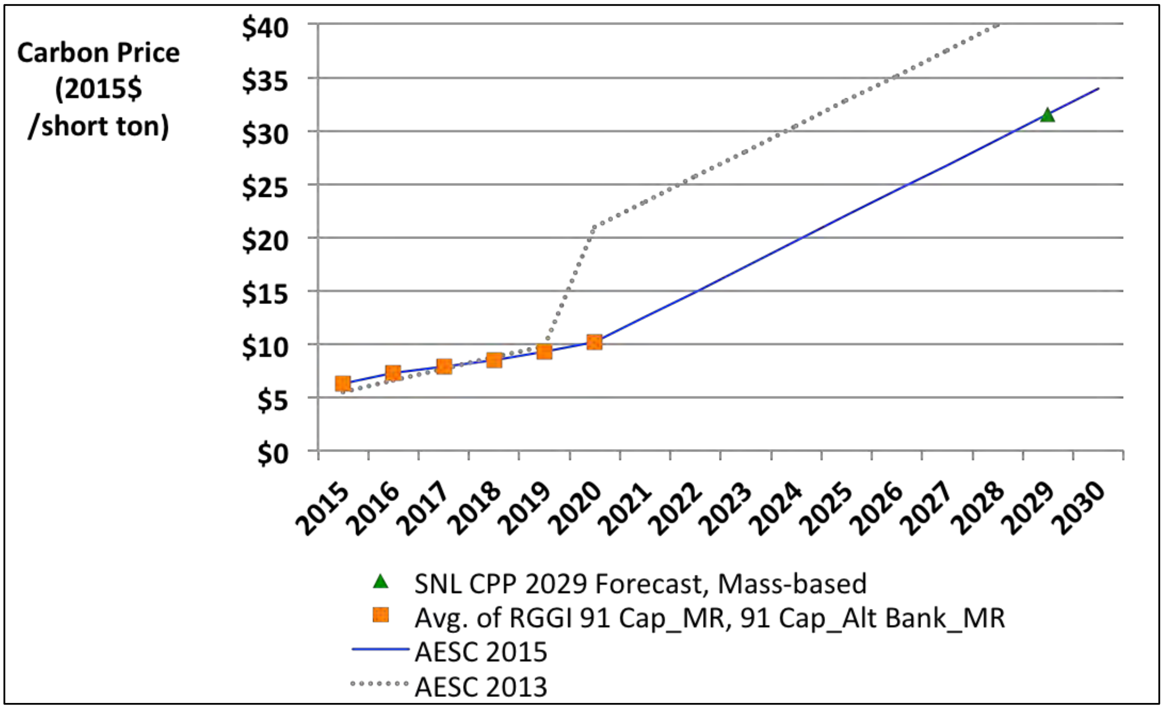
[52] The SNL values were found to be consistent with those in other sources, such as Megawatt Daily and Argus Air Daily.

CO_2

AESC 2015 assumes CO_2 regulation under the Regional Greenhouse Gas Initiative (RGGI) through 2020, and CO_2 regulation under EPA's proposed Clean Power Plan (CPP) between 2021 and 2030.

The AESC 2015 CO2 forecast is presented in Exhibit 4-2.

Exhibit 4-2 AESC 2015 Carbon Price Forecast



Our Base Case estimates of embedded CO_2 costs through 2020 are derived from RGGI allowance price forecasts through 2020. In February of 2012, the RGGI states agreed to reduce the 2014 CO_2 cap from 165 million to 91 million tons, a reduction of 45%. The cap would decline 2.5% each year from 2015 to 2020.[53] The RGGI states' analysis indicated that this would result in the allowance price rising to between approximately $4 and $6 per short ton (2010$) in 2014 and increasing to between approximately $8 and $10 per ton (2010$) in 2020, depending on the scenario. AESC 2015 uses annual prices that are the averages of those projected for the scenarios 91_Cap_Bank_MR and 91_Cap_AltBank_MR.[54]

[53] This annual reduction results in a 2020 cap value of 78.1 million short tons.

[54] RGGI IPM Analysis: Amended Model Rule, February 8, 2013, and associated IPM modeling results data. Available at: http://www.rggi.org/docs/ProgramReview/February11/. The average of the two scenarios modeled prices for 2014 (in current dollars) is very close to the RGGI December 3, 2014 auction price of $5.21.

Between 2020 and 2029, EPA has proposed that an interim standard would apply, which states or regions would be required to meet on average over the period.[55] Under the CPP as proposed, states or regions will have the option to comply with either an emissions rate-based standard, or its mass-based equivalent. Based on comments submitted by RGGI, and discussions with others following developments related to the regulations closely, we believe that compliance—at least in the RGGI states if not everywhere—is more likely to be implemented using mass-based standards, or mass-based equivalents of rate-based standards. SNL Energy has forecast allowance prices under CPP using AuroraXMP.[56] SNL modeled mass-based compliance under CPP for the RGGI region, without constraints representing the existing RGGI standards or potential extension of them. AESC uses SNL's 2029 (final CPP) value of $31 (2014$), with a linear interpolation between that and RGGI's 2020 value of $10.16 (2010$), extrapolating one year further to 2030.[57] The 2030 extrapolated value, incidentally, is approximately the same as the 2030 EPA modeled value under the rate-based standard.[58]

The sum of the CPP final (2029) goals for the RGGI states combined, in mass-equivalent terms, is 64 million short tons of CO2,[59] which is the level the RGGI cap would reach in 2028, were it to continue to decrease at the established 2014-2020 rate of 2.5% per year. Extending the 2.5% annual decrease in the RGGI cap results in a 2020-2029 average of 70 million short tons, as compared to a CPP interim standard for the RGGI states of 69 million short tons. Exhibit 4-3 shows a comparison of the RGGI cap and combined CPP goal.

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[55] SNL does not present estimates for individual years during the interim period. As discussed below, it is expected that the EPA is likely to do away with or waive the interim goals.

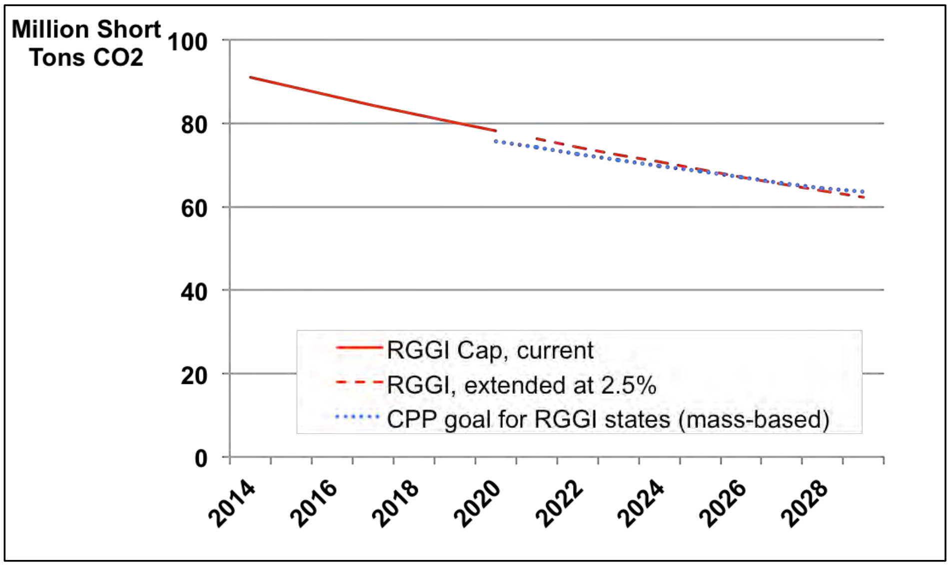
[56] "Critical Mass: An SNL Energy Evaluation of Mass-based Compliance under the EPA Clean Power Plan." A. Gelbaugh et. al, December 2014. http://www.slideshare.net/SNLFinancial/analysis-of-the-epas-clean-power-plan-on.

[57] EPA performed an analysis of example implementations of and compliance with CPP using the simulation tool IPM, developed by ICF, with five-year increments. The simulations were performed assuming compliance with the proposed state emissions rate standards, and assuming a given mix of compliance in each state using the four compliance "building blocks." Under mass-based standards, compliance costs are expected to be lower than under the equivalent rate-based standards.[57] For those reasons, and because we expect the RGGI states to elect to comply using a mass-based standard, we believe that EPA's modeled CO_2 shadow prices for a rate-based constraint are not appropriate for use as a CO_2 price trajectory in AESC.

[58] Based on EPA's IPM simulation results, CO2 shadow price for NPCC, Option 1, rate-based compliance ($34.27 in 2015$). Simulation results available at: http://www.epa.gov/airmarkets/powersectormodeling/docs/Option%201%20Regional.zip.

[59] Calculation based on data in the *Rate to Mass Translation Data File*. *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents#rate-to-mass. In this report, we focus on the proposed final CO_2 emissions standards to be achieved by 2030 under compliance "Option 1." The EPA also proposed alternative "Option 2" goals, which reflect emissions reductions that are less stringent but must be met earlier, with an interim goal set for 2020–2024 and a final goal for 2025.

Exhibit 4-3. Current and Extended RGGI Cap Compared to Sum of CPP Goals for RGGI States



Source: Based on RGGI data and data in the U.S. EPA Clean Power Plan Rate to Mass Translation Data File (see text).

4.2.2 Existing and Expected Regulations

This section summarizes the existing and expected environmental regulations that are incorporated into AESC 2015, and which are reflected in Exhibit 4-1, above.

CO2 - Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative is a cap and trade greenhouse gas program for power plants in the northeastern United States. Current participant states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Pennsylvania, Québec, New Brunswick, and Ontario are official "observers" in the RGGI process. As of March 11, 2015, 27 RGGI auctions have occurred.

RGGI is designed to:

- Limit CO_2 emissions from power plants to 2009 levels for the period 2009 – 2013, followed by a 53 percent reduction below those levels by 2020.
- Allocate a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes. Allowances allocated for consumer benefit will be auctioned and the proceeds of the auction used for consumer benefit and strategic energy purposes.

- Include certain offset provisions that increase flexibility to include opportunities outside the capped electricity generation sector.[60]

EPA Regulations—Greenhouse Gases

Greenhouse Gas Tailoring Rule

Under EPA's Greenhouse Gas Tailoring Rule, large sources of greenhouse gas emissions are subject to permitting requirements. For purposes of determining whether New Source Review applies, a "large source" is a new facility with emissions of at least 100,000 tons per year of carbon dioxide equivalent (CO_2e) or an existing facility that emits at least 100,000 tons per year CO_2e and is making modifications that would increase greenhouse gas emissions by at least 75,000 tons per year CO_2e. These sources are required to obtain permits under the New Source Review Prevention of Significant Deterioration program and therefore must install Best Available Control Technology (BACT) for greenhouse gases. In the case of a modification, to a facility that does not emit at least 100,000 tons per year CO_2e but will increase greenhouse gas emissions by 75,000 tons per year CO_2e, the BACT requirement only applies for GHG if the project triggers new source review for another criteria pollutant. Any new or existing source with emissions of 100,000 tons per year CO_2e or more must obtain a Title V operating permit.

On June 23, 2014, the U.S. Supreme Court confirmed the EPA's authority to regulate GHG emissions from new and modified stationary sources required to obtain pre-construction and operating permits for non-GHG air pollutants, but held that EPA may not require a source to obtain a pre-construction or operating permit solely on the basis of its potential GHG emissions. The decision upholds EPA's regulation of about 83 percent of stationary source GHG emissions under the PSD/Title V permitting process, because nearly all of these sources also emit significant amounts of criteria air pollutants.[61] In practice, this represents a modest change.

Greenhouse Gas New Source Performance Standards (GHG NSPS)

Under Section 111 of the Clean Air Act, EPA sets technology-based standards for new sources on a category-by-category basis. These standards are set based on the best demonstrated available technology (BDAT) and apply to all new sources built or modified following promulgation of the standard.

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[60] *See* Regional Greenhouse Gas Initiative website. Accessed November 25, 2014. Available at: http://www.rggi.org/design/program-review. Our calculation of the 2020 reduction from the 165 million ton 2009 level is as follows: (165-91*(1-0.025)^6)/165 = 53%

[61] Jennings, et al., *Supreme Court rejects premise for GHG Tailoring Rule, but largely maintains EPA's authority to set GHG emission limits*, DLA Piper Climate Change Alert (June 26, 2014). Available at: https://www.dlapiper.com/en/us/insights/publications/2014/06/supreme-court-rejects-premise/

On March 27, 2012, EPA proposed[62] NSPS for greenhouse gas emissions from new electric generating units. The standard was set at 1,000 lb CO_2e/MWh, which is equivalent to the emission rate that a combined-cycle natural gas unit can achieve. The rule also allows a unit's emissions to be averaged over 30 years to achieve an annual average emission rate of 1,000 lb CO_2e/MWh. This option allows the phase-in of CCS within the first 10 years of operation. On January 8, 2014, EPA proposed to withdraw the 2012 proposed GHG NSPS, given that new proposed requirements based on different analyses from the original proposal would establish requirements that would differ significantly from the original proposal.[63]

In September 2013, EPA released a revised 111(b) rule, New Source Performance Standards for GHGs from new sources. The proposed standards for new power plants are the first uniform national limits on CO_2 emissions by new power plants. EPA is proposing separate standards for certain natural gas-fired stationary combustion turbines, fossil fuel-fired utility boilers, and integrated gasification combined cycle (IGCC) units. All standards are in pounds of CO_2 per megawatt-hour (lb CO_2/MWh gross).[64]

Fossil Fuel-Fired Utility Boilers and IGCC Units

EPA is proposing two limits for fossil fuel-fired utility boilers and IGCC units, depending on the compliance period that best suits the unit. These limits require capture of only a portion of the CO_2 from the new unit. These proposed limits are:

- 1,100 lb CO_2/MWh gross over a one-year period, or
- 1,000-1,050 lb CO_2/MWh gross over a seven-year period

Natural Gas-Fired Stationary Combustion Units

EPA is proposing two standards for natural gas-fired stationary combustion units, depending on size. The proposed limits are based on the performance of modern natural gas combined cycle (NGCC) units. These proposed limits are:

- 1,000 lb CO2/MWh gross for larger units (> 850 MMBtu/hr)
- 1,100 lb CO2/MWh gross for smaller units (≤ 850 MMBtu/hr)

[62] 77 Fed. Reg. 22392 (April 13, 2012).

[63] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants

[64] *Ibid.*

On January 8, 2014, EPA issued a second NPRM on the proposal, and under an updated timeline announced late 2014, it intends to issue a final rule on Carbon Pollution Standards for New, Modified and Reconstructed Power Plants in summer of 2015.[65]

Almost no new coal plants are being proposed due to low gas prices, so the direct impact of Section 111(b) is currently modest. Nevertheless, the proposed rule is being litigated. It is thought that the principal purpose of challenges to Section 111(b) derives from the rule's role as a prerequisite for Section 111(d). Because Section 111(d) only applies to existing sources where there are standards of performance for new sources of the same type, invalidating Section 111(b) could also invalidate Section 111(d).[66]

Opponents question whether the proposed rule conforms to the Energy Policy Act of 2005 since the proposed rule relies on a "new technology," i.e., carbon capture and sequestration (CCS). It is unlikely for the current challenges to succeed, because the plaintiffs are seeking to stop the rulemaking while it is still underway. Future challenges are expected once the final rule is issued.

Clean Power Plan Proposed Rule

While New Source Performance Standards apply only to new facilities, Section 111(d) of the Clean Air Act requires states to develop plans for *existing* sources of any non-criteria pollutants (i.e., a pollutant for which there is no NAAQS) and non-hazardous air pollutant whenever EPA promulgates a standard for a new source. These plans are subject to EPA review and approval, similar to state implementation plans under the NAAQS program.

A draft 111(d) rule controlling GHGs from greenhouse gases existing sources was submitted on March 31, 2014, which laid out a timeline: EPA would propose standards in June 2014, EPA would finalize the standards in June 2015,[67] and states would submit SIPs to EPA in June 2016.[68]

On June 2, 2014, the EPA proposed the *Clean Power Plan* (CPP) to cut carbon emissions from existing power plants. The plan proposed to begin meaningful reductions in 2020, and to cut carbon emission from the power sector by 30 percent nationwide below 2005 levels by 2030, as well as cut particle pollution, nitrogen oxides, and sulfur dioxide by more than 25 percent as a co-benefit.[69] Under the plan,

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[65] *See* U.S. Environmental Protection Agency website. Accessed January 27, 2015. Available at: http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-carbon-pollution-standards-key-dates

[66] "Legal Challenges to Obama Administration's Clean Power Plan," Michael B. Gerrard, New York Law Journal, September 11, 2014. Available at: http://www.arnoldporter.com/resources/documents/NYLJ_Legal Challenges to Obama Administration's Clean Power Plan_09112014.pdf

[67] John Podesta, former White House Chief of Staff, is said to believe that a final rule won't be issued until late summer 2015.

[68] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

[69] President Obama and Chinese President Xi Jinping announced in November 2014 that the United States intends to set an economy-wide target of reducing CO_2 emissions by 26-28 percent below 2005 levels by 2025. This is roughly consistent with the 30% reduction from 2005 levels by 2030 proposed in the CPP.

each state has the flexibility to choose how to meet the goal using a combination of measures that reflect its particular circumstances and policy objectives. The basic formula for the state goal is a rate: CO_2 emissions from fossil fuel-fired power plants in pounds divided by state electricity generation from fossil-fuel fired power plants and certain low- or zero-emitting power sources in megawatt hours (MWh). EPA is proposing a two-part goal structure: an "interim goal" that a state must meet on average over the ten-year period from 2020-2029 and a "final goal" that a state must meet at the end of that period in 2030 and thereafter. As described above, the EPA also proposed alternative "Option 2" goals, which reflect emissions reductions that are less stringent but must be met earlier, with an interim goal set for 2020–2024 and a final goal for 2025.

Under CAA section 111(d), state plans must establish standards of performance that reflect the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER). The BSER proposed in the rule is based on a range of measures that fall into four main categories, or "building blocks," which comprise (1) improved generator operations, (2) dispatching lower-emitting generators and (3) zero-emitting energy sources and end-use energy efficiency. Only Building Block 1 is required; the others are optional. The proposed state-level goals reflect the level of reductions in CO^2 emissions and emission rates and the extent of the application of the building blocks that would be presumptively approvable in a state plan during the ramp-up to achieving the final goal.

EPA is also proposing to give states the option to convert the rate-based goal to a mass-based goal if they choose to in their state plans—something the RGGI states have heartily endorsed—and has published proposed conversion factors and methodology.[70] Adopting a mass-based goal would better allow a state or group of states to cap their CO_2 emissions and set up a trading program if they choose that option to meet the goals outlined in the proposal, and would make it easier to avoid double counting contributions of energy efficiency and renewable energy produced in one state and counted in another. EPA is only proposing goals for states with fossil fuel-fired power plants; Vermont and Washington, DC are excluded for that reason.

On October 28, 2014, EPA issued a supplemental proposal, which sets area-specific goals for Indian country and territories and provides options for meeting those goals in a flexible manner. Under a modified timeline announced in late 2014, EPA in summer 2015 would issue final rules on CPP and propose a federal plan for meeting CPP goals for public review and comment. By summer 2016, EPA will be in a position to issue a final federal plan for meeting Clean Power Plan goals in areas that do not submit plans.[71]

It is expected that the EPA is likely to do away with or waive the interim goals, not because of legal challenges, but because of significant push-back from the states. It is also possible that there will be

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[70] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents-rate-to-mass

[71] *See* U.S. Environmental Protection Agency website. Accessed January 27, 2015. Available at: http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-carbon-pollution-standards-key-dates

some adjustment to the stringency of the prescribed state-specific emissions rates. One possibility is that the final overall rate will be the same as that in the proposed rule, but the individual rates will differ from those proposed. The latter is likely because of possible changes in the way Building Block 3 (renewable energy) amounts are calculated.

Although there are current legal challenges to the proposed rule, those are unlikely to succeed because the rulemaking is still in progress, and so are not likely to delay implementation of the rule. Although future lawsuits on the final rule may ultimately be successful, they are unlikely to cause delays in implementation, which would happen only in the rare event that a court issues a stay (as happened with CSAPR). A Supreme Court case on any of the challenges would likely be decided sometime between the spring 2017 and December 2019.

Carbon Pollution Standards for Modified and Reconstructed Power Plants

On June 2, 2014, EPA proposed standards to address carbon dioxide emissions from modified and reconstructed power plants. Like the proposed Carbon Pollution Standards for newly constructed power plants, the proposed Carbon Pollution Standards for modified and reconstructed power plants are also set under the authority of Clean Air Act Section 111(b). A modification, according to the rule, is "any physical or operational change to an existing source that increases the source's maximum achievable hourly rate of air pollutant emissions." A reconstructed source is "a unit that replaces components to such an extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable facility."[72]

The fact that these provisions of Section 111(b) do not rely on new technology may be what ultimately enables the final rule to survive challenges aimed the new source provisions' reliance on CCS.

EPA Regulations—Other Emissions

National Ambient Air Quality Standards

National Ambient Air Quality Standards (NAAQS) set maximum air quality limitations that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are stationed in various cities throughout the United States, or through air quality dispersion modeling. States with areas found to be in "nonattainment" of a particular NAAQS are required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are achieved and maintained. The U.S. Environmental Protection Agency (EPA) has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10 micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

[72] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www2.epa.gov/carbon-pollution-standards/proposed-carbon-pollution-standards-modified-and-reconstructed-power

In nonattainment areas, pollutant sources must comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT) to bring the areas into attainment of the NAAQS. New major sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER) and obtain emission offsets.

EPA is currently in the process of drafting new, more stringent NAAQS for SO_2, PM2.5, and ozone.

- On June 22, 2010, EPA revised[73] the standard for SO_2 by establishing a new 1-hour standard at a level of 75 parts per billion (ppb) in place of the existing annual and 24-hour standards for SO_2. EPA on July 25, 2013 designated parts of 16 states as nonattainment for the 2010 SO_2 standard, and the designations were finalized in August 2013. For New England, parts of three counties in central New Hampshire were designated, and New Hampshire revised its state implementation plan (SIP) accordingly.[74] States have until October 2018 to attain the NAAQS.[75] On April 17, 2014, EPA issued a proposed rule that would allow state and local air agencies to use air quality monitoring or modeling to determine whether areas meet the 2010 air quality standards.[76]
- On December 14, 2012, EPA strengthened the annual PM2.5 standard from 15 µg/m3 to 12 µg/m3, and retained the current 24-hour standard at 35 µg/m3. On April 25, 2014, in response to a decision of the D.C. Circuit Court regarding implementation of the PM2.5 standard, EPA classified as "moderate" nonattainment areas for the 1997 and 2006 fine particle pollution standards and set December 31, 2014 as the deadline for states to submit remaining implementation plan requirements, outlining how they will reduce pollution to meet the standard by 2020.[77]
- In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA's panel of science advisors, it would reconsider the 75 ppb standard. In 2010, EPA proposed lowering the 8-hour ozone standard from 75 ppb to between 60 and 70 ppb, and on September

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[73] 75 Fed. Reg. 35520 (June 22, 2010)

[74] *See* New Hampshire Department of Environmental Services website. Accessed December 2, 2014. Available at: http://des.nh.gov/organization/divisions/air/do/sip/sip-revisions.htm#so2

[75] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www.epa.gov/airquality/sulfurdioxide/implement.html

[76] *Ibid.*

[77] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www.epa.gov/pm/actions.html

2, 2011, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the regular 5-year NAAQS review cycle. On November 25, 2014, the EPA proposed lowering the standard to within a range of 65 to 70 ppb. EPA projections show the vast majority of U.S. counties would meet the proposed standards by 2025 just with the rules and programs now in place or under way. States with nonattainment areas would have until 2020 to late 2037 to meet the proposed health standard. The agency will issue a final decision by Oct. 1, 2015.[78]

Cross State Air Pollution Rule

The Cross State Air Pollution Rule (CSAPR), which replaces the 2005 Clean Air Interstate Rule (CAIR), was finalized in 2011, establishing the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. CSAPR requires a total of 28 states to reduce annual SO_2 emissions, annual NO_X emissions and/or ozone season NO_X emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle NAAQS. The rule targets electric generating units, and uses a cap and-trade approach to limit each state to emissions below a level that significantly contributes to non-attainment in downwind states.

On August 21, 2012, the U.S. Court of Appeals for the District of Columbia vacated CSAPR by leaving the CAIR requirements in place. The EPA and various environmental groups petitioned the Supreme Court of the United States to review the D.C. Circuit Court's decision on CSAPR. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing the D.C. Circuit decision. Following the remand of the case to the D.C. Circuit, EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted EPA's request. Accordingly, CSAPR Phase 1 implementation is now scheduled for 2015, with Phase 2 beginning in 2017.[79] While CSAPR-related litigation remains pending, none is considered a threat to the rule.

None of the New England states have obligations under CSAPR, although a replacement or follow-up rule, expected to be developed during 2016-2017 for implementation in 2018-2019, could affect sources in Connecticut or Massachusetts.

Regional Haze Rules

One of the national goals set out in the Clean Air Act is reducing existing visibility impairment from human-made air pollution in all "Class I" areas (e.g., most national parks and wilderness areas).[80] EPA's

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[78] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www.epa.gov/groundlevelozone/actions.html

[79] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www.epa.gov/airtransport/CSAPR/

[80] 42 U.S.C. § 7491(a)(1)

Regional Haze Rule—issued in 1999, and revised in 2005—requires states to create plans to significantly improve visibility conditions in Class I areas with the goal of achieving natural background visibility conditions by 2064. These requirements are implemented through state plans with enforceable reductions in haze-causing pollution from individual sources and with other measures to meet "reasonable further progress" milestones.[81] The first progress milestone is 2018.

A key component of this program is the imposition of air pollution controls on existing facilities that impact visibility in Class I areas. Specifically, the rules require installation of "best available retrofit technology" (BART) that is developed for such facilities on a case-by-case basis. In addition, EPA's BART determinations specify particular emission limits for each BART-eligible facility. EPA evaluates BART for the air pollutants that impact visibility in our national parks and wilderness areas—namely SO_2, PM, and NO_x. Under the Clean Air Act, states develop Regional Haze requirements, but EPA approves state plans for compliance. If EPA finds the plans are not consistent with the Clean Air Act, it adopts a federal plan with BART and reasonable progress requirements. Affected facilities must comply with the BART determinations as expeditiously as practicable but no later than five years from the date EPA approves the state plan or adopts a federal plan.[82]

Mercury and Air Toxics Standards (MATS)

In 2000, EPA determined it was appropriate and necessary to regulate toxic air emissions (or hazardous air pollutants) from steam electric generating units. As a result, EPA adopted strict emission limitations for hazardous air pollutants that are based on the emissions of the cleanest existing sources.[83] These emission limitations are known as Maximum Achievable Control Technology (MACT). The final MATS rule, approved in December 2011, sets strict stack emissions limits for mercury, other metal toxins, other organic and inorganic hazardous air pollutants, as well as acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016.

On March 28, 2013, the EPA finalized updates to certain emission limits for new power plants under MATS. This includes emission limits for mercury, PM, SO_2, acid gases and certain individual metals. On

[81] 40 C.F.R. §51.308-309

[82] EPA's regulations allow certain states in the "Grand Canyon Visibility Transport Region" to participate in an SO_2 trading program in lieu of adopting source-specific SO_2 BART requirements, if the trading program will result in greater reasonable progress toward attaining the national visibility goal than source-specific BART. Although nine states were originally eligible to participate, today only three states are opting to participate in this program – New Mexico, Utah, and Wyoming. These states agreed to a gradually declining cap on SO_2 emissions from all emission sources. If the declining caps are exceeded in any year, then even greater SO_2 emission reductions have to be achieved—although the reductions can be met through emissions trading, rather than imposition of specific emission limitations on any one facility. This program is called the Backstop Trading Program.

[83] Clean Air Act §112(d)

November 7, 2014, EPA finalized an action reconsidering the provisions applicable during periods of startup and shutdown under MATS and Utility New Source Performance Standards (Utility NSPS).[84]

According to ISO New England, approximately 7.9 GW of existing coal- and oil-fired capacity in the region are subject to MATS.[85] The ISO considers less than 1 GW of affected fossil capacity in New England to be at risk for retirement because of an inability to comply with MATS, because most remaining coal-fired generators already are retrofitted with needed controls to comply with state air toxics regulations, and most remaining larger oil-fired generators in New England are only subject to *de Minimis* work practice standards under MATS and not required to add any emission control devices.

MATS continues to face litigation, notably before the U.S. Supreme Court. The Court, on November 25, 2014, accepted three petitions, consolidated them and granted review: *Michigan v. EPA*, *Utility Air Regulatory Group v. EPA*, and *National Mining Association v. EPA*. The Court will consider "Whether the Environmental Protection Agency unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities." The implications of the case reach potentially beyond MATS.[86]

Coal Combustion Residuals Disposal Rule

Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments. The risk associated with wet storage of coal combustion residuals (CCR) was dramatically revealed in the catastrophic failure of the ash slurry containment at the Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River.

On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. The current rulemaking is 30 years overdue. If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system would apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would implement minimum requirements for dam safety at impoundments. For Subtitle C, requirements will go into effect in authorized states when the state adopts the rule. Timing will vary from state to state. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install

[84] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://www.epa.gov/airquality/powerplanttoxics/actions.html,

[85] ISO New England, *2014 Regional System Plan* (hereinafter "RSP2014"), November 6, 2014. Available at: http://www.iso-ne.com/static-assets/documents/2014/11/rsp14_110614_final_read_only.docx.

[86] Lyle Denniston, *Court to rule on disability rights, mercury pollution*, SCOTUSblog (Nov. 25, 2014, 1:39 PM), http://www.scotusblog.com/2014/11/court-to-rule-on-disabiity-rights-mercury-pollution/

liners, and require standards for long-term stability and closure care. For Subtitle D, the rule would be effective six months after promulgation.

The EPA is currently evaluating which regulatory pathway will be most effective in protecting human health and the environment. In 1999, EPA released a series of technical papers to Congress documenting cases in which damages are known to have occurred from leakages and spills from coal ash impoundments.[87] In the current proposed rule, the EPA recognizes a substantial increase in the types and quantities of potentially toxic CCR caused by air pollution control equipment.

Use of more advanced air pollution control technology reduces air emissions of metals and other pollutants in the flue gas of a coal-fired power plant by capturing and transferring the pollutants to the fly ash and other air pollution control residues. The impact of changes in air pollution control on the characteristics of CCRs and the leaching potential of metals is the focus of ongoing research by EPA's Office of Research and Development.[88] EPA has not yet set a date for issuance of a final rule.

<u>Steam Electric Effluent Limitation Guidelines</u>

Following a multi-year study of steam-generating units across the country, EPA found that coal-fired power plants are currently discharging a higher-than-expected level of toxic-weighted pollutants into waterways. Current effluent regulations were last updated in 1982 and do not reflect the changes that have occurred in the electric power industry over the last thirty years, and do not adequately manage the pollutants being discharged from coal-fired generating units. Coal ash ponds and flue gas desulfurization systems used by such power plants are the source of a large portion of these pollutants, and are likely to result in an increase in toxic effluents in the future as environmental regulations are promulgated and pollution controls are installed. On April 19, 2013, EPA signed a notice of proposed rulemaking that would strengthen existing controls on discharges, and a proposed rule was published on June 7, 2013. The public comment period closed on September 20, 2013. EPA is under a court order to issue a final action no later than September 30, 2015. New requirements will be phased in over 2017 to 2022.[89]

The proposal sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. Under the most stringent preferred regulatory option, EPA's projects no plants will close and at most a few units will retire. Under the most stringent preferred regulatory

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[87] EPA. March 15, 1999. Technical Background Document for the Report to Congress on Remaining Wastes from Fossil Fuel Combustion: Potential Damage Cases. http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ffc2_397.pdf

[88] 75 Fed. Reg. 35139 (June 21, 2010).

[89] *See* U.S. Environmental Protection Agency website. Accessed December 2, 2014. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/proposed.cfm

option, EPA projects national average prices to increase minimally by only 0.025 cents/KW-hr, or 0.27 percent.[90]

Clean Water Act Cooling Water Intake Structure Rule

On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.[91] Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The rule provides that:

- Existing facilities that withdraw more than two million gallons per day are subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day are required to conduct an entrainment characterization study to establish a "best technology available" for the specific site.

EPA released a final rule for implementation of Section 316(b) of the Clean Water Act on May 19, 2014. The final rule became effective October 14, 2014, and requirements will be implemented in NPDES permits as they are renewed. The rule, including design enhancements and operational requirements to reduce impingement mortality and new requirements to protect threatened and endangered species and critical habitats federally listed and designated under the *US Endangered Species Act*, will be implemented by delegated states in New England, and EPA anticipates most retrofits occurring between 2018 and 2022.[92] According to ISO New England, as much as 12.1 GW of existing fossil fuel and nuclear capacity in New England may need cooling water intake structure modification, and 5.6 GW of facilities with larger water withdrawals of once-through cooling systems will need to prepare and submit entrainment characterization reports by 2018.[93]

As of October 2014, the rule is being litigated in the 4th Circuit Court of Appeals (consolidating six petitions from other circuits). Environmental advocates challenged provisions for control technology flexibility and discretion, while industry narrowly challenged the new unit criteria as contradictory.[94]

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[90] *Ibid.*

[91] 33 U.S.C. § 1326.

[92] RSP2014.

[93] *Ibid.*

[94] *Cooling Water Intake Structure Coalition v. EPA*, Docket No. 14-1931.

4.2.3 Impact of Energy Efficiency Programs on CO_2 Emissions under a Cap and Trade Regulatory Framework

With CO_2 emissions regulated under a cap and trade system, as assumed in this market price analysis, it is conceivable that a load reduction from an energy efficiency program will not lead to a reduction in the amount of total system CO_2 emissions. The annual total system emissions for the affected facilities in the relevant region are, after all, capped. In the analysis documented in this report, the relevant cap and trade regulation is the RGGI for the period 2015 to 2020, and thereafter an assumed continuation of that regional cap and trade system (perhaps with other states joining), modified as needed to bring about CPP compliance in the member states. There are, however, a number of reasons why an energy efficiency program could nonetheless result in CO_2 emission reductions. Specifically:

- A reduction in load that reduces the cost (marginal or total cost) of achieving an emissions cap can result in a decision to tighten the cap. This is a complex interaction between the energy system and political and economic systems, and is difficult or impossible to model, but it's reasonable to assume the dynamic exists.
- Specific provisions in RGGI provide for a tightening or loosening of the cap (via adjustments to the reserve provisions that are triggered at different price levels). It is plausible that those provisions can be modified as needed to ensure compliance with the CPP as proposed.
- It is also possible that energy efficiency efforts will be accompanied by specific retirements or allocations of allowances that would cause them to have an impact on the overall system level of emissions (effectively tightening the cap).
- To the extent that the cap and trade system "leaks" outside of its geographic boundaries, one would expect the benefits of a carbon emissions reduction resulting from an energy efficiency program to similarly "leak." That is, a load reduction in New York could cause reductions in generation (and emissions) at power plants in New York, Pennsylvania, and elsewhere. Because New York is in the RGGI cap and trade system, the emissions reductions realized at New York generating units may accrue as a result of increased sales of allowances from New York to other RGGI states. Since Pennsylvania is not in the RGGI system, however, the emissions reductions at Pennsylvania generating units would be true reductions attributable to the energy efficiency program.

The first three of these points, above, would also apply to a future CO_2 cap and trade program which expands the RGGI footprint and is designed to comply with the CPP. The fourth point, regarding leakage and boundaries, would apply as well in an expanded cap and trade footprint, but to a lesser extent the larger the footprint is.

4.3 Non-Embedded Environmental Costs

Non-embedded costs are impacts from the production of a good or service that are not reflected in price of that good or service, and are not considered in the decision to provide that good or service.[95] Air pollution generated in the production of electricity is a classic example of a non-embedded cost: pollutants released from a power plant impose health impacts on a population, cause damage to the environment, or both. In this example, health impacts and ecosystem damages not reflected in the price of electricity and not considered in the power plant owner's decision of how much electricity to provide are "non-embedded," whereas adverse impacts that are reflected in the market price of electricity (e.g., through regulation) and are considered in decisions regarding production are "embedded."

For AESC 2015, the non-embedded carbon cost continues to be the dominant non-embedded environmental cost associated with marginal electricity generation in New England. This is the case for two main reasons. First, regulations to address the greenhouse gas emissions responsible for global climate change have yet to be implemented with sufficient stringency to reduce carbon emissions, particularly in the United States.[96] The damages from the EPA's criteria air pollutants are relatively bounded, and to a great extent embedded, as a result of existing regulations. In contrast, global climate change is a problem on an unprecedented scale with far-reaching and potentially catastrophic implications.

Second, New England avoided electric energy costs over the study period are dominated by natural gas-fired generation, which has minimal SO_2, mercury, and particulate emissions, as well as relatively low NO_x emissions.

4.3.1 History of Non-Embedded Environmental Cost Policies in New England

In the 1980s and 1990s, several New England states had proceedings dealing with non-embedded costs that influence current utility planning and decision-making.[97] In Massachusetts, dockets DPU 89-239 and 91-131 served as models for other states. Docket DPU 89-239 was opened to develop "Rules to Implement Integrated Resource Planning" and included the determination and application of non-embedded environmental cost values. This docket adopted a set of dollar values for air emissions, including a CO_2 value of $38 per ton of CO_2 (in 2015 dollars).[98] Docket DPU 91-131 examined

[95] In economics, a non-embedded impact can be positive (a non-embedded benefit) or negative (a non-embedded cost); in this discussion we are focusing on negative impacts (non-embedded costs).

[96] On April 17, 2009; EPA issued a proposed finding that concluded that greenhouse gases posed an endangerment to public health and welfare under the Clean Air Act ("Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" 74 Fed. Register 78: 18886–18910). This proposed finding initiates the process of potentially regulating greenhouse gases as an air pollutant. http://epa.gov/climatechange/endangerment.html

[97] A more detailed description of the history of electricity generation environmental externalities and policies in New England may be found in AESC 2007 (p. 7-6–7-8).

[98] Exhibit DOER-3, Exhibit. BB-2, p. 26. $22 in 1989 dollars.

environmental costs to develop recommendations of various approaches for quantifying the non-embedded CO_2 value. The Department of Public Utilities' (DPU) Order in Docket DPU 91-131 was noteworthy for its foresight regarding climate change, albeit optimistic about the timing of the adoption of climate change regulations in the U.S.[99] Based on information in the record, the Department reaffirmed the CO_2 value it had adopted in the previous case, $38 per ton (in 2015 dollars).

In May 2014, the Department of Environmental Protection (DEP) and the Department of Energy Resources (DOER) filed a joint petition with the Massachusetts DPU requesting the DPU to commence a proceeding to determine whether the existing method of calculating the costs (associated with GHG emissions) to comply with the Global Warming Solutions Act (GWSA), should be replaced by the marginal abatement cost curve method.[100] The matter, discussed further below in Section 4.6, is still pending before the DPU.

4.3.2 Estimating Non-Embedded CO_2 Costs

Setting a Threshold for Global CO_2 Emissions

The level of global CO_2 emissions thought to be consistent with avoiding the most serious forms of climate damage is essentially unchanged since AESC 2011.[101] Sustainability targets for CO_2 equivalent concentrations in the atmosphere are roughly 350 to 450 ppm,[102] consistent with an approximately 50 percent chance of limiting the change in the average global temperature to 2°C above pre-industrial levels.[103] The Copenhagen Agreement, drafted at the 15th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in 2009, recognizes the scientific view that in order to prevent the more drastic effects of climate change, the increase in global temperature should be limited to no more than 2°C.[104]

The Intergovernmental Panel on Climate Change (IPCC 2014, Table SPM.1) indicates that reaching concentrations of 430 to 480 ppm CO_2 equivalent, in order to limit temperature change to between 1.5 °C to 1.7 °C above pre-industrial levels by the end of the century will require a reduction in 2050 global

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[99] AESC 2009 provides more detail about the Massachusetts DPU Order in Docket DPU 91-131.

[100] Massachusetts Department of Public Utilities, Docket No. 14-86, May 16, 2014.

[101] AESC 2011 Section 6.6.4.1 page 6-97.

[102] According to IPCC, "Only a limited number of individual model studies have explored levels below 430 ppm CO_2eq… Assessing this goal is currently difficult because no multi-model studies have explored these scenarios." *See* IPCC, 2014: Summary for Policymakers, In: Climate Change 2014, Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press. (Hereinafter, "IPCC 2014"). The information and analysis presented here therefore focuses on the 450 ppm target.

[103] Ackerman and Stanton (2013) *Climate Economics: The State of the Art*. Routledge: NY.

[104] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

CO_2 emissions of 41 to 72 percent below 2010 emissions levels. To accomplish such stabilization, the U.S. and other industrialized countries would have to reduce greenhouse gas emissions on the order of 80 to 90 percent below 1990 levels, and developing countries would have to achieve reductions from the baseline increase in emissions caused by improvements in the standard of living as soon as possible (den Elzen and Meinshausen, 2006).

In the U.S., several states have adopted state greenhouse gas abatement targets of 50 percent or more reduction from a baseline of 1990 levels or then-current levels by 2050 (Arizona, California, Connecticut, Florida, Illinois, Maine, Massachusetts, Minnesota, New Hampshire, New Jersey, New Mexico, Oregon, Vermont, and Washington).[105] In Massachusetts, the GWSA, signed into law by Governor Patrick in August 2008, calls for initial reductions in greenhouse gas emissions of between 10 percent and 25 percent below 1990 levels by 2020.[106] The *Massachusetts Clean Energy and Climate Plan for 2020* (CECP), released on December 29, 2010 by the Massachusetts Executive Office of Energy and Environmental Affairs, sets out policies, with associated emissions reductions, necessary to meet the 2020 target of 25 percent below 1990 levels.[107] In early January 2015, the Massachusetts Department of Environmental Protection ("Mass DEP") published a proposed "Clean Energy Standard" (CES) regulation for public comment. A Massachusetts CES would implement one of the strategies in the CECP, and providing a long-term incentive to ensure ongoing progress toward reducing greenhouse gas emissions by 80 percent by 2050.[108]

Methods to Monetize Non-Embedded CO_2

Several different methods are available to monetize environmental costs. These include "damage cost" approaches that seek to assign a value to damages associated with a particular pollutant, and "control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant. For the same reasons outlined in AESC 2013, AESC 2015 recommends using the control cost approach to estimate non-embedded CO_2 costs for the study period.

Damage Cost Approach: The Social Cost of Carbon

Damage cost methods generally rely on travel costs, hedonic pricing, or contingent valuation to assign values in the absence—by definition—of market prices for non-embedded impacts. These are forms of "implied valuation," asking complex and hypothetical survey questions, or extrapolating from observed behavior, to impute a price to something that is never bought or sold in a market. For example, data on how much people will spend on travel, subsistence, and equipment on fishing can be used to measure

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105 Center for Climate and Energy Solutions, "A Look at Emissions Targets," http://www.c2es.org/what_s_being_done/targets

106 Massachusetts G.L. c. 21N

107 http://www.mass.gov/eea/docs/eea/energy/2020-clean-energy-plan.pdf

108 "Summary of Proposed MassDEP Regulation: Clean Energy Standard (310 CMR 7.75)," Available at: http://www.mass.gov/eea/docs/dep/air/climate/ces-fs.pdf. Additional information available at http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/ces.html.

the value of those fish, and the value of *not* killing fish with waterborne pollution. Even human lives sometimes have been valued based on wage differentials for jobs that expose workers to different risks of mortality. Comparing the difference in wages between two jobs—one with higher hourly pay rate and higher risk than the other—can serve as a measure of the compensation that someone is "willing to accept" in order to be exposed to a life-threatening risk and, by analogy, as a controversial estimate of the value of life itself.

Valuation of the societal damages caused by the emission of an additional ton of CO_2—a measure often called the "social cost of carbon"—typically combines cost estimates, using a variety of implied valuation techniques, for numerous damages from climate change that are expected around the world. In 2010, the U.S. government began to include a social cost of carbon in the valuation of federal rulemakings with the goal of accounting for the damages resulting from climate change, defined as "an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year."[109] A range of four social cost of carbon values was initially calculated by the Interagency Working Group on the Social Cost of Carbon (the "Working Group"), a group composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others.

The Working Group's estimates, presented in Exhibit 4-4, seek to represent the range of social cost of carbon values for three discount rates as well as the high-cost tail-end of the uncertain distribution of impacts in 2015 dollars per short ton CO_2.[110] It is important to note that social cost of carbon values represent the damages associated with an incremental increase in CO_2 emissions *in a given year*; for this reason, they are time-dependent and are expected to increase in future years as atmospheric concentrations of CO_2 increase. As of May 2012, these estimates had been used in more than 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[111] In May 2013 and again in November 2013, the Working Group released technical updates that revised its estimate of the Social Cost of Carbon.[112]

[109] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[110] The Working Group's 2010 social cost of carbon values are commonly reported in 2007 dollars of $5, $21, $35, and $65 per metric tonne CO_2. In Exhibit 4-4, these values are converted to 2015 dollars and short tons.

[111] Robert E. Kopp and Bryan K. Mignone (2012). The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15

[112] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2013). Technical Support Document:- Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis- Under Executive Order 12866. URL http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf; http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf. The values presented here have been converted from the published values in 2007$/metric ton to 2015$ per short ton.

Exhibit 4-4. U.S. Interagency Working Group Social Cost of Carbon (2015 dollars per short ton CO_2)

Statistic	Average	Average	Average	95th Percentile
Discount Rate	**5%**	**3%**	**2.5%**	**3%**
2015	$11	$38	$59	$112
2020	$12	$44	$66	$132
2025	$14	$48	$71	$147
2030	$16	$54	$77	$164
2035	$20	$58	$82	$180
2040	$22	$63	$89	$197
2045	$25	$68	$95	$212
2050	$27	$73	$100	$227

Source: US EPA, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866 - Interagency Working Group on the Social Cost of Carbon, United States Government, November 2013 (original values in 2007$ per metric ton). http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf

These social cost of carbon values are the result of the Working Group's reanalysis using the DICE, PAGE, and FUND integrated assessment models, which simplify the relationships among complex climate and economic systems with the goal of providing information useful in making climate policy decisions.[113] The social cost of carbon values are calculated as the net present value of the discounted path of hundreds of years of future damages computed by each of the three models resulting from the addition of a ton of CO_2 emissions in a given year.

The Working Group based its common sets of assumptions regarding emissions, population, and gross domestic product (GDP), used for all three models, on four business-as-usual scenarios from an Energy Modeling Forum (EMF) model comparison exercise and an average of 550 ppm CO_2e scenarios from the same four EMF models.[114] The process-based integrated assessment models used in the EMF survey contain substantially more detailed representations of the climate and energy systems than the DICE, PAGE, and FUND models, but only provide results out to 2100. The Working Group analysis extrapolates these trends out to 2300 based upon assumptions regarding changes in fertility rates, GDP per capita, and carbon intensities.

DICE, PAGE, and FUND all employ simplified climate modules to convert emissions into atmospheric concentrations, and then use a climate sensitivity parameter to convert concentrations into temperature increases. To address the substantial uncertainty in this climate sensitivity parameter, the Working Group conducted a Monte Carlo analysis that averages results from a distribution of likely

[113] The DICE model was further simplified by the Working Group for use in its analysis, see Interagency Working Group 2010.

[114] Clarke, L. (2009). Overview of EMF 22 international scenarios. Available at: https://emf.stanford.edu/projects/emf-22-climate-change-control-scenarios

sensitivities. Three of the four social cost of carbon values are based on the average of this distribution, with the fourth based on the high-cost tail-end 95th percentile.

The DICE, PAGE, and FUND integrated assessment models rely on implied valuations of future climate damages to calibrate their "damage functions," which translate temperature changes into changes in GDP. Climate damage valuation is hampered by significant uncertainty in the climate system itself, long time intervals separating cause and effect, and practical difficulties in assigning monetary values to projected damages that fall outside of the range of past experience. A common practice used in these and other climate-economics models is to set a point estimate for the expected cost of near-term, low-level climate damages and then to extrapolate the costs as rising with the square of temperature change.[115] The climate damage values used in the Working Group analysis represent the most likely level of damage given these estimation techniques, ignoring any uncertainty in the range of damages expected to occur from a given rise in temperature. The EPA notes,

> However, given current modeling and data limitations, [Social Cost of Carbon] does not include all important damages. As noted by the IPCC Fourth Assessment Report, it is "very likely that [SCC] underestimates" the damages. The models used to develop SCC estimates, known as integrated assessment models, do not currently include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models naturally lags behind the most recent research.

AESC 2013 discussed various flaws of the overall methodology and application of the Working Group's Social Cost of Carbon estimates, and presented alternate estimates of the Working Group's Social Cost of Carbon estimates by various researchers, produced by varying several of the analyses' assumptions. The alternate estimates were up to more than an order of magnitude larger than the Working Group's. While beyond the scope of AESC 2015, it is worth mentioning that ongoing research and analysis continues to quantify the degree to which the Working Group's estimates are significantly too low because they fail to account for what are potentially first order effects, effects supported by mounting empirical evidence.[116]

As noted previously, in May and then again in November 2013, the Working Group released a technical update to its Social Cost of Carbon that used the same methodology as 2010, but used updated versions of the DICE, FUND, and PAGE models. The revised modeling exercise resulted in change in the working Group's average, 3-percent-discount-rate social cost of carbon—for 2015, \$25 to \$38 per short ton in 2015 dollars.

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115 Stanton, Ackerman and Kartha (2009) "Inside the Integrated Assessment Models: Four Issues in Climate Economics." Climate and Development 1:2(166-184). DOI 10.3763/cdev.2009.0015

116 For example, see Moore, F. and Diaz, D., "Temperature impacts on economic growth warrant stringent mitigation policy," *Nature Climate Change* 5, 127–131 (2015). The analysis addresses the impact of climate change on GDP growth, which the Working Group's models consider to be exogenous.

For the purposes of AESC 2015, the Working Group's revised $38/t may be viewed as an extreme lower bound to possible non-embedded CO_2 values in 2015.

Control Cost Approach

The Marginal Cost of Stabilizing CO_2 Emissions

Control cost methods generally look at the marginal cost of abating CO_2 emissions—that is, the last (or most expensive) unit of emissions reduction required to comply with regulations. The cost of control approach is often based on regulators' revealed preferences. For example, if air quality regulators require a particular technology that costs $X for each ton of emissions that it achieves, then this can be taken as an indication that regulators value emission reductions at or above $X/t. For CO_2 emissions, however, regulators' preferences are not as yet fully revealed.

A marginal cost of abatement can also be based on a sustainability target of staying at or below the highest level of damage or risk that is considered to be acceptable. In this case, the marginal cost of abatement is the cost per ton of the most expensive technology needed to achieve the sustainability target. A sustainability target for CO_2 emissions relies on the assumption—well established in documents related to international climate policy negotiations—that there is a threshold beyond which the nations of the world deem climatic changes and their associated damages to be unacceptable.

A wealth of well documented, compelling research exists both on setting an acceptable threshold for CO_2 emissions and on current and projected costs of CO_2 emissions abatement technologies. Here, we review several recent analyses of strategies and technologies that would contribute to emission reductions consistent with an increase in average temperature of no more than 2°C above preindustrial levels or atmospheric concentrations no greater than 450 ppm CO_2 equivalent.

The 350 ppm target has been identified and is viewed as a more current target to maintain the global temperature increase above pre-industrial levels at no more than 2°C. According to one source, "The measured energy imbalance [of +0.5 W/m^2] indicates that an initial CO_2 target '<350 ppm' would be appropriate, if the aim is to stabilize climate without further global warming."[117] While there is a lack of abatement cost estimates associated with a 350 ppm target, given the factors described in the following text it is reasonable to conclude that such an abatement cost would be equal or more than the abatement cost associated with a 450 ppm target, and could potentially be considerably higher.[118] The information and analysis presented here focuses on the 450 ppm target, entirely because the available

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[117] Hansen J, et al. (2013) "Assessing 'Dangerous Climate Change': Required Reduction of Carbon Emissions to Protect Young People, Future Generations and Nature. *See also* Hansen J, et al. (2008) "Target Atmospheric CO2: Where Should Humanity Aim?" The Open Atmospheric Science Journal, 2: 217-231.

[118] If the more ambitious target could be achieved using more of the same abatement resource, the marginal cost would be the same. If a different (and therefore more expensive) resource were needed to achieve the target, the cost would be higher.

studies used the 450 ppm level in their analyses. The associated cost estimate can therefore be considered to be a conservative choice.

McKinsey & Company examined abatement technologies in a 2010 report entitled *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. The CO_2 mitigation options identified by McKinsey and the costs of those options are reproduced in Exhibit 4-3. The figure represents a marginal abatement cost curve, where the per-ton cost of abatement is shown on the vertical axis and cumulative metric tons of CO_2 equivalent reductions are shown on the horizontal axis. Global CO_2 mitigation technologies are ordered from least to most expensive with the width of each bar representing each technology's expected total emission reduction. If technologies are assumed to be implemented in order of their costs, beginning with the cheapest abatement options, the marginal cost of maintaining the sustainability threshold is the cost per ton of the most expensive technology needed to provide the appropriate reduction (here, 38 metric gigatons CO_2 equivalent in 2030).

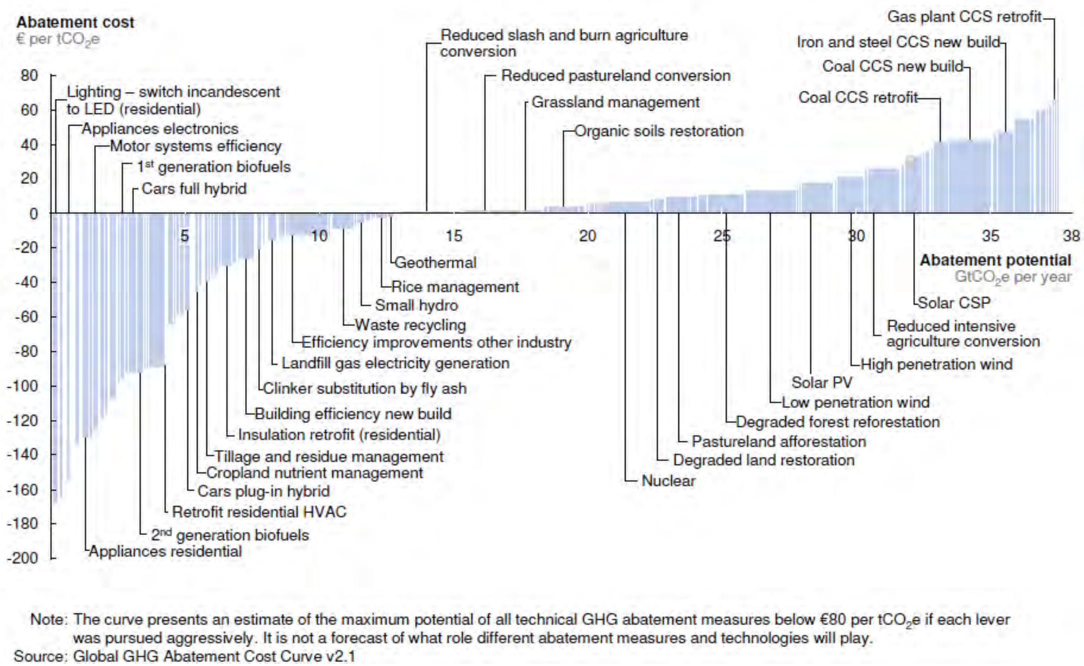
As shown in Exhibit 4-3, the marginal technology for the year 2030 is a gas plant carbon capture and storage (CCS) retrofit costing $120 per short ton in 2015 dollars.[119] This figure also shows a variety of technologies for carbon mitigation that are available to the electric sector, including those related to energy efficiency, nuclear power, renewable energy, and CCS for fossil-fired generating resources.

In *Energy Technology Perspectives 2014* (ETP 2014), the IEA has modeled the implications of several emissions scenarios, and presents marginal CO_2 abatement costs for each. Its 2DS Scenario, an emissions trajectory with at least a 50% chance of limiting average global temperature increase to 2°C, is broadly consistent with IEA's World Energy Outlook (WEO) 450 Scenario, which stabilizes CO_2 levels at 450 ppm.[120] IEA projects global marginal cost of abatements under this and other scenarios for 2020, 2030, 2040, and 2050, with the cost for each year generally spanning a $20 range. The averages of the cost ranges for the 2DS Scenario increase over time from $42 to $163 in 2015 dollars.

[119] 2005 Euro to Dollar conversion factor, 1.25, http://www.oanda.com/convert/fxhistory accessed 4/28/09

[120] IEA (2014). *Energy Technology Perspectives 2014* ("ETP 2014"). Available at: http://www.iea.org/w/bookshop/472-Energy_Technology_Perspectives_2014

Exhibit 4-5. Marginal Abatement Technologies and Associated Costs for the Year 2030



Source: McKinsey & Company. Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve. 2010. Page 8.

In *ETP 2014*, the IEA examines two additional scenarios. Its 4DS scenario, broadly consistent with the WEO New Policies Scenario, projects a long-term temperature rise of 4°C. The WEO New Policies Scenario stabilizes CO_2 levels at 660 ppm.[121] The 6DS scenario, which projects a long-term temperature rise of 6°C, is largely an extension of current trends, and is broadly consistent with the WEO Current Policy Scenario, which stabilizes CO_2 levels at 950 ppm.[122] The 2050 costs for the 4DS and 6DS Scenarios are $53/t and $63/t respectively, in 2015 dollars per short ton.

The global marginal costs of abatement for all of these scenarios are roughly the same as those presented for equivalent scenarios in *WEO 2012* and *ETP 2012*, cited in AESC 2013, whereas those costs represented a decrease on the order of $20/t from the earlier *Energy Technology Perspectives 2010*, primarily as a result of higher projected prices for fossil fuels and more optimistic forecasts for low-carbon technologies.

The results of these studies are summarized in Exhibit 4-4. The dotted line is drawn at the value of atmospheric stabilization of 450 ppm CO_2 equivalent, which corresponds to a good chance of limiting

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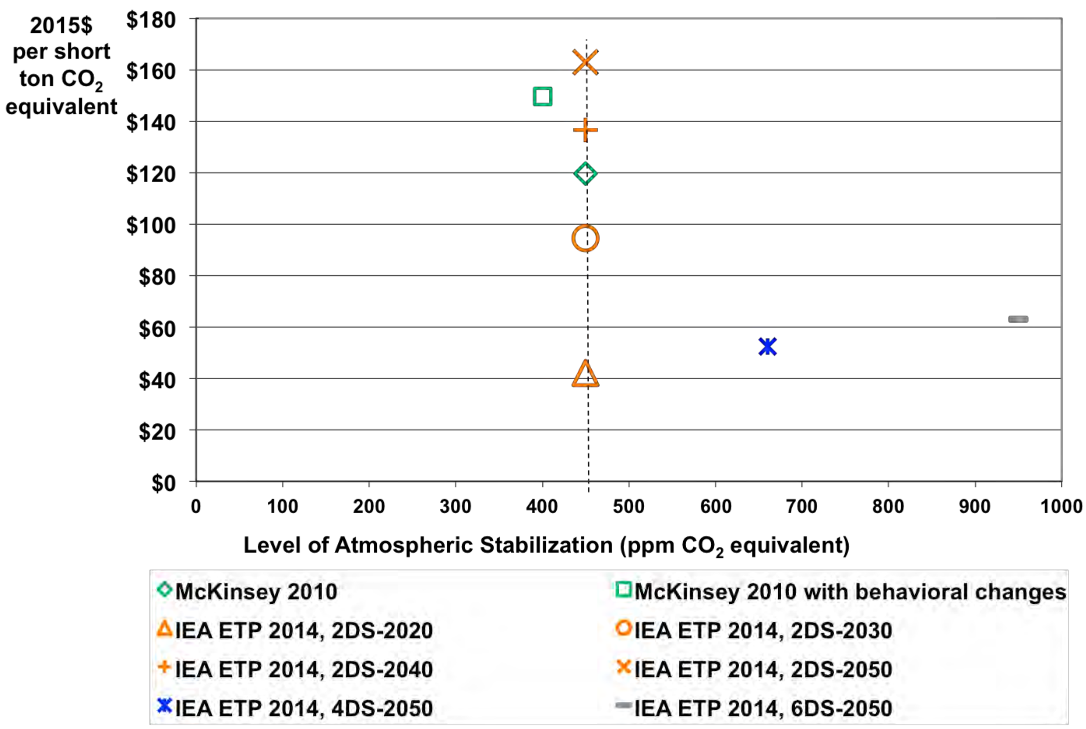
[121] IEA (2012). *World Energy Outlook 2012*. Available at: http://www.worldenergyoutlook.org/publications/weo-2012/

[122] *Ibid.*

global temperature increase to 2°C above pre-industrial levels. Based on this analysis—as well as the CCS costs presented in the section below, and our own judgment and experience—we recommend an AESC 2015 abatement cost of $100 per short ton (in 2015 dollars). This value is unchanged in nominal terms from that of AESC 2013.

Exhibit 4-6. Summary Chart of Marginal Abatement Cost Studies



Source: See text.

CCS Technology Costs

CCS for electricity generation is often at or near the margin for targets of limiting temperature rise to 2°C above pre-industrial levels. For this reason, we expect that CCS costs may be viewed as providing an alternate, first-order approximation of the marginal cost of abating CO_2 emissions. Due to the relatively nascent state of the technology and few projects that are either operating or at advanced stages of development,[123] projected technology costs vary widely, with gas CCS typically more expensive than

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[123] As of November 2014, only two of the 40 large-scale CCS projects in the "operate," "execute" or "define" stages as defined by the Global CCS Institute (GCCSI) were on gas-fired generation: the Peterhead CCS Project in Scotland (340 MW, 1 $MtCO_2$ per year integrated CCS), and Sargas Texas Point Comfort Project (250 MW, 0.8 MtCO2 /year), both in the "define" stage. *See* GCCSI (2014), Status of CCS Project Database. Available at: http://www.globalccsinstitute.com/content/ccs-around-world

coal on a per ton of avoided emissions basis. As presented in AESC 2013, mature CCS deployment estimates are commonly in the range of $60 to $100 per short ton of CO_2 avoided. According to IEA, carbon prices need to approach $84 per short ton (2015 dollars) to drive adoption of CCS—prices above which a CCGT with CCS will have a lower LCOE than either a CCGT or supercritical pulverized coal plant.[124]

Substantial uncertainty still exists in the long-term costs of CCS deployment. CCS costs can provide an important cross-check of long-term forecasts of mitigation costs, but should be coupled with other metrics such as complete marginal cost of abatement curves constructed from energy system modeling results.

CO_2 Abatement Cost in AESC 2015

Based on our review of the most current research on marginal abatement and CCS costs, and our experience and judgment on the topic, we believe that it is reasonable to use a CO_2 marginal abatement cost of $100 per short ton in 2015 dollars. This value is the same in nominal terms as the AESC 2013 value. Because the AESC 2015 embedded CO_2 cost is lower than that of AESC 2013, the non-embedded component is correspondingly higher.

A value of $100/short ton is a practical and reasonable measure of the total societal cost of carbon dioxide emissions. This CO_2 marginal abatement cost can be applied to the emissions reductions that result from lower electricity generation as a result of energy efficiency, in order to quantify these reductions' full value to society. A portion of this CO_2 marginal abatement cost will be reflected in the allowance price for emissions, and thus embedded in the avoided costs; the balance may be referred to as a non-embedded cost.

States that have established targets for climate mitigation comparable to the targets discussed in section 4.3.1, or that are contemplating such action, could view the $100/t CO_2 marginal abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of the cost of reductions in carbon emissions required to achieve those targets.

Like any long-run projections, this estimate of the marginal abatement cost includes important uncertainties in underlying assumptions regarding the extent of technological innovation, the selected emission reduction targets, the technical potential of key technologies, and the evolution of international and national policy initiatives, along with a variety of other influencing factors. It will be necessary to review available information and reassess what value is reasonable given the best state of knowledge at the time of future reviews.

[124] ETP 2014, converted from $80/metric ton in 2012 dollars. This calculation assumes gas prices of $4/MMBtu.

Estimating Non-Embedded CO_2 Costs for New England

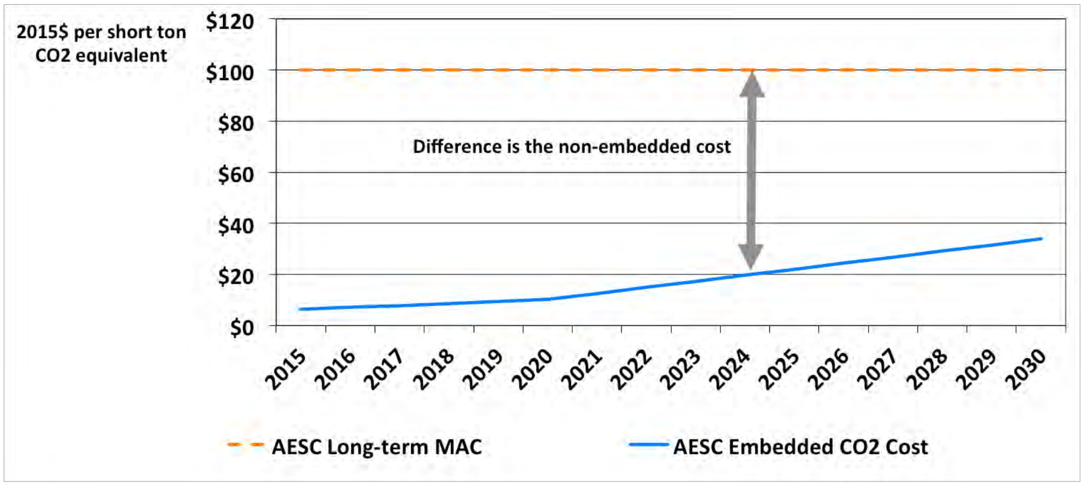
The non-embedded value for New England's CO_2 emissions in each year was calculated as the estimated marginal abatement cost of $100 per short ton in 2015 dollars less the annual allowance values embedded in the projected electric energy market prices. These values are summarized in Exhibit 4-5.

Exhibit 4-7. AESC 2015 Non-Embedded CO_2 Costs (2015 dollars per short ton CO_2)

	Marginal Abatement Cost a	Allowance Price b	Externality c = a - b
2015	$100	$6.28	$93.72
2016	$100	$7.26	$92.74
2017	$100	$7.87	$92.13
2018	$100	$8.47	$91.53
2019	$100	$9.32	$90.68
2020	$100	$10.16	$89.84
2021	$100	$12.54	$87.46
2022	$100	$14.92	$85.08
2023	$100	$17.30	$82.70
2024	$100	$19.67	$80.33
2025	$100	$22.05	$77.95
2026	$100	$24.43	$75.57
2027	$100	$26.80	$73.20
2028	$100	$29.18	$70.82
2029	$100	$31.56	$68.44
2030	$100	$33.94	$66.06

The annual allowance values embedded in the projected electric energy market prices are shown in column b. These carbon prices were included in the generators' bids in the dispatch model runs and therefore are embedded in the AESC 2015 avoided electricity costs. The non-embedded value in each year is the difference between the marginal abatement cost ($100/t) and the value of the embedded carbon price shown in column c. Exhibit 4-6 illustrates the relationship between the embedded and non-embedded CO_2 cost.

Exhibit 4-8. Non-Embedded Cost of CO_2 Emissions (2015$/short ton of CO_2 equivalent)



Comparison to AESC 2013

The AESC 2015 value for the CO_2 marginal abatement cost of $100/ton is the same in nominal terms as the AESC 2013 value. Because the AESC 2015 embedded CO_2 cost is lower than that of AESC 2013, the non-embedded cost is correspondingly higher.

Applying Non-Embedded CO_2 Costs in Evaluating Energy Efficiency Programs

The non-embedded values from Exhibit 4-5 are incorporated as a separate value in the avoided electricity cost workbooks and expressed as dollars per kWh based upon our analysis of the CO_2 emissions of the marginal generating units summarized below. We recommend that program administrators include these values in their analyses of energy efficiency programs unless specifically prohibited from doing so by state or local regulations. At a minimum, program administrators should calculate the costs and benefits of energy efficiency programs with and without these values in order to assess their incremental impact on the cost-effectiveness of programs.

4.4 Value of Mitigating Significant Pollutants

4.4.1 Electricity Generation

Pollutants and Their Significance

Impacts associated with electricity production and uses include a wide variety of air pollutants, water pollutants, and land use impacts. These include the following:

- Air emissions (including SO_2, NO_x and ozone, particulates, mercury, lead, other toxins, and greenhouse gases) and the associated health and ecological damages

- Fuel cycle impacts associated with "front end" activities such as mining and transportation, and waste disposal
- Water use and pollution
- Land use
- Aesthetic impacts of power plants and related facilities
- Radiological exposures related to nuclear power plant fuel supply and operation (routine and accident scenarios)
- Other non-embedded impacts, such as economic impacts (generally focused on employment), energy security, and others

Over time, regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of these costs in their production and use decisions, thereby embedding a portion of these costs in electricity prices. We anticipate that the non-embedded carbon cost will continue to be the dominant non-embedded environmental cost associated with marginal electricity generation in New England.

For AESC 2015, our approach to quantifying the reduction in physical emissions due to energy efficiency is as follows:

- Identify the marginal unit in each hour in each transmission area from our energy model;
- Draw the heat rates, fuel sources, and emission rates for NO_x and CO_2, of those marginal units from the database of input assumptions used in our pCA simulation; and
- Calculate the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of lbs/MWh. We do this by multiplying the quantity of fuel burned by each marginal unit by the corresponding emission rate for each pollutant for that type of unit and fuel.

The calculations for each pollutant in each hour are as follows:

$$\text{Marginal Emissions} = [\text{Fuel Burned}_{MU}\ (\text{MMBtu}) \times \text{Emission Rate}_{MU}\ (\text{lbs/MMBtu}) \times 1\ \text{ton}/2000\ \text{lbs}]/\text{Generation}_{MU}\ (\text{MWh})$$

Where:

Fuel Burned$_{MU}$	=	the fuel burned by the marginal unit in the hour in which that unit is on the margin,
Emission Rate$_{MU}$	=	the emission rate for the marginal unit, and
Generation$_{MU}$	=	generation by the marginal unit in the hour in which that unit is on the margin.

Value of Mitigating Significant Pollutants

The scope of work for AESC 2015 asks for the heat rates, fuel sources, and emissions of NO_x, and CO_2 of the marginal units during each of the energy and capacity costing periods in the 2015 base year. It also asks for the quantity of environmental benefits that would correspond to energy efficiency and demand reductions, in pounds per MWh, respectively, during each costing period.

Exhibit 4-9 summarizes the marginal heat rate and marginal fuel characteristics from the model results. The results are based on the marginal unit in each hour in each transmission area, as reported by the model. Once the marginal units are identified, we extracted the heat rates, fuel sources, and emission rates for the key pollutants from the database of input assumptions used in our pCA simulation of the New England wholesale electricity market.

Exhibit 4-9. 2015 New England Marginal Heat Rate by Pricing Period

	Summer		**Winter**		**Grand Total**
	Off Peak	On Peak	Off Peak	On Peak	
Marginal Heat Rate (BTU/kWh)	8,261	9,551	8,236	8,866	8,495

Exhibit 4-10. 2015 New England Marginal Fuel by Percentage

Marginal Fuel Type	**Summer**		**Winter**		**Grand Total**
	Off Peak	On Peak	Off Peak	On Peak	
Natural gas	85%	85%	85%	83%	85%
Oil	1%	3%	11%	16%	9%
Coal	9%	12%	4%	1%	5%
Nuclear	0%	0%	0%	0%	0%
Other	4%	0%	1%	0%	1%
Renewable	0%	0%	0%	0%	0%
Grand Total	100%	100%	100%	100%	100%

The avoided emissions values shown in the exhibits below represent the averages for each pollutant over each costing period for all of New England in pounds per MWh. The emission rates are presented by modeling zone; however, differences between zones tend to be relatively minor.

Exhibit 4-11. 2015 New England Avoided CO_2 and NO_x Emissions by Pricing Period

Marginal Emission Type	**Summer**		**Winter**		**Grand Total**
	Off Peak	On Peak	Off Peak	On Peak	
CO_2 Rate (lbs/MWh)	1,040	1,086	1,007	1,019	1,029
NO_x Rate (lbs/MWh)	0.446	0.412	0.405	0.480	0.437

Our recommended dollar values to use for relevant “embedded” avoided pollutant emissions are summarized in Exhibit 4-1. Our recommended dollar value to use for non-embedded carbon costs is provided in Exhibit 4-7.

4.4.2 End-Use Natural Gas

We estimate the environmental benefit from reduced combustion of end-use natural gas due to energy efficiency programs with the following analyses:

- Identifying the various pollutants created by the combustion, and assessing which of them are significant and how, if at all, the impact of those pollutants is currently embedded in the cost of natural gas.
- Finding the value associated with mitigation of each significant pollutant and the portion that should be treated as a non-embedded cost.

Natural gas consists of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inert gases (typically nitrogen, carbon dioxide, and helium) (EPA 1999).

In general, the combustion in boilers and furnaces generate the following pollutants (EPA 1999, 1.4-2–5):

- Oxides of nitrogen (NO_x)
- Sulfur oxides (SO_x) (trace levels),[125]
- CO_2 and other greenhouse gases
- Particulates (trace levels)
- Volatile organic compounds
- Carbon monoxide

Pollutants and their Significance

To estimate the absolute quantities of each pollutant from the combustion of natural gas relative to the absolute quantity of each from all sources, we began by estimating the quantity of each that is emitted per MMBtu of fuel consumed. Exhibit 4-12 provides emissions factors for NO_x and CO_2 for three generalized boiler type categories.

[125] Sulfur is generally added as an odorant to natural gas, which generates trace quantities of sulfur oxides when combusted.

Exhibit 4-12. Emission Rates of Significant Pollutants

Boiler Type	NO_x (lbs/MMBtu)	CO_2 (lbs/MMBtu)
Residential boiler	0.092	118
Commercial boiler	0.098	118
Industrial boilers	0.137	118

Notes:

NO_x emissions from industrial boilers without low NO_x burners would be 0.274 lb/MMBtu. We assumed these boilers were controlled in order to be conservative.

NO_x and CO_2 emissions factors for all boilers utilized conversion rate of 1,020 Btu/scf.

Source:

Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. http://www.epa.gov/ttnchie1/ap42/

We apply the pollutant emission rates for these sectors to the quantity of natural gas consumed by each in New England in 2013. The resulting estimated annual quantities of NO_x and CO_2, along with those for electric generation, are presented in Exhibit 4-13.

Exhibit 4-13. 2013 Pollutant Emissions in New England from Natural Gas

Sector	NO_x (tons)	CO_2 (tons)
Residential	9,766	12,466,973
Commercial	8,150	9,780,545
Industrial	8,675	7,435,983
R, C & I Total [a]	**26,592**	**29,683,501**
Electric Generation [b]	3,582	22,521,319

Sources:

[a] Based on gas volumes from Energy Information Administration, http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm

[b] Electric generation emissions from Environmental Protection Agency AMPD Database, http://ampd.epa.gov/ampd/?bookmark=5342

Exhibit 4-13 illustrates that combustion of natural gas is a source of both NO_x and CO_2 emissions. Moreover, these emissions are not currently subject to regulation, as explained below.

- **CO_2:** RGGI applies to electric generating units larger than 25 MW. New England CO_2 emissions for 2013 were 22.5 million tons. The total CO_2 emissions from the end-use sectors above would represent about 57 percent of the total CO_2 emissions, if such emissions were included.
- **NO_x:** The Clean Air Interstate Rule applied only to Massachusetts and Connecticut during the ozone season, as its successor is likely to. New England NO_x emissions for 2013 were

approximately 3,600 tons for just the electric generating sector.[126] The total NO_x emissions from the end-use sectors above would represent about 88 percent of the total NO_x budget if such emissions were included.

Value of Mitigating Significant Pollutants

We estimate the value associated with mitigation of NO_x and CO_2 as the product of the emissions allowance prices presented in Exhibit 4-1 and emission rates in Exhibit 4-12.[127] In addition, for states with aggressive carbon mitigation targets, we provide a value of reducing CO_2 based upon the $100/ton long-term marginal abatement cost of carbon dioxide reduction. The values by end-use sector are summarized below in Exhibit 4-14.

As noted previously, natural-gas combustion is not a significant source of SO_2 emissions. Consequently, we have not included an emission value for SO_2.

[126] A few large sources in the industrial sector are included in CAIR. These include municipal waste combustors, steel and cement plants, and large industrial boilers (such as those located at Pfizer in New London, CT and General Electric in Lynn, MA). However, the number of NO_x allowances used, sold, and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold and traded for electric generating units.

[127] The full non-embedded value associated with NO_x emissions is probably not captured in the allowance price from electricity generation; however, determining that non-embedded value is beyond the scope of this project.

Exhibit 4-14. Annual Pollutant Emission Values by Sector (2015$/MMBtu)

	Residential			Commercial			Industrial		
	NO_x	CO_2	CO_2 at $100/ton	NO_x	CO_2	CO_2 at $100/ton	NO_x	CO_2	CO_2 at $100/ton
2015	$0.000	$0.37	$5.88	$0.000	$0.37	$5.88	$0.001	$0.37	$5.88
2016	$0.000	$0.43	$5.88	$0.000	$0.43	$5.88	$0.001	$0.43	$5.88
2017	$0.000	$0.48	$5.88	$0.001	$0.48	$5.88	$0.001	$0.48	$5.88
2018	$0.000	$0.53	$5.88	$0.001	$0.53	$5.88	$0.001	$0.53	$5.88
2019	$0.000	$0.59	$5.88	$0.001	$0.59	$5.88	$0.001	$0.59	$5.88
2020	$0.001	$0.66	$5.88	$0.001	$0.66	$5.88	$0.001	$0.66	$5.88
2021	$0.001	$0.83	$5.88	$0.001	$0.83	$5.88	$0.001	$0.83	$5.88
2022	$0.001	$1.00	$5.88	$0.001	$1.00	$5.88	$0.001	$1.00	$5.88
2023	$0.001	$1.19	$5.88	$0.001	$1.19	$5.88	$0.001	$1.19	$5.88
2024	$0.001	$1.38	$5.88	$0.001	$1.38	$5.88	$0.001	$1.38	$5.88
2025	$0.001	$1.57	$5.88	$0.001	$1.57	$5.88	$0.001	$1.57	$5.88
2026	$0.001	$1.78	$5.88	$0.001	$1.78	$5.88	$0.001	$1.78	$5.88
2027	$0.001	$1.98	$5.88	$0.001	$1.98	$5.88	$0.001	$1.98	$5.88
2028	$0.001	$2.20	$5.88	$0.001	$2.20	$5.88	$0.001	$2.20	$5.88
2029	$0.001	$2.43	$5.88	$0.001	$2.43	$5.88	$0.001	$2.43	$5.88
2030	$0.001	$2.66	$5.88	$0.001	$2.66	$5.88	$0.001	$2.66	$5.88
Levelized (2015$/MMBtu)									
5 year (2016-20)	$0.000	$0.54	$5.88	$0.001	$0.54	$5.88	$0.001	$0.54	$5.88
10 year (2016-25)	$0.001	$0.84	$5.88	$0.001	$084	$5.88	$0.001	$084	$5.88
15 year (2016-30)	$0.001	$1.24	$5.88	$0.001	$1.24	$5.88	$0.001	$1.24	$5.88

Notes:

Based on Emission Rates of Significant Pollutants for Natural Gas in Exhibit 4-12.

Pollutant values based on emission allowance prices detailed in Exhibit 4-1 and $100/short ton long-term marginal abatement cost for CO_2.

The entire amount of each value is a non-embedded cost. With the exception of those industrial sources subject to the EPA NO_x budget programs, which represent a small fraction of the total emissions, none of these emissions are currently subject to environmental requirements. Therefore, none of these values are embedded in their market prices.

4.4.3 End-Use Fuel Oil and Other Fuels

We estimate the environmental benefit from reduced combustion of fuel oil and other fuels due to energy efficiency programs with the following analyses:

- Identifying the various pollutants created by the combustion, and assessing which of them are significant and how, if at all, the impact of those pollutants is currently embedded in the cost of the studied fuels.
- Finding the value associated with mitigation of each significant pollutant and the portion that should be treated as a non-embedded cost.

The pollutant emissions associated with the combustion of fuel oil are dependent on the fuel grade and composition, boiler characteristics and size, combustion process and sequence, and equipment maintenance (EPA 1999 1.3-2). [128]

In general, the combustion in boilers and furnaces generate the following pollutants (EPA 1999, 1.4-2–5):

- Oxides of nitrogen (NO_x)
- Sulfur oxides (SO_x)
- CO_2 and other greenhouse gases
- Particulates
- Volatile organic compounds
- Carbon monoxide
- Trace elements
- Organic compounds

Pollutants and Their Significance

Like the combustion of natural gas, NO_x, SO_x, and CO_2 are potentially the most significant pollutants.[129] NO_x is a precursor to the unhealthy concentrations of ozone that areas in New England continue to experience. The region is also required to reduce NO_x and SO_x emissions by EPA programs, implement state low sulfur fuel requirements, and participate in the RGGI program to reduce CO_2 from the power sector, as described in Section 4.2.2.

For the electric generation sector, the forecast of emissions allowance prices value of mitigating emissions of from the combustion of NO_x, SO_x, and CO_2 is shown in Exhibit 4-1.

In order to estimate the absolute quantities of each pollutant from the combustion of fuels by sector, we began by estimating the quantity of each pollutant that is emitted per MMBtu of fuel consumed.[130] The pollutant emissions associated with the combustion of wood are dependent on the species of wood, moisture content, appliance used for its combustion, combustion process, and sequence and equipment

[128] EPA, 1999. "Stationary Point and Area Sources" v. 1 of Compilation of Air Pollutant Emission Factors 5th Ed. AP-42. Triangle Park, N.C.: U.S. Environmental Protection Agency. (Section 1.3-2)

[129] Wood combustion may contribute to an accumulation of unhealthy concentrations of fine particulate matter ($PM_{2.5}$). This is especially true in many valleys, where pollutants accumulate during stagnant meteorological conditions. The regulation of $PM_{2.5}$ from wood combustion is a state by state process. No comparable regionally consistent or market-based program of allowances have been established for $PM_{2.5}$, like those described above for SO_x, NO_x, and CO_2.

[130] Number-6 fuel oil has about the same rate of SO_2 emissions as distillate, about twice the rate of NO_x emissions and about seven percent higher rate of CO_2 emissions.

maintenance. The pollutant emissions associated with the combustion of kerosene are similar to those associated with the combustion of distillate oil, and depend upon boiler characteristics and size, combustion process and sequence, and equipment maintenance (EPA 1999, 1.3-2).

Exhibit 4-15 provides emissions factors for each fuel based on predominant sector-specific characteristics.

Exhibit 4-15. Emission Rates of Significant Pollutants from Fuel Oil

Sector and Fuel	SO_2 (lbs/MMBtu)	NO_x (lbs/MMBtu)	CO_2 (lbs/MMBtu)
#2 Fuel Oil [a,b]			
Residential, #2 oil	0.002	0.129	163
Commercial, #2 oil	0.002	0.171	163
Industrial, #2 oil	0.002	0.171	163
Kerosene—Residential heating [c]	0.152	0.129	173
Wood—Residential heating [d]	0.020	0.341	N/A

Notes:
For fuel oil, assumed sulfur content of 15 ppm.

Sources:
[a] Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. *http://www.epa.gov/ttnchie1/ap42/* (for SO_2 and NO_x)
[b] Based on "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012," Table A-11: 2012 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type, US EPA, 2013. http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html (for CO_2)
[c] AESC 2013.
[d] James Houck and Brian Eagle, OMNI Environmental Services, Inc., Control Analysis and Document for Residential Wood Combustion in the MANE-VU Region, December 19, 2006. http://www.marama.org/publications_folder/ResWoodCombustion/RWC_FinalReport_121906.pdf

Next, we applied those pollutant emission rates to the quantity of each fuel consumed by sector in New England in 2012 (Exhibit 4-16), with one exception: EIA supply data for 2012 indicated a supply mix of approximately 20% low sulfur distillate and 80% ULSD. For this reason, we assumed a weighted average sulfur content of 112 ppm rather than 15 ppm. The results are shown in Exhibit 4-17.

Exhibit 4-16. New England Distillate Consumption, 2012

	Residential	Commercial	Industrial
Distillate Consumption, 2012 (Trillion BTU)	217	60	24

Note:
Includes entire state of Maine.

Source:
Distillate Fuel Oil Consumption Estimates, US EIA, 2012.
http://www.eia.gov/state/seds/data.cfm?incfile=/state/seds/sep_fuel/html/fuel_use_df.html&sid=US

Exhibit 4-17. Pollutant Emissions in New England for Selected Sources

Sector	SO_2 (tons)	NO_x (tons)	CO_2 (tons)	
Emissions from Electric Generation	35,762	43,017	38,242,782	**A**
R, C & I Natural Gas Combustion		23,029	25,541,693	**B**
R, C & I #2 Fuel Oil Combustion				
Residential	1,061	12,009	15,247,491	i
Commercial	250	3,771	3,586,600	Ii
Industrial	105	1,577	1,500,491	Iii
R, C & I Total	1,415	17,357	20,334,583	**C** = i + ii + iii
Residential Combustion of Kerosene	127	108	144,194	**D**
Residential Combustion of Wood	341	5,862	0	**E**
Total	37,645	89,373	84,263,251	**F** = A+B+C+D+E
Natural gas as percent of total	**0%**	**26%**	**30%**	B/F
Other fuel as percent of total	**5%**	**26%**	**24%**	(C+D+E)/F
Non-electric as percent of total	**5%**	**52%**	**55%**	(B+C+D+E)/F

Notes:

All figures are for 2012. Natural gas values equivalent to those in Exhibit 4-13, but for 2012.
SO_2 emissions for #2 fuel oil based on weighted average fuel sulfur content of 112 ppm for low sulfur heating oil.
Includes entire state of Maine, not just portion within ISO-NE.

Value of Mitigating Significant Pollutants

Emissions of NO_x, SO_x, and CO_2 from the combustion of these fuels are not currently subject to regulation, as explained below.

All of these values are non-embedded values.

- SO_2 and CO_2: The acid rain program and RGGI apply to electric generating units larger than 25 MW. New England SO_x emissions from electric generating units for 2012 were approximately 35,800 tons. The total SO_x emissions from the end-use sectors above would represent approximately 5 percent of the total SO_x emissions, if such emissions were included.[131] New England electric generation CO_2 emissions for 2012 were approximately 38.2 million tons. The calculated CO_2 emissions from the non-electric end-use sectors above would represent approximately 55 percent of the total CO_2

[131] Northeastern states began in 2012 to phase in requirements for ultra-low sulfur distillate (ULSD, 15 ppm sulfur). With the exception of New Hampshire, the transition to new requirements will be complete by mid-2018. In conjunction with this transition, the Northeast Home Heating Oil Reserve converted to ULSD in 2011, and in 2013, NYMEX switched its specification for the heating oil futures contract to the ULSD specification. As a result, approximately 80% of the supply (as indicated by 2012 EIA data) had shifted to the new specification by 2012. Taking the lower sulfur content into account in our analysis of 2012 resulted in a significant decrease in the estimate for fuel oil SO_2 emissions, relative to the AESC 2013 estimate for 2011.

emissions shown here, with natural gas accounting for 30 percent and other fuels accounting for 24 percent.

- NO_x: The Ozone Transport Commission–EPA NO_x budget program applies to electric generating units larger than 15 MW and to industrial boilers with a heat input larger than 100 MMBtu per hour. New England NO_x emissions for 2012 were approximately 43,000 tons for just the electric generating sector.[132] The calculated NO_x emissions from the non-electric end-use sectors above would represent approximately 52 percent of the total NO_x emissions shown here, split evenly between natural gas and other fuels.

The allowance prices associated with electricity generation for NO_x and SO_x represent the value associated with mitigating these emissions on the 2015 NO_x and SO_2 emissions allowance prices per short ton in Exhibit 4-1, the value AESC 2015 has internalized in its forecast consistently across fuels as noted elsewhere in this chapter.[133] Those values, per MMBtu of fuel, are presented in Exhibit 4-18.

Because we have estimated the full cost of CO_2 mitigation, and because none of that cost is embedded in the prices of non-electricity fuel use, the value of CO_2 shown in Exhibit 4-18 is the long-term marginal abatement cost of $100/ton, presented here per MMBtu of fuel.

Exhibit 4-18. Value of Pollutant Emissions from Fuel Oil in 2015 (2015$/MMBtu)

Sector	SO_2	NO_x	CO_2
Residential	$0.0000	$0.0001	$8.16
Commercial	$0.0000	$0.0001	$8.15
Industrial	$0.0000	$0.0001	$8.15

With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of the non-electric emissions shown in Exhibit 4-17 are currently subject to environmental requirements.[134] None of the values shown in Exhibit 4-18, therefore, are internalized in the relevant fuels' market prices.

The values by year for fuel oil over the study period are presented in Appendix E.

[132] A few large sources in the industrial sector are included in the NO_x budget program. These include municipal waste combustors, steel and cement plants and large industrial boilers (such as those located at Pfizer in New London, Connecticut, and General Electric in Lynn, Massachusetts). However, the number of NO_x allowances used, sold and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold, and traded for electric generating units.

[133] The full externality value associated with SO_x and NO_x emissions is probably not captured in the allowance price from electricity generation associated with these two pollutants; however, determining that externality value is beyond the scope of this project.

[134] EPA. Factsheet: EPA's Final Air Toxics Standard Major and Area Source Boilers and Certain Incinerators Overview of Rules and Impacts. Available at http://www.epa.gov/airquality/combustion/docs/overviewfsfinal.pdf. Accessed January 30, 2015.

4.5 Discussion of Non-Embedded NO_x Costs

This section addresses the request in the AESC 2015 scope of work to provide a discussion of non-embedded NO_x costs. We are not recommending an additional non-embedded NO_x value additive to the embedded allowance prices based on the analysis discussed in this section; rather, we recommend an approach consistent with AESC 2013, and detailed below.

4.5.1 Health Impacts and Damages

NO_x emitted from the combustion of coal and natural gas reacts with compounds in the air ("precursors") to produce ozone, particulate matter ("PM2.5"), and acid rain. Both PM2.5 and ozone are EPA criteria pollutants that have been shown to have harmful effects on human health, and are regulated under the Clean Air Act. Quantifying the value associated with damages from NO_x emissions is a particularly complicated process. Most studies look at incidence rates of premature death and chronic respiratory diseases such as bronchitis, emphysema, and asthma in order to evaluate health impacts. The reaction of NO_x with precursors to form PM2.5 and ozone is highly dependent on atmospheric conditions and local emissions of other precursors. Fowlie and Muller use a stochastic model to estimate damages and quantify health impacts for 565 coal plants, with average impacts on human health to be valued at $1,795/ton NOx. The intra-source variation in damage estimates they found was considerable; their damage estimate for a representative source in Ohio was $1,549/ton NO_x, with a standard deviation of $1,859/ton (2015 dollars).[135] Mauzerall et al. found a similar level of uncertainty in an earlier study, citing one location where the health impact of emissions nearly doubled within a short span of time as the temperature changed.[136] EPA has used the BenMAP tool to calculate benefits of NO_x reduction based on reduced mortality from particulate matter, and calculates 2015 national benefits of approximately $20,000/ton for electricity generation and $13,000/ton for non-electricity sources (2015 dollars), with considerable variation in benefit levels among the nine metropolitan areas examined.[137]

The analyses above do not include valuation of the impacts of environmental effects resulting from nitrogen deposition, or visibility impairment from increased haze.

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[135] Fowlie, M. N. Muller (2013) "Market-Based Emissions Regulation When Damages Vary Across Sources: What Are the Gains from Differentiation?" (With appendices). National Bureau of Economic Research. NBER Working Paper No. 18801. $1,734, $1,496, and $1,976 in 2013 dollars, respectively. http://nature.berkeley.edu/~fowlie/papers.html

[136] Mauzerall, D.L., B. Sultan, N. Kim, and D.F. Bradford. 2005. "NO_x emissions from large point sources: Variability in ozone production, resulting health damages and economic costs." Atmos. Environ. 39(16):2851-2866

[137] EPA (2015). "RSM-based Benefit per Ton Estimates." Values in 2006$: $17,000 and $11,000. Accessed January 30, 2015. Available at: http://www.epa.gov/oaqps001/benmap/bpt.html

4.5.2 Abatement Costs

In New England, significant progress on NO_x abatement has already been made, marked by rapid reductions over the past decade (see Exhibit 4-19).

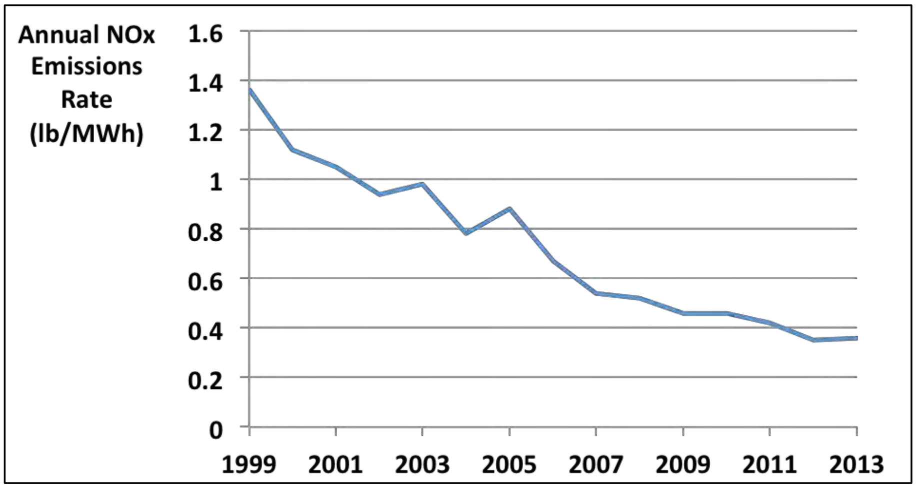
Market prices for NO_x emissions fall far below the estimated costs of health impacts. AESC 2013 embedded NO_x prices were approximately $28 per ton; by the end of 2014, values for costs of NO_x mitigation under CAIR had fallen substantially from those cited in AESC 2013 to levels in the $10/ton range. With the replacement of CAIR by CSAPR, NO_x mitigation costs in New England are currently uncertain.[138]

Connecticut and Massachusetts had been included in the ozone-season CAIR program, but not in CSAPR because air quality modeling shows they no longer contribute significantly to nonattainment of the 1997 ozone or 1997 and 2006 PM NAAQS in other states.[139] Nevertheless, the two states had relied on CAIR reductions to comply with air quality obligations under Regional Haze and ozone NAAQS. Options to maintain the reductions include intrastate NO_x trading programs, and enforceable ozone season emission limits on CAIR units; a number of SIPs in the two states will likely need amending in order to meet remaining obligations. Once more information is available about a potential Federal CAIR replacement for New England, and amended SIPs are in place, the impact on future compliance costs should become more apparent.

[138] With the restarting of CSAPR in January 2015, CSAPR NO_x allowance prices traded in the $250/ton range, although those prices are irrelevant to generators in the New England states, which are not subject to the rule.

[139] US EPA presentation, "CSAPR Stay Lifted – Implications for Connecticut Sources," David B. Conroy, CT SIPRAC, November 13, 2014. Available at: http://www.ct.gov/deep/lib/deep/air/siprac/2014/conroy_ctsiprac11132014.pdf

Exhibit 4-19. Annual NO_x Emissions Rate in New England (lb/MWh)



Source: 2013 ISO New England Electric Generator Air Emissions Report. December 2014. http://www.iso-ne.com/static-assets/documents/2014/12/2013_emissions_report_final.pdf

4.6 Compliance with State-Specific Climate Plans

The AESC 2015 scope of work required the project team to determine if there was some component of compliance with state-specific regulations or climate plans that would directly impact generators and that the project team could quantify and credibly support. The scope of work further required the project team, if it made such a determination, to include their estimate of that compliance cost in one of the three categories of costs related to emissions control reflected in the AESC 2015 avoided energy cost forecast. (Those three categories of emissions control costs are "currently enforced," "enacted, but not yet in effect," and "reasonably expected to be enacted.") This is because, due to the nature of the regional market, the costs of complying with one state's law may also affect avoided costs in other states in the New England market. The scope notes that AESC 2015 was not to determine the value of full compliance with these plans, laws, or regulations or the impact of energy efficiency on other sectors that may also be covered by them, such as transportation or industry, in achieving the overall objectives of the plan, law or regulation.

The project team is not aware of any instances of state-specific climate plans that will *directly* affect generators, other than those already discussed and accounted for in the analysis of embedded environmental costs associated with state compliance with regional or Federal standards and costs associated with renewable portfolio standards.

As described above, there is one proceeding that could impact the estimate of non-embedded costs in Massachusetts, i.e., DPU Docket No. 14-86. In that proceeding the Massachusetts DEP and DOER filed a joint petition requesting the DPU to determine whether the existing method of calculating the costs of reducing GHG emissions to comply with the Global Warming Solutions Act (GWSA) should be replaced by a marginal abatement cost curve approach, and that Program Administrators incorporate estimates of avoided GWSA compliance costs in energy efficiency cost-effectiveness analyses. The petitioners have filed estimates of GWSA compliance costs and have asked the DPU to order that these values be used.[140] The proceeding is still underway as of this writing, and the DPU has not yet made a determination. It should be noted that the marginal abatement cost for Massachusetts to achieve compliance with the GWSA are not comparable with the global marginal abatement costs to achieve specific atmospheric CO_2 concentrations, discussed above.

Additionally as described above, Mass DEP in early January 2015, published a proposed "Clean Energy Standard" regulation for public comment. A Massachusetts CES would implement one of the strategies in the CECP, and providing a long-term incentive to ensure ongoing progress toward reducing greenhouse gas emissions by 80 percent by 2050. The proposed regulation would qualify clean energy generators based on a generic 50 percent-below-natural-gas threshold, and would count RPS compliance toward CES compliance, with CES targets exceeding RPS targets. Resources outside ISO-NE such as Canadian hydro would be required to use transmission that commenced operation after 2010.[141] Public comment on the proposed regulations is being accepted through April 27, 2015.

[140] For the proposed values and a description of the proposed approach, see "Amended Direct Testimony of Elizabeth A. Stanton On Behalf of the Department of Energy Resources and the Department of Environmental Protection Regarding the Cost of Compliance with the Global Warming Solutions Act," September 16, 2014, filed in MA D.P.U. No. 14-86.

[141] "Summary of Proposed MassDEP Regulation: Clean Energy Standard (310 CMR 7.75)," Available at: http://www.mass.gov/eea/docs/dep/air/climate/ces-fs.pdf. Additional information available at http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/ces.html.

Chapter 5: Avoided Electric Energy and Capacity Costs

This chapter provides projections of avoided electric energy and capacity market prices, as well as Renewable Portfolio Standard (RPS) compliance costs that are not embedded in those market prices. We present the projections of electric energy and capacity market prices in the same chapter because these projections are directly interrelated, capacity prices in the long-term affect energy prices in the long-term and vice versa.

The chapter presents projections of avoided electric energy and capacity market prices for two cases, a Base Case and a BAU Case. The Base Case assumes no reductions from new ratepayer funded energy efficiency programs approved from January 2015 onward except for the reductions which have been bid into the Forward Capacity Auctions for power years through May 2018. The BAU Case assumes a continuation of reductions from ratepayer funded energy efficiency at the levels reflected in ISO-NE forecasts.

This chapter is organized as follows:

- Section 5.1S provides an overview of wholesale energy and capacity markets in New England.
- Section 5.2 describes the model AESC 2015 used to simulate the operation of those two markets.
- Section 5.3 describes the common assumptions AESC 2015 used to simulate the operation of those two markets.
- Section 5.4 describes the assumptions AESC 2015 used solely to simulate the operation of the capacity market;
- Section 5.5 presents the Base Case projections and compares those results to AESC 2013. Appendix B provides detailed results for each year of the study period, by zone by season, by period (i.e. on-peak, off-peak);
- Section 5.6 presents the projections of RPS compliance costs. Appendix F provides detailed renewable energy certificate (REC) price forecasts and avoided RPS costs by state for each year of the study period; and
- Section 5.7 presents an assessment of alternative electric energy costing periods.

5.1 New England Wholesale Energy and Capacity Markets

5.1.1 Wholesale Energy Markets

ISO New England (ISO-NE) manages two primary wholesale energy markets, Day-Ahead and Real-Time, with the objective of:

> The primary objective of the electricity markets operated by ISO New England is to ensure a reliable and economic supply of electricity to the high-voltage power grid. The markets include a Day-Ahead Energy Market and a Real-Time Energy Market. In what is termed a multi-settlement system, each of these markets produces a separate but related financial settlement.142

Most transactions are scheduled in the Day-Ahead Market, with transactions in the Real-Time Market limited to balancing actual supplies with actual demands in real time. On average energy prices in the markets are very close, although real-time market prices exhibit greater volatility.

The Day-Ahead Energy Market produces financially binding schedules for the sale and purchase of electricity one day before the operating day. However, supply or demand for the operating day can change for a variety of reasons, including forecast error for load and for variable resources such as wind and solar, generator reoffers of their supply into the market, real-time hourly self-schedules (i.e., generators choosing to be on line and operating at a fixed level of output regardless of the price of electric energy), self-curtailments, transmission or generation outages, and unexpected real-time system conditions.

Physically, real-time operations balance instantaneous changes in supply and demand and ensure that adequate reserves are available to operate the transmission system within its limits. Financially, the Real-Time Energy Market settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Participants in this market either pay, or are paid, the real-time locational marginal price (LMP) (see below) for the amount of load or generation in megawatt-hours (MWh) that deviates from their day-ahead schedule.

Unit Commitment

In a power system the supply curve in a given hour is defined by the set of generating units committed to run in that hour. The process through which the system operator, in New England it is ISO NE, schedules individual generating units to be run in a given hour of a given day, or not run in that hour of that day, is referred to as "unit commitment". [143]

[142] ISO-New England 2010 Annual Market Report (2011, 29–30)

[143] Lelic, Lzudin. Unit Commitment & Dispatch, Introduction to Wholesale Electricity Markets (WEM 101), ISO NE, September 15-19, 2014

Unit commitment is related to, but different from, economic dispatch. The goal of the unit commitment decision is find the least-cost mix of units to supply energy for the 24 hours period for which the decision is being made, plus at least another 24 hours of the look-ahead time to correctly assess the future implications of decisions made for the first 24 hours. Thus, ISO NE is making unit commitment decisions for a 24 hour period, not a 1 hour period. ISO NE makes unit commitment decisions for each unit based on the unit's operational constraints in addition to the load to be served and the economics of the unit. The operational constraints include minimum up- and down-times, minimum operating limits, and start-up costs

ISO New England makes its initial unit commitment decision prior to the power day, and then makes additional decisions during the day. For a given day, ISO New England makes its first (and financially binding) unit commitment decision by 13:30 on a preceding day – Day-ahead market clearing and formation of day-ahead LMPs. After that ISO-NE immediately opens re-offer period and by 17:00 of the preceding day produces an update to the unit commitment decision through the process known as Resource Adequacy Assessment (RAA)/security constrained reliability assessment (SCRA). During the operating day, ISO NE continues to perform SCRA for that day. At each unit commitment decision ISO NE effectively modifies the set of committed generating resources influencing price formation. One of the most critical inputs into the unit commitment process is the level of demand anticipated to be served during the entire optimization horizon of the unit commitment process. In the day ahead market, the demand is determined through demand bids, decrement bids and export external transactions. In the RAA/SCRA, ISO New England augments bid information with current demand forecasts.

ISO NE produces unit commitment decisions by solving advanced algorithms of the mixed integer linear programming problem. In formulating and solving this problem, ISO NE considers not only fuel and variable O&M costs submitted by generation owners though supply offers, but also start-up costs and opportunity costs associated with running energy limited resources such as hydro and pumped storage resources. This problem is essentially a dynamic optimization problem with economic and operational considerations spanning over 24 hours of the day for which the problem is being solved plus at least another 24 hours of the look-ahead time to correctly assess the future implications of decisions made for the first 24 hours. The solution to this problem is sensitive to the level of load that the power system is projected to serve.

Locational Marginal Prices

Wholesale electric energy prices are set at various pricing points or "nodes" throughout New England referred to as "pnodes". These prices, referred to as "locational marginal prices" (LMP), reflect the value of electric energy at those specific locations by accounting for the patterns of load, generation, and the physical limits of the transmission system at those locations. New England wholesale electricity prices are identified at 900 pnodes on the bulk power grid. If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment of load. This incremental megawatt of load would be served by the generator with the lowest-cost energy offer available to serve that load, and electric energy from that generator would be able to flow to any node on the transmission system. LMPs differ among locations during time periods when transmission and reserve constraints prevent the next-cheapest megawatt (MW) of electric energy from reaching all locations of the grid. In addition, even during periods when the cheapest megawatt can reach all locations, the marginal cost of physical losses will result in different LMPs across the system.

New England has five types of pnodes, with "hub" nodes representing load-weighted prices for uncongested areas, or load zones. New England currently has eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). Generators are paid the day-ahead and real-time LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones.

Import-constrained load zones are areas within New England that must use more expensive generators than the rest of the system because local, inexpensive generation or transmission-import capability is insufficient to meet both local demand and reserve requirements. Export-constrained load zones are areas within New England where the available resources, after serving local load, exceed the areas' transmission capability to export excess electric energy.

5.1.2 Wholesale Capacity Markets

ISO New England describes this market as follows:

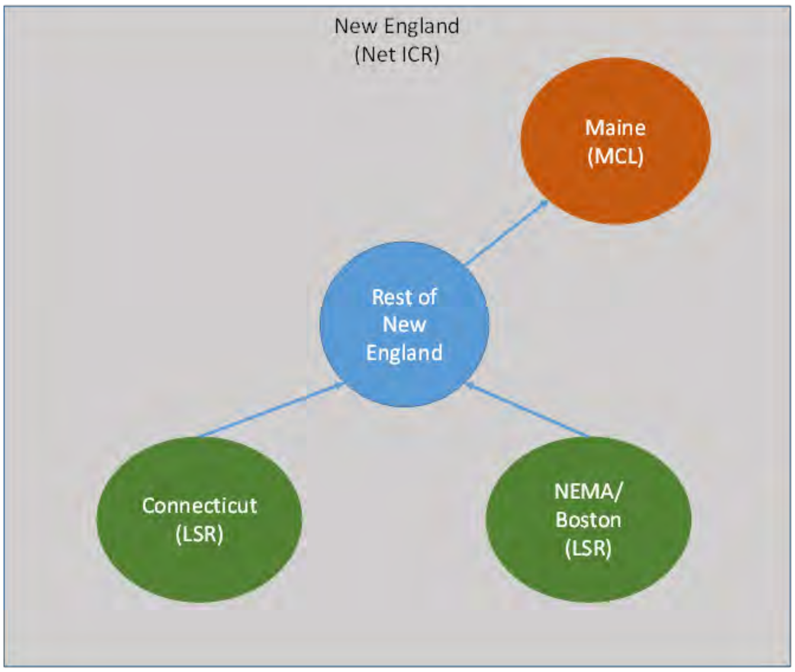
> [t]he Forward Capacity Market is a long-term wholesale market that assures resource adequacy, locally and system wide. The market is designed to promote economic investment in supply and demand resources where they are needed most. Capacity resources may be new or existing resources and include supply from power plants, import capacity, or the decreased use of electricity through demand resources. To purchase enough qualified resources to satisfy the region's future needs and allow enough time to construct new capacity resources, Forward Capacity Auctions (FCAs) are held each year approximately three years in advance of when the capacity resources must provide service. Capacity resources compete in the annual FCA to obtain a commitment to supply capacity in exchange for a market-priced capacity payment.[144]

ISO NE uses FCAs to ensure a sufficient quantity of capacity is available to serve the region in each power year, i.e., June 1 to May 31. This quantity, the "installed capacity requirement' or ICR, is equal to the projected peak for the year plus a reserve margin. The ICR defined for the entire system does not reflect locational capacity requirements due to transmission constraints preventing ISO NE from using every MW of installed capacity to meet demand at any location on the system. Unlike energy market, in which transmission constraints are represented explicitly, in the FCA design transmission limitations are implicit in the determination of locational requirements for installed capacity. To determine these locational requirements, ISO New England uses a sophisticated probabilistic modeling of the electrical

[144] "Introduction to New England's Forward Capacity Market. ISO 101," ISO New England.

grid. This modeling is conducted annually and employs General Electric Multi Area Reliability Simulator (GE MARS). The most recent study published by ISO New England is for the 2017-2018 commitment period.[145] Exhibit 5-1 depicts the schematics of locational installed capacity requirements in New England.

Exhibit 5-1. Schematics of FCA Capacity Requirements[146]



As shown in this figure, installed capacity requirements in New England are set as follows:

- System-wide Installed Capacity Requirement (ICR). For the purpose of the study, AESC 2015 used ICRs that are net of capacity supply provided by imports from Hydro Quebec across HVDC interties (Net ICR represented by the gray rectangle).
- Local Sourcing Requirements (LSRs) for import constraint zones – Connecticut and NEMA/Boston represented by green ovals. Local sourcing requirements specify the minimum level of capacity that must be procured from resources electrically located in import-constrained zones.

145 ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2017/18 Capacity Commitment Period.

146 This schematics does not show SEMA as another import constrained zone. At the time when TCR was preparing this analyses, it had no sufficient information to explicitly model SEMA as a capacity zone.

- Maximum Capacity Limit (MCL) for export constrained zone – Maine represented by the orange oval. MCL is the maximum capacity that can be procured in the export constrained zone.
- The diagram in Exhibit 5-1 also depicts a notional Rest of New England Zone (blue circle) for which no requirements are specified. The arrows between constrained zones and the Rest of New England simply reflect the directions in which excess capacity can be sold. Thus, capacity in an excess constrained zones that is in the excess of LSR in that zone can be sold to meet system-wide ICR. However, as the direction of the arrow indicates, the reverse is not true, capacity not located in the import-constrained zone cannot be sold to meet LSR in that zone. In contrast, for the export constrained zone, capacity located elsewhere can be used to meet MCL in that zone. However, no capacity in Maine in excess of MCL can be sold to meet system-wide requirements.

During the auction, suppliers submit offers to meet installed capacity requirements: MW quantities of generation and/or demand resources and offered prices. In addition, suppliers may submit delist bids indicating that certain capacity will not be available to meet the demand. The auctioneer ultimately selects a set of offers which are sufficient to meet capacity requirements while minimizing the total costs (as offered) of meeting those requirements. The outcome of the auction is the set of resources selected to meet ICAP requirement and capacity prices. Each FCA is held to acquire capacity commitments for that power year.

5.2 Market Simulation using *pCloudAnalytics* (*pCA*)

AESC 2015 developed projections of electric energy and electric capacity prices by simulating the operation of the ISO New England markets for energy and ancillary services (E&AS) and for capacity, i.e., the Forward Capacity Market (FCM) interactively using pCloudAnalytics (pCA).

pCA utilizes the Power System Optimizer Model (“PSO”) developed by Polaris Systems Optimizations, Inc. (“Polaris”)[147] to perform the production cost modeling of the ISO New England power system. PSO is a detailed, MIP based, unit commitment and economic dispatch model that simulates the operation of the electric power system. PSO determines the security-constrained commitment and dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area. PSO support both hourly and sub hourly timescales. The analytical structure of PSO is graphically presented in Exhibit 5-2 which distinguishes four important components of PSO: Inputs, Models, Algorithms and Outputs. This document primarily focuses on data sources and analytical steps used by NEG to develop Inputs to the PSO. Where relevant,

[147] http://www.psopt.com

this assumptions document describes how PSO Models are configured to provide adequate representation of the ISOE New England's energy market.

pCA is a cloud based power market simulation environment implemented on Amazon EC2 commercial cloud and organized as Software as a Service (SaaS). TCR licenses this service from Newton Energy Group, pCA developer and vendor. Exhibit 5-3 provides a graphical representation of *pCA* architecture. *pCA* manages formation of data inputs for PSO organized into distinct simulation scenarios, partitions each scenario into concurrently simulated segments, provides virtual machines on the cloud to process segments through PSO, collects and reassembles simulations results into scenario specific outputs and loads them into the Power Explorer (pEx), multi-dimensional data structure accessible through Microsoft Excel via pivot tables. The user prepares input data and accesses modeling results in MS Excel. The user communicates with cloud resources through pLINC, a special software tool linking user's local environment with the cloud environment in Amazon EC2.

Exhibit 5-2. Analytical Structure of PSO

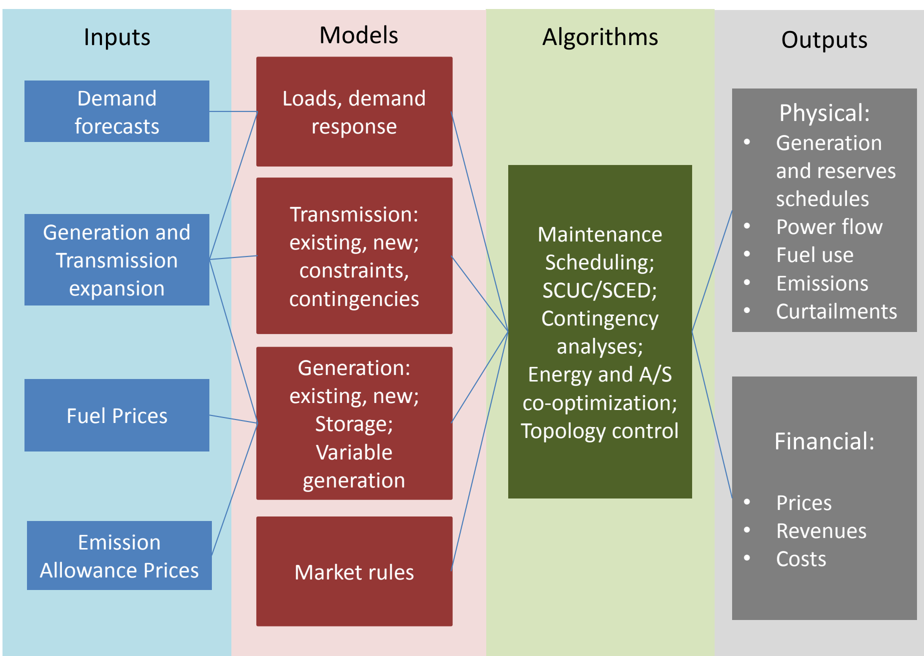
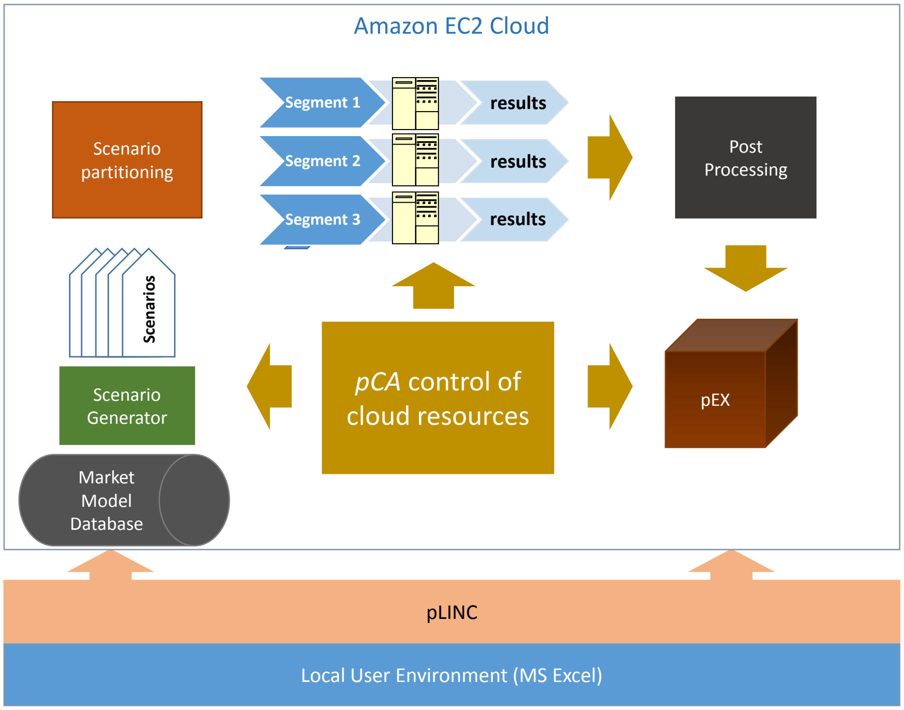


Exhibit 5-3. Architecture of *pCloudAnalytics*



In the PSO modeling used for this project, there is a commitment (next-day) step and a dispatch (real-time) step. In the commitment process, generating units in a region are turned on or kept on in order for the system to have enough generating capacity available to meet the expected peak load and required operating reserves in the region for the next day. PSO then uses the set of committed units to dispatch the system on an hourly real-time basis, whereby committed units throughout the modeled footprint are operated between their minimum and maximum operating points to minimize total production costs. The unit commitment in PSO is formulated as a mixed integer linear programming optimization problem which is solved to the true optima using the commercial Gurobi solver.

5.2.1 Configuration of pCloudAnalytics for AESC 2015

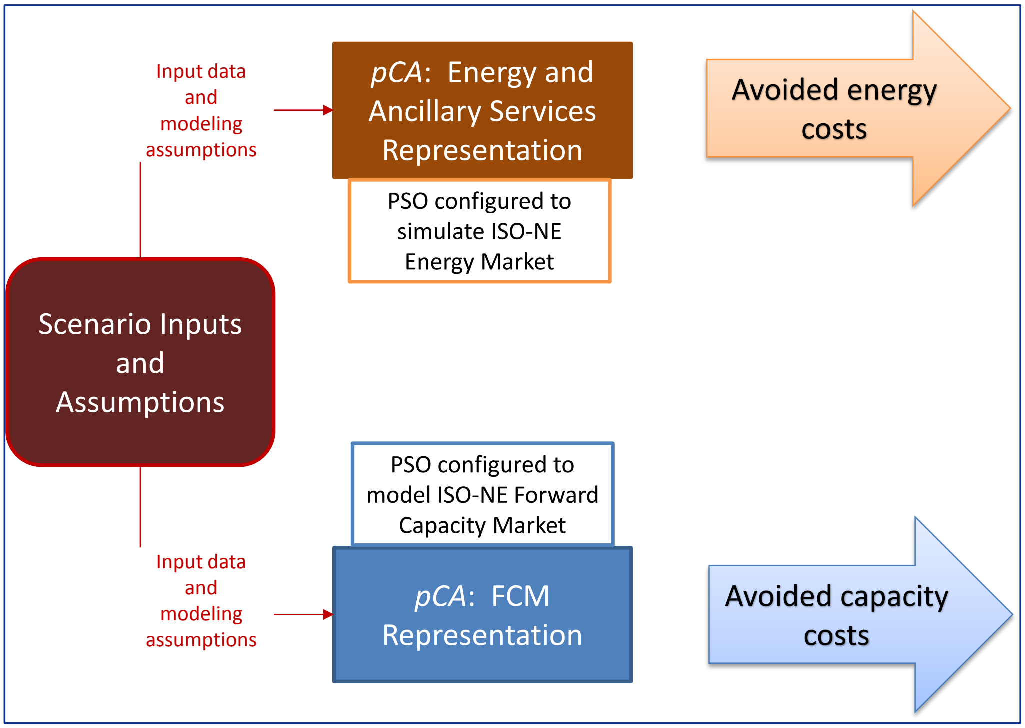
TCR configured *pCloudAnalytics* (pCA) to iteratively model two distinct ISO New England markets: market for energy and ancillary services (E&AS) and the Forward Capacity Market (FCM). As shown in Exhibit 5-4, the E&AS configuration of pCA produces the projection of energy prices while the FCM configuration produces the projection of capacity prices.

The critical element of this analysis is development of input assumptions which are consistent between the two market configurations. To achieve this consistency, two conditions must hold:

- The set of generating units included in the E&AS model should be sufficient to meet system-wide and local resource adequacy requirements. Otherwise, E&AS simulation will yield avoided energy costs that are too high.

- On the other hand, the generating resources modeled in the E&AS configuration should include only those resources that clear in the market in the FCM configuration. Otherwise, E&AS simulations will yield energy costs that are too low.

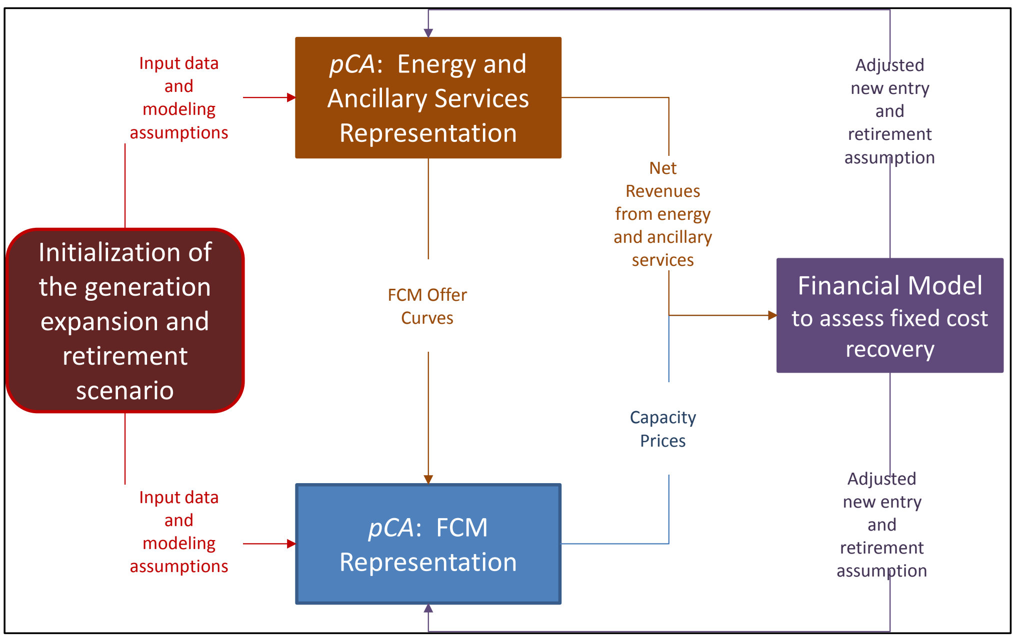
Exhibit 5-4. Use of pCloudAnalytics in AESC 2015



5.2.2 Iterative Use of pCA to develop a Consistent Set of Generating Resources

To develop a consistent set of resources across two markets, TCR ran E&AS and FCM iteratively as shown in Exhibit 5-5.

Exhibit 5-5. Iterative Use of pCA



In the initial iteration, TCR developed a forward-looking capacity balance to make sure that system wide and local resource adequacy requirements are met.

Next, TCR ran its E&AS simulations. TCR used the results of these simulations to project the energy market revenues capacity resources would receive each year. Based on those projected energy revenues, and our projection of the total cost a generating unit would need to recover each year to earn its threshold level of earnings, TCR projected the bids that new units would submit in the FCAs. TCR represents these projected bids as “offer curves” in the FCM model to simulate the outcome of the FCAs. (TCR made this interactive analysis using the results of the E&AS and FCM simulations as inputs to a financial model which it ran for each potential capacity resource addition. The financial model computed the net cash flow of each resource over the modeling horizon.)

- For existing resources the key question is whether the resource can consistently recover its fixed O&M costs given E&AS and FCM revenues. AESC 2015 assumes that if a resource cannot recover its fixed O&M costs for 2-3 subsequent years, it will be removed from the dataset as if retired while a generic new resource will be added to the dataset to maintain capacity balance.

- For potential new resources the key question is whether the resource recovers its fixed O&M and capital cost given E&AS and FCM revenues during the commitment period when the resource first enters the market. If the resource does not recover these costs for a given assumed generating technology and/or load zone, TCR would consider whether the new resource should be placed in a different location or should be of different technology.

After reviewing these changes to the assumed generation mix, TCR did another run of the E&AS model and the FCM model. TCR continued this iterative process until the results met the two consistency conditions described above.

5.3 Input Assumptions Common to E&AS and FCM Modes

This section describes assumptions that are used to simulate the operation of the E&AS market and the Forward Capacity Market (FCM).

5.3.1 Load Forecasts

AESC 2015 ran market simulations for two different load forecasts, a Base Case and a BAU Case. It developed the load forecasts for both Cases through 2023 from ISO New England (ISO NE) forecasts presented in the 2014 Regional System Plan (2014 RSP). The forecasts for 2024 through 2030 are extrapolations using the Compound Aggregation Growth Rates (CAGRs) for 2018 through 2023.

ISO NE presents several load-related forecasts in its 2014 RSP. First, ISO-NE provides an econometric forecast through 2023 of the hypothetical level of electricity consumption that would occur had no energy efficiency measures been installed in the past and if no new energy efficiency measures are installed in the future. energy and peak load by area.

Exhibit 5-6 and Exhibit 5-7 summarize this high or “gross” forecast of annual energy and peak load by area.

Exhibit 5-6: Gross Annual Energy Forecast summary by ISO-NE area

Load Zone	2015 (GWH)	2016 (GWH)	2017 (GWH)	2018 (GWH)	2019 (GWH)	2020 (GWH)	2021 (GWH)	2022 (GWH)	2023 (GWH)	CAGR
CT	34,825	35,250	35,635	35,980	36,290	36,585	36,885	37,185	37,495	0.83%
ME	12,475	12,625	12,730	12,810	12,875	12,945	13,020	13,100	13,175	0.56%
NH	12,575	12,765	12,935	13,085	13,210	13,335	13,455	13,575	13,700	0.92%
NMABO	28,440	28,880	29,265	29,580	29,865	30,145	30,430	30,715	31,000	0.94%
RI	8,850	8,960	9,060	9,150	9,220	9,280	9,340	9,400	9,455	0.66%
SEMA	17,470	17,760	18,005	18,220	18,410	18,595	18,785	18,975	19,170	1.02%
VT	6,790	6,840	6,890	6,935	6,975	7,025	7,070	7,125	7,175	0.68%
WCMA	19,000	19,250	19,465	19,635	19,780	19,925	20,070	20,215	20,360	0.73%
Total	140,425	142,330	143,985	145,395	146,625	147,835	149,055	150,290	151,530	0.83%

Exhibit 5-7: Gross Coincident Summer Peak Load Forecast Summary by ISO-NE area.

Load Zone	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
CT	7510	7630	7740	7830	7900	7970	8035	8105	8165	0.84%
ME	2145	2175	2200	2220	2240	2255	2275	2295	2315	0.84%
NH	2605	2655	2700	2740	2780	2820	2860	2900	2940	1.42%
NMABO	5820	5940	6055	6150	6225	6305	6380	6455	6525	1.19%
RI	1950	1980	2015	2040	2065	2085	2110	2130	2150	1.06%
SEMA	3655	3735	3810	3870	3920	3975	4020	4075	4120	1.26%
VT	1110	1125	1135	1145	1150	1160	1170	1180	1190	0.77%
WCMA	3820	3890	3955	4010	4055	4095	4135	4175	4215	1.00%
Total	28615	29130	29610	30005	30335	30665	30985	31315	31620	1.05%

Source: ISO New England 2014 RSP Forecast

Second, ISO-NE provides a forecast of passive demand resources (PDR) that have cleared in FCAs for power years through May 2018. PDR reduces the level of electric energy consumption that would otherwise have to be supplied from generation resources. PDR includes such resources as energy efficiency and "behind-the meter" distributed generation (DG) used on site at locations that have net metering, which allows power customers who generate their own electricity to feed their excess back into the grid. PDR resources participate in the energy market under normal conditions, and should therefore be accounted for in modeling energy and capacity markets.

Exhibit 5-8. ISO NE Projected Peak Reduction Due to PDR

Load Zone	2014 (MW)	2015 (MW)	2016 (MW)	2017 (MW)
CT	431	420	450	421
ME	145	157	171	184
NH	78	84	86	97
NMBAO	295	343	368	497
RI	92	139	153	179
SEMA	165	190	209	259
VT	110	124	136	132
WCMA	191	227	264	321
Total	**1507**	**1685**	**1839**	**2089**

Exhibit 5-9. ISO NE Projected Annual Energy Use Reduction Due to PDR

Load Zone	2014 (GWH)	2015 (GWH)	2016 (GWH)	2017 (GWH)
CT	2575	2554	2568	2335
ME	871	1013	1104	1180
NH	467	506	523	543
NMBAO	1730	1996	2215	2701
RI	537	717	890	1010
SEMA	909	1074	1201	1395
VT	698	791	878	896
WCMA	1061	1305	1530	1801
Total	**8848**	**9955**	**10909**	**11862**

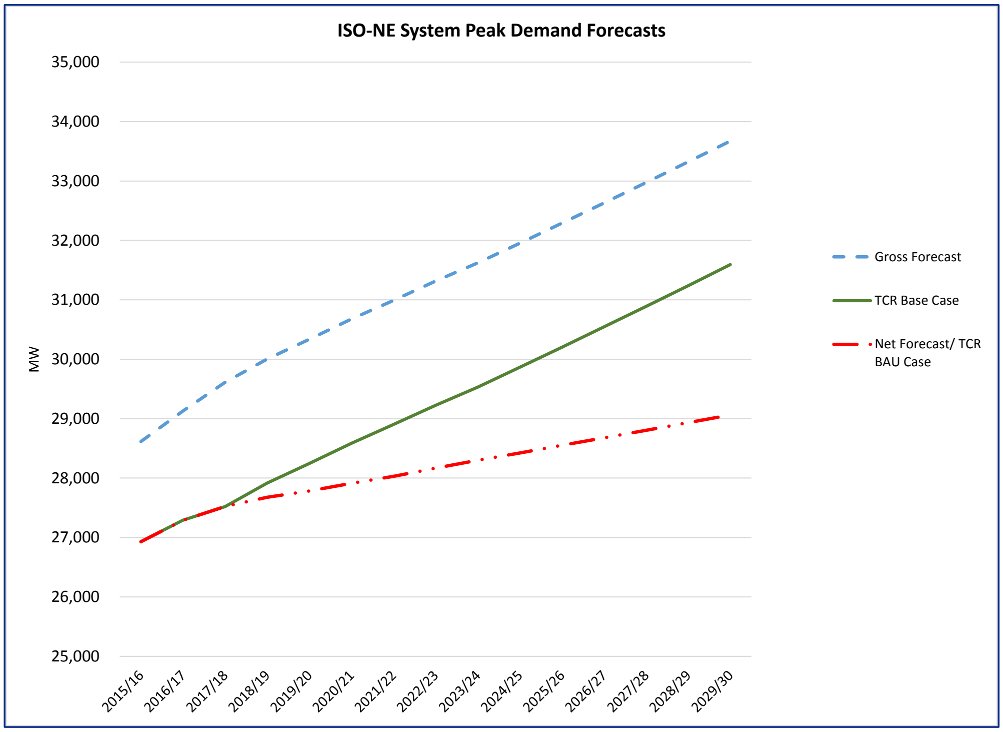
Third, ISO-NE provides a forecast of the level of electricity consumption that it expects to occur through 2023. This lower, or "net", forecast is equal to the gross load forecast minus the PDR through May 2018 and its projection of additional reductions from new ratepayer funded energy efficiency measures implemented from 2018 through 2023. (ISO NE develops its energy-efficiency forecast based on data that each state provides on actual funding and actual reductions.[148] (ISO-NE does not adjust the data it receives from each state. As a result the ISO NE projected reductions for state "A" are consistent with the energy efficiency accounting and cost recovery policies of state A. However, the composition of the projected reductions for state A may differ from those projected for state B due to differences in energy efficiency policies between state A and state B.)

5.3.2 Development of AESC 2015 Load Forecasts

Exhibit 5-10 presents the ISO NE gross forecast of system peak demand, the AESC 2015 Base Case forecast and the ASEC 29015 BAU Case forecast.

[148] ____, ISO New England Energy Efficiency Forecast Report for 2018 to 2023. June 3, 2014.

Exhibit 5-10 ISO New England System Peak Forecasts



The AESC 2015 Base Case forecast through May 2018 is equal to the ISO-NE gross load forecast minus the PDR that have cleared in the FCA through that period. From June 2018 through December 2023 the Base Case forecast is equal to the ISO-NE gross load forecast minus the PDR that cleared in the FCA for 2017/2018. This adjustment is consistent with an assumption of no new EE or DR from 2015 onward. The forecast through this period is consistent with an assumption of no new ratepayer funded EE or DR from 2015 onward, except PDR for which program administrators are financially committed, and with the fact that the measures causing the 2017/18 PDR reductions will continue to have an impact for several more years. From 2024 to 2030 the Base Case load is an extrapolation based on the 2018-2023 CAGR of that forecast. The resulting energy and peak projections are presented in Exhibit 5-11 and Exhibit 5-12.

Exhibit 5-11. AESC 2015 Base Case Annual Energy Forecast

Load Zone	2015 (GWH)	2016 (GWH)	2017 (GWH)	2018 (GWH)	2019 (GWH)	2020 (GWH)	2021 (GWH)	2022 (GWH)	2023 (GWH)	CAGR
CT	32,271	32,682	33,300	33,244	33,554	33,849	34,149	34,449	34,759	0.90%
ME	11,462	11,521	11,550	11,488	11,553	11,623	11,698	11,778	11,853	0.63%
NH	12,069	12,242	12,392	12,466	12,591	12,716	12,836	12,956	13,081	0.97%
NMABO	26,444	26,665	26,564	26,476	26,761	27,041	27,326	27,611	27,896	1.05%
RI	8,133	8,070	8,050	7,999	8,069	8,129	8,189	8,249	8,304	0.75%
SEMA	16,396	16,559	16,610	16,616	16,806	16,991	17,181	17,371	17,566	1.12%

VT	5,999	5,962	5,994	5,914	5,954	6,004	6,049	6,104	6,154	0.80%
WCMA	17,695	17,720	17,664	17,566	17,711	17,856	18,001	18,146	18,291	0.81%
Total	130,469	131,421	132,124	131,769	132,999	134,209	135,429	136,664	137,904	0.91%

Exhibit 5-12. AESC 2015 Base Case Coincident Summer Peak Forecast

Load Zone	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
CT	7090	7180	7319	7409	7479	7549	7614	7684	7744	0.89%
ME	1988	2004	2016	2036	2056	2071	2091	2111	2131	0.92%
NH	2521	2569	2603	2643	2683	2723	2763	2803	2843	1.47%
NMABO	5477	5572	5558	5653	5728	5808	5883	5958	6028	1.29%
RI	1811	1827	1836	1861	1886	1906	1931	1951	1971	1.16%
SEMA	3465	3526	3551	3611	3661	3716	3761	3816	3861	1.35%
VT	986	990	1003	1013	1018	1028	1038	1048	1058	0.87%
WCMA	3593	3626	3634	3689	3734	3774	3814	3854	3894	1.09%
Total	26931	27294	27520	27915	28245	28575	28895	29225	29530	1.13%

The BAU Case forecast is the ISO NE net forecast through 2023 (It is identical to the Base Case through 2018). It reflects the impact of PDR and future energy efficiency. From 2024 to 2030 the BAU Case load is an extrapolation based on the 2018-2023 CAGR of that forecast.

Exhibit 5-13. Net Annual Energy Forecast summary by ISO-NE area. AESC 2015 BAU Case Forecast.

Load Zone	**2015 (GWH)**	**2016 (GWH)**	**2017 (GWH)**	**2018 (GWH)**	**2019 (GWH)**	**2020 (GWH)**	**2021 (GWH)**	**2022 (GWH)**	**2023 (GWH)**	**CAGR**
CT	32,271	32,682	33,300	33,244	33,174	33,111	33,073	33,054	33,064	-0.11%
ME	11,462	11,521	11,550	11,488	11,421	11,369	11,330	11,304	11,280	-0.36%
NH	12,069	12,242	12,392	12,466	12,518	12,574	12,627	12,684	12,749	0.45%
NMABO	26,444	26,665	26,564	26,476	26,384	26,312	26,267	26,244	26,241	-0.18%
RI	8,133	8,070	8,050	7,999	7,937	7,875	7,820	7,774	7,730	-0.68%
SEMA	16,396	16,559	16,610	16,616	16,612	16,615	16,635	16,666	16,712	0.12%
VT	5,999	5,962	5,994	5,914	5,834	5,767	5,702	5,650	5,599	-1.09%
WCMA	17,695	17,720	17,664	17,566	17,459	17,369	17,295	17,235	17,188	-0.43%
Total	130,469	131,421	132,124	131,769	131,339	130,992	130,749	130,611	130,563	-0.18%

Exhibit 5-14. Net Coincident Summer Peak Load Forecast summary by ISO-NE area. AESC 2015 BAU Case Forecast.

Load Zone	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
CT	7,090	7,180	7,319	7,360	7,384	7,411	7,435	7,466	7,489	0.35%
ME	1,988	2,004	2,016	2,016	2,017	2,015	2,019	2,024	2,030	0.14%
NH	2,521	2,569	2,603	2,631	2,659	2,688	2,717	2,747	2,777	1.09%
NMABO	5,477	5,572	5,558	5,598	5,622	5,654	5,685	5,718	5,749	0.53%
RI	1,811	1,827	1,836	1,839	1,844	1,845	1,852	1,856	1,860	0.23%
SEMA	3,465	3,526	3,551	3,582	3,606	3,636	3,657	3,691	3,715	0.73%
VT	986	990	1,003	996	984	977	972	967	962	-0.69%
WCMA	3,593	3,626	3,634	3,654	3,666	3,675	3,686	3,699	3714	0.33%
Total	26,931	27,294	27,520	27,676	27,782	27,901	28,023	28,168	28296	0.44%

5.3.3 Development of Hourly Load Shapes for AESC 2015 Load Forecasts

RSP 2014 provides projections of summer and winter peak, and annual energy, by load zone. However, to simulate the ISO New England market on an hourly basis, PSO requires an hourly load shape for each simulated time frame and area modeled. AESC 2015 constructed load shapes for each area from the following data:

- Template hourly load profiles
- Annual energy and summer/winter peak forecasts for the study period

AESC 2015 uses 2006 historical load shapes by zone as a template for load profiles. AESC 2015 selected 2006 to ensure the load profiles were synchronized with the most recent modeling of wind generation patterns in New England available from the National Renewable Energy Laboratory (NREL), which is 2006. To develop hourly load forecast for future years, pCA load algorithms first calendar shifts the template load profile to align days of the week and NERC holidays between 2006 and the forecast year. pCA algorithms then modify calendar shifted template profiles in such a manner that the resulting load shape exhibits the hourly pattern close to that of the template profile while the total energy for the year match the energy forecast and summer and winter peaks match the summer and winter peak forecast.

5.3.4 Interchange Data

pCA models New England interchanges with neighboring regions, i.e., the Canadian provinces of New Brunswick and Quebec and the New York ISO, using ISO-NE reported historical hourly interchange schedules for calendar year 2006. Similarly to load profiles, interchange flow data are calendar shifted for each forecast year and therefore remain synchronized with load pattern in ISO New England. Explicitly distinguished interchange schedules include:

- New Brunswick Interface at Keswig external node

- Phases I and II Interface with Hydro Quebec via HVDC
- Highgate interface with Hydro Quebec via HVDC
- Cross Sound Cable HVDC interconnection with NYSIO
- Roseton AC interface with NYSIO

These interfaces are mapped to electrical points of interconnection with the ISO New England in the power flow model used for pCA simulations.

5.3.5 Transmission

The geographic footprint PSO modeled encompasses the six New England states: Maine, Massachusetts, New Hampshire, Vermont, Rhode Island, and Connecticut, whose electricity movement and wholesale markets are coordinated by ISO-NE.

The physical location of all network resources is organized using substation and node mapping. The transmission topology is modeled based on the 2011 FERC 715 power flow fillings for summer peak 2016. NEG verified the power flow model against the ISO-NE queue to make sure that essential transmission projects are represented in the power flow case. Generators are mapped to bus bars/electrical nodes (eNodes). Bus bars are mapped to substations and substations are in turn mapped to ISO New England SMD Zones. The mapping of bus bars to zones allows PSO to allocate hourly area load forecasts to load busses in proportion to the initial state from the power flow.

In determining a representative list of transmission constraints to monitor, NEG includes all major ISO-NE interfaces and frequently binding constraints, as reported by ISO-NE. Key interface limits are specified in Exhibit 5-15. For certain interfaces, limits obtained from the ISO New England's FERC Form 715 filing represent Critical Energy Infrastructure Information (CEII) and are not shown in that table. All single line normal and emergency ratings are taken directly from the power flow.

Exhibit 5-15: Interface Limits

Interface	Max MW	Min MW
New England – Boston*	4850	No Limit
Connecticut Import *	3050/2950 [a]	No Limit
Maine - New Hampshire *	1600 /1900 [b]	No Limit
New England East – West *	2800/ 3500 [a]	-1000/ -2200 [a]
Newington Area Generation **	CEII Protected	No Limit
New Hampshire-Maine **	CEII Protected	No Limit
Northern Vermont Import **	CEII Protected	No Limit
Orrington – South *	1200/1325 [b]	No Limit
Rhode Island Import **	CEII Protected	No Limit
Surowiec – South *	1150/ 1500 [b]	No Limit
Western Connecticut Import **	CEII Protected	No Limit
North – South *	2700	No Limit
Sandy Pond – South **	CEII Protected	No Limit
New England - Southwest Connecticut *	3200	No Limit
New England - Norwalk Stamford **	CEII Protected	No Limit
Northern New England Scobie 345kV - Scobie + 394 **	CEII Protected	No Limit

Notes:

[a] New limit effective 2017

[b] New limit effective 2015

Sources:

*ISO New England, Transmission Interface Transfer Capabilities: 2014 Regional System Plan Assumptions, Part 3, March 17, 2014. Available online at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf

The 2014 RSP describes a considerable number of "Elective Transmission Upgrades" that are currently under review by ISO New England. These include a number of major proposed AC and HVDC projects to increase transfer capabilities between New England and the Canadian provinces of Quebec and New Brunswick, as well as between the Maine Zone and major load centers in New England. One of the Elective Transmission Upgrades is Northern Pass Transmission (NPT), which received Proposed Plan Application approval from ISO New England on December 31, 2013.

Based upon its review, AESC 2015 did not assume any of these proposed projects in its Base or BAU Cases because of the high degree of uncertainty regarding the key assumptions require to model any of them. Those key assumptions include whether the project will receive approval at the Federal and state levels, when it might come into service, the location of its ultimate interconnection points within New England and the technical and economic characteristics of the electric energy the project would deliver into the New England market.

5.3.6 Generating Unit Retirements and Additions

Exhibit 5-16 summarizes the generation retirements approved by ISO-NE and assumed in our simulations.

Exhibit 5-16: Approved retirements in ISO-NE

Full Name	Retire Date	Area	Capacity (MW)
Mt. Tom	6/2/2014	WCMA	145
Salem Harbor 3	6/1/2014	NEMA	150
Salem Harbor 4	6/1/2014	NEMA	437
VT Yankee Nuclear	12/31/2014	VT	620
Brayton Point 1-4	6/1/2017	SEMA	1,534
Total			**2,886**

Over the AESC 2015 time horizon, new generation resources will be needed to satisfy renewable portfolio standards and resource adequacy requirements. Since pCA is not a capacity expansion model, these additions are exogenous. Section 5.6 provides the AESC 2015 assumptions for renewable resource additions to comply Renewable Portfolio Standard (RPS) requirements. Exhibit 5-17 summarizes known near-term new generation additions included in the pCA database. These are projects listed in ISO-NE's interconnection queue which are either under construction or which have major interconnection studies completed.

Exhibit 5-17. New Generation Additions

Name	Unit	Fuel	SumMW	OpDate	Zone	ST
Cape Wind Turbine Generators	WT	WND	462	12/31/2016	SEMA	MA
Brockton Combined Cycle	CC	NG DFO	332	4/19/2017	SEMA	MA
Oakfield II Wind - Keene Road	WT	WND	147.6	12/31/2015	ME	ME
Palmer Renewable Energy	ST	WDS	36.7	7/15/2017	WCMA	MA
Saddleback Ridge Wind Project	WT	WND	33	12/2/2014	ME	ME
Canton Mountain Winds	WT	WND	19.25	11/1/2016	ME	ME
Fair Haven Biomass	ST	WDS	33	3/30/2016	VT	VT
Kendall #3 Back Pressure Steam Turbine	ST	NG DFO	28.5	12/31/2015	NMABO	MA
Pisgah Mountain	WT	WND	9	11/1/2015	ME	ME
CPV Towantic Energy Center	CC	NG DFO	745	6/1/2018	CT	CT
Weston Station Uprate U4	HD	WAT	14.81	11/25/2015	ME	ME
Weston Station AVR Replacement U2-4	HD	WAT	14.81	10/3/2015	ME	ME
Berkshire Wind Increase	WT	WND	19.8	1/1/2017	WCMA	MA
MATEP -3rd CTG	CT	DFO NG	100	6/1/2017	NMABO	MA
Jericho Wind	WT	WND	8.55	6/30/2015	NH	NH
Footprint Combined Cycle Unit	CC	NG	715.6	3/1/2017	NMABO	MA
Northfield Mt Upgrade #1	PS	WAT	295	6/1/2016	WCMA	MA

5.3.7 Generating Unit Operational Characteristics

Thermal Units

Thermal generation characteristics are generally determined by unit type. These include: heat rate curve shape, non-fuel operation and maintenance costs, startup costs, forced and planned outage rates, minimum up and down times, and quick start, regulation and spinning reserve capabilities.

Capacity ratings were obtained from SNL Financial. Fully Loaded Heat Rates (FLHRs), forced outage rates and planned outage rates were not available from ISO-NE. Instead, NEG used information by similar unit type as obtained from both the North American Electric Reliability Corporation (NERC) Generating Availability Report and power industry data provided by SNL Financial. Similarly, given the lack of information from ISO-NE on Variable O&M costs, NEG used its assumptions by unit type for existing and planned units that are consistent with modeling these units in other markets.

Due to the large number of small generating units, NEG aggregates all units below 20 MWs by type and size into a smaller set of units. Full load heat rates for the aggregates are calculated as the average of the individual units and all other parameters are inherited from the unit type.

Heat rate curves are modeled as a function of full load heat rate ("FLHR") by unit type:

- CT: Single block at 100% capacity at 100% of FLHR.
- CC: 4 blocks: 50% capacity at 113% of FLHR, 67% capacity at 75% of FLHR, 83% capacity at 86% of FLHR, and 100% capacity at 100% of FLHR. As an example, for a 500 MW CC with a 7000 Btu/KWh FLHR, the minimum load block would be 250 MW at a heat rate of 7910, the 2nd step would be 85 MW at a heat rate of 5250, the 3rd step would be 80 MW at a heat rate of 6020, and the 4th step would be 85 MW at a heat rate of 7000.
- Steam Coal for all MW: 4 blocks: 50% capacity at 106% of FLHR, 65% capacity at 90%, 95% capacity at 95% FLHR, and 100% capacity at 100% FLHR.
- Steam Gas for all MW: 4 blocks: 25% capacity at 118% of FLHR, 50% capacity at 90%, 80% capacity at 95% FLHR, and 100% capacity at 100% FLHR.

Exhibit 5-18 below shows other assumptions by type for thermal plants. The abbreviations in the Unit Type column are structured as follows: First 2-3 characters identify the technology type, the next 1-2 characters identify the fuel used (**g**as, **o**il, **c**oal, **r**efuse) and the numbers identify the size of generating units mapped to that type.

Exhibit 5-18. Thermal Unit Assumptions by Type and Size

Unit Type	Min Up Time (h)	Min Down Time (h)	EFORd	VOM ($/MWh)	Startup Cost ($/MW-start)	Startup Failure Rate
CCg100	6	8	4.35	2.5	35	0.01
CTb50 (1-19MW)	1	1	19.73	0	35	0.06
CTb50 (20-49MW)	1	1	10.56	0	35	0.03
CTg50 (1-19MW)	1	1	19.73	10	0	0.06
CTg50 (20-49MW)	1	1	10.56	10	0	0.03
CTg50+	1	1	7.25	10	0	0.02
ICr50 (0-50MW)	10	8	19.73	2	40	0.06
NUC-PWR (400-799MW)	164	164	2.58	0	35	0
NUC-BWR (400-799MW)	164	164	3.24	0	35	0.02
NUC-PWR (800-999MW)	164	164	4.34	0	35	0.01
NUC-BWR (800-999MW)	164	164	1.8	0	35	0.05
NUC-PWR (1000+MW)	164	164	2.88	0	35	0.004
NUC-BWR (1000+MW)	164	164	2.82	0	35	0.025
STc100 (0-100MW)	24	12	10.64	5	45	0.02
STc200 (100-199MW)	24	12	6.3	4	45	0.03
STc300 (200-299MW)	24	12	7.1	4	45	0.03
STc400 (300-399MW)	24	12	6.85	3	45	0.04
STc600 (400-599MW)	24	12	7.82	3	45	0.06
STc800 (600-799MW)	24	12	6.71	2	45	0.03
STc1000 (800-999MW)	24	12	4.65	2	45	0.04
STc1000+ (1000+MW)	24	12	8.62	2	45	0.06
STg100 (0-100MW)	10	8	12.55	6	40	0.009
STg200+ (100-200MW)	10	8	7.28	5	40	0.01
STgo300 (200-299MW)	10	8	6.67	4	40	0.02
STgo400 (300-399MW)	10	8	5.41	4	40	0.02
STgo500 (400-599MW)	10	8	9.06	4	40	0.03
STgo600 (600-799MW)	10	8	9.48	3	40	0.05
STgo600+	10	8	1.93	3	40	0.02
STo100 (1-99MW)	10	8	3.54	6	40	0.006
STo200 (0-200MW)	10	8	5.6	5	40	0.02
STo600 (200-299MW)	10	8	10.59	4	40	0.02
STo600 (300-399MW)	10	8	4.53	4	40	0.02
STo600 (400-599MW)	10	8	4.45	4	40	0.01
STo600+ (600-799MW)	10	8	41.26	3	40	0.03
STo600+ (800-999MW)	10	8	14.36	3	40	0.09
STr	10	8	10.26	2	40	0.02

Source: NEG Analysis

Nuclear Units

Nuclear plants are assumed to run when available, and have minimum up and down times of approximately one week (164 hours). Capacity ratings, planned outage rates and forced outage rates are the same as those obtained from the NERC Generating Availability Report. The values represent a normalized annual rate that does not directly capture the timing of refueling outages. In general, nuclear facilities are treated as must run units. Production costs were modeled using NEG input assumptions for fuel and variable O&M.

Hydro and Pumped Storage

Hydro units are specified as a daily pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. Of those, NEG assumed that hydro plants use 40% of the daily energy at the same level in each hour of the day. The remaining 60% of the daily energy is optimally scheduled by PSO to minimize system-wide production costs. Daily energy was estimated using plant specific capacity factors under the assumption that hydro conditions do not vary significantly across seasons.

PSO fully optimizes pumped storage operation schedules.

Renewable Energy Resources

We model wind, solar, and biomass generating capacity.[149] Technology-specific assumptions for each are described below.

Wind

Onshore and offshore wind generation is represented in the model using hourly generation profiles developed using the 10-minute wind power output profiles, averaged hourly, which are obtained from the National Renewable Energy Laboratory (NREL).[150] The pCA database stores wind generation profiles provided by NREL based on 2006 weather data, so as to be consistent with the 2006 load profiles used in the analysis. Each wind site in ISO-NE is mapped to the nearest NREL wind site to obtain the appropriate hourly schedule. The resulting schedule is scaled to the installed capacity of the corresponding wind site and then calendar-shifted for each forecast year making it synchronized with load profiles and interchange schedules.

Solar Photovoltaics

PV generation is represented in the model using hourly generation profiles for three system sizes in each of the six states (for a total of 18 profiles). The profiles were developed using the NREL SAM PV Watts

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[149] The modeling of hydro resources is discussed in the previous section.

[150] National Renewable Energy Laboratory (US), "Wind Systems Integration - Eastern Wind Integration and Transmission Study," nrel.gov, 2010. [Online]. Available at: http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html

module, with 2006 weather data files obtained from NREL. The array types (fixed open rack or roof mount) and tilt were selected based on the system size and location to conform to typical practice in New England. The hourly profiles were adjusted so that the capacity factors matched those used by ISO New England in its PV forecast,[151] listed below in Exhibit 5-19.

Exhibit 5-19. PV Capacity Factor Assumptions

	CT	MA	ME	NH	RI	VT
Capacity Factor (AC)	16.0%	15.4%	15.4%	15.1%	15.5%	14.0%

Biomass is modeled as dispatchable generation subject to generation technology parameters and fuel prices.

5.3.8 Operating Reserves

AESC 2015 modelled four types of Ancillary Services: Regulation, Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve and Thirty-Minute Operating Reserve. Reserves are cascading – excess regulation counts toward spinning reserves. Excess spinning reserves counts toward Non-spinning. Spinning reserve requirements are considered bi-directional. Non-Spinning reserves can be provided by offline peaking capacity and can handle upward ramping only.

- Regulation must be provided by online resources at the level of ramp rate (in MW/min) limited by a 5 minute activation time.
- Ten-Minute Spinning Reserve (TMSR) must be provided by online resources at the level of ramp rate (MW/min) limited by a 10 minute activation time. Hydro can provide Synchronized reserve up to 50% of its dispatch range.
- Ten-Minute Non-Spinning Reserve (TMSNR) is provided by offline resources capable of supplying energy within 10 minutes of notices. TMSNR can only be provided by quick start capable CTs and Internal Combustion (IC) units.
- Thirty-Minute Operating Reserve (TMOR) can be provided by either on-line or off-line resources with less than 30 minutes activation time.

Hydro generators are assumed to provide regulation and reserves for up to 50% of available dispatch range. Nuclear and wind provide no ancillary services.

[151] ISO New England PV Energy Forecast Update, available at: http://www.iso-ne.com/static-assets/documents/2014/09/pv_energy_frcst_update_09152014.pdf.

Exhibit 5-200 below summarizes reserve requirements in ISO-NE.

Exhibit 5-20 ISO-NE Regulation and Reserve Requirements

Reserve Type	Requirement (MW)
Regulation	Hourly schedule per ISO-NE requirements
Ten min spinning reserves	820
Ten min non-spinning reserves	820
Thirty min operating reserves	750

5.3.9 Emission Rates and Allowances

Emission rates for most plants were obtained from historical SNL emission rate data. For plants for which there were no emission rates (i.e., those under construction) generic EIA emission data were used.

Emission allowance price assumptions are presented in Chapter 4.

5.4 Capacity Market-Specific Modeling Assumptions

5.4.1 Projection of System-Wide Installed Capacity Requirements

Exhibit 5-21 below summarizes actual ICR through 2017/18 (FCA 8) and the AESC 2015 projections.

Exhibit 5-21. Base Case Projection of System-Wide ICRs

	ISO New England Data[152]				Projection					
Period	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
FCA	5	6	7	8	9	10	11	12	13	14
Gross 50/50 Peak (MW)	29,025	29,380	29,400	29,790	30,005	30,335	30,675	30,990	31,315	31,620
ICR (MW)	34,154	34,498	34,023	34,922	35,109	35,495	35,893	36,262	36,642	36,999
Margin	17.67%	17.42%	15.72%	17.23%	17.01%	17.01%	17.01%	17.01%	17.01%	17.01%
HQ ICC (MW)	954	1,042	1,055	1,068	1,068	1,068	1,068	1,068	1,068	1,068
Net ICR (MW)	33,200	33,456	32,968	33,854	34,041	34,427	34,825	35,194	35,574	35,931

[152] ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit studies for 2014/15, 2015/16, 2016/17 and 2017/18 capability periods

Starting with the data provided in the four most recent ICR studies, we estimated implied reserve margin requirements – a difference between ICR and projected summer peak demand divided by the peak demand. A simple average of these margins is 17.01%. AESC 2015 assumed ISO NE would continue to require this level of reserve margin. AESC 2015 also assumes import capacity from Hydro Quebec will remain at the level of 1068 MW and computed the resulting net ICRs.

5.4.2 Projection of Local Sourcing Requirements (LSRs) for NEMA /Boston and Connecticut Import Constrained Zones

Local Sourcing Requirements are minimum levels of installed capacity that must be procured within an import-constrained zone. There are two currently recognized import-constrained zones in New England – NEMA/Boston and Connecticut. Exhibit 5-22 summarizes the AESC 2015 projection of Local Sourcing Requirements for import-constrained zones.

Exhibit 5-22 Projection of LSRs for Import Constrained Zones

	ISO NE Data			Projection					
Period	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**
NEMA/Boston									
90/10 Peak	6,530	6,520	6,745	6,615	6,700	6,785	6,865	6,950	7,025
N-1 Import Limit	4,850	4,850	4,850	4,850	4,850	4,850	4,850	4,850	4,850
LSR	3,288	3,209	3,427	3,329	3,434	3,540	3,638	3,744	3,836
Margin	24.6%	23.6%	22.7%	23.6%	23.6%	23.6%	23.6%	23.6%	23.6%
Connecticut									
90/10 Peak	8,250	8,201	8,330	8,530	8,605	8,680	8,750	8,825	8,890
N-1 Import Limit	2,600	2,600	2,800	2,950	2,950	2,950	2,950	2,950	2,950
LSR	7,542	7,603	7,319	7,537	7,629	7,721	7,807	7,900	7,979
Margin	22.9%	24.4%	21.5%	22.9%	22.9%	22.9%	22.9%	22.9%	22.9%

Starting with the data provided in the three most recent ICR studies[153], we estimated implied reserve margin requirements for import-constrained zones. For each zone, the implied reserve margin was computed as a difference between the sum of LSR and N-1 contingency import limit into the zone and the 90/10 peak demand in that zone divided by the 90/10 peak demand. 90/10 peak demand is the ISO New England estimated summer peak which is likely to occur under the 1 in 10 years most critical weather conditions. For each zone, AESC 2015 computed a simple average of that zone's margin (23.6%

[153] ICR study for 2014/15 did not contain sufficient details for this analysis and was not used.

for NEMA Boston and 22.9% for Connecticut) and assumed that this margin will persist in the future. Using this assumption, AESC 2015 projected future LSR values for import constraint zones.

5.4.3 Projection of Maximum Capacity Limit (MCL) for Maine

A Maximum Capacity Limit is the maximum level of installed capacity that can be procured within the export constrained zone. Main is the only export constrained zone in New England. Exhibit 5-233 below summarizes the AESC 2015 projection of the Maximum Capacity Limit for the Maine export constrained zone. Starting with the data provided in the four most recent ICR studies, we estimated ratio of the MCL determined by ISO New England in that period over the sum of the peak demand in Maine and Maine export Limit. AESC 2015 computed the average ratio for this four-year period, 94.4% and assumed that that ratio would persist in the future. Based on that assumption and using ISO New England's forecast of summer peak demand for the Maine zone, AESC 2015 developed projections for the MCL value.

Exhibit 5-23. Projection of MCL for the Maine Zone

	ISO NE Data				Projection					
Period	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**
Peak	2,050	2,150	2,160	2,200	2,220	2,240	2,255	2,275	2,295	2,315
Export Limit	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
MCL	3,702	3,888	3,709	3,960	3,890	3,909	3,923	3,942	3,961	3,980
Ratio	93.7%	96.0%	91.4%	96.6%	94.4%	94.4%	94.4%	94.4%	94.4%	94.4%

5.4.4 PDR Levels

PDR levels used in the Base Case and BAU Cases are summarized in Exhibit 5-24 below.

Exhibit 5-24. PDR levels used in modeling FCA

BAU	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
ISO-NE	2328	2553	2764	2962	3148	3322
CT	470	516	559	600	639	676
NMABO	552	603	651	695	737	776
ME	204	223	240	256	271	285
Base	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
ISO-NE	2089	2089	2089	2089	2089	2089
CT	421	421	421	421	421	421
NMABO	497	497	497	497	497	497
ME	184	184	184	184	184	184

Demand Curve Assumptions

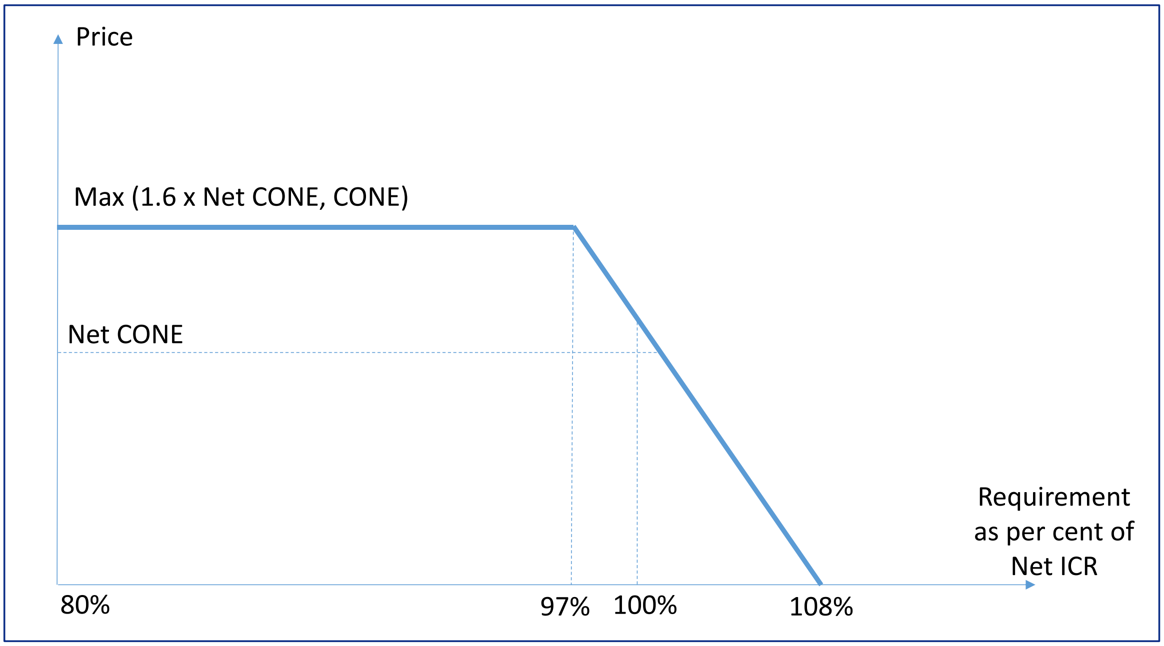
Starting with FCA9 (2018/19 Commitment Period) ISO New England plans to incorporate sloped demand curves into the FCM market design. Introduction of sloped demand curves will significantly impact the capacity price formation mechanism by making capacity prices less volatile in response to changes in reserve margins.

The introduction of demand curves will be implemented in two phases. First, starting with FCA9 (2018/19 commitment period auctioned in 2015) ISO New England will implement only a system-wide demand curve. Second, starting with FCA10, sloped demand curves will be introduced for constrained capacity zones. The system-side demand curve has already been approved by FERC. The design of demand curves for constrained capacity zones is still ongoing. However, the consensus appears to be emerging with ISO New England presenting a revised design in which it agrees with the proposal developed by the New England State Committee on Electricity (NESCOE)[154]. AESC 2015 modeled the FCM market using the system-wide and zone-specific demand curves described below.

Exhibit 5-25 depicts the system-wide sloped demand curve. The curve expresses the system-wide capacity price as a function of the relative level of supply expressed as a percent of Net ICR. The price floor is zero and the price cap is the maximum between 1.6 times of Net CONE and CONE (CONE stands for the Cost of New Entry).

[154] Presentation of Matt Brewster of ISO New England to the NEPOOL Markets Committee, December 9-10, 2014. Available online at http://www.iso-ne.com/static-assets/documents/2014/12/a10a_iso_presentation_12_10_14.pptx

Exhibit 5-25. System-Wide Sloped Demand Curve



Along the demand curve, the price reaches the cap when the supply falls below 97% of Net ICR and falls to zero when supply exceeds 108% of Net ICR. AESC 2015 assumes the net ICR values for each commitment period will be those specified in Exhibit 5-21.

The proposed CONE and Net CONE values, shown in Exhibit 5-26 are[155]

Exhibit 5-26. CONE and Net CONE Assumptions

Parameter	Value in real 2018 $/kW-month	Value (in real 2015 $/kW-year)
CONE	14.04	159.32
Net CONE	11.08	132.96
1.6 x Net CONE	16.672	212.74

Demand curves for import and export constrained zones are shown in Exhibit 5-27 and Exhibit 5-28, respectively. Structurally these curves are similar to the system-wide curve using the same 97% and 108% parameters. For import-constrained zone, the relationship between the price and quantity also factors in the Total Transfer Capability (import limit) into the zone. For the Maine export constrained zone, the curve is defined in terms of MCL as opposed to the Net ICR used in the definition of the system-wide curve but uses the same coefficients of 97% and 108%.

[155] "Testimony of Samuel A. Newell and Christopher D. Ungate on behalf of ISO New England, Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve." April 1, 2014

Exhibit 5-27. Demand Curve for Import Constrained Zone

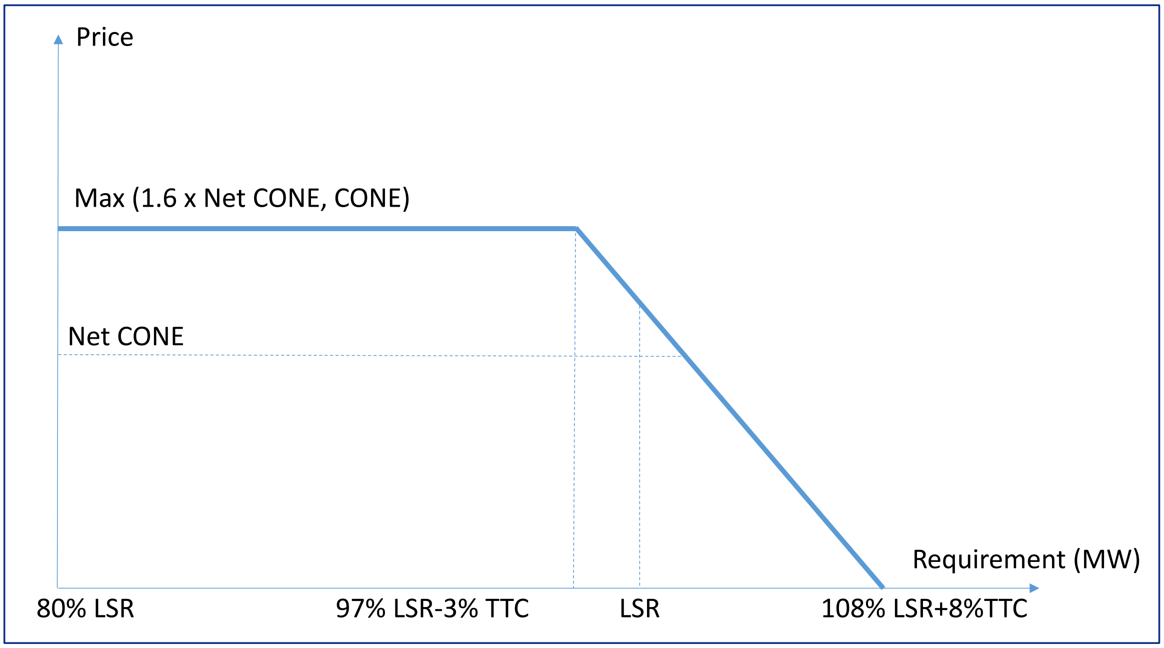
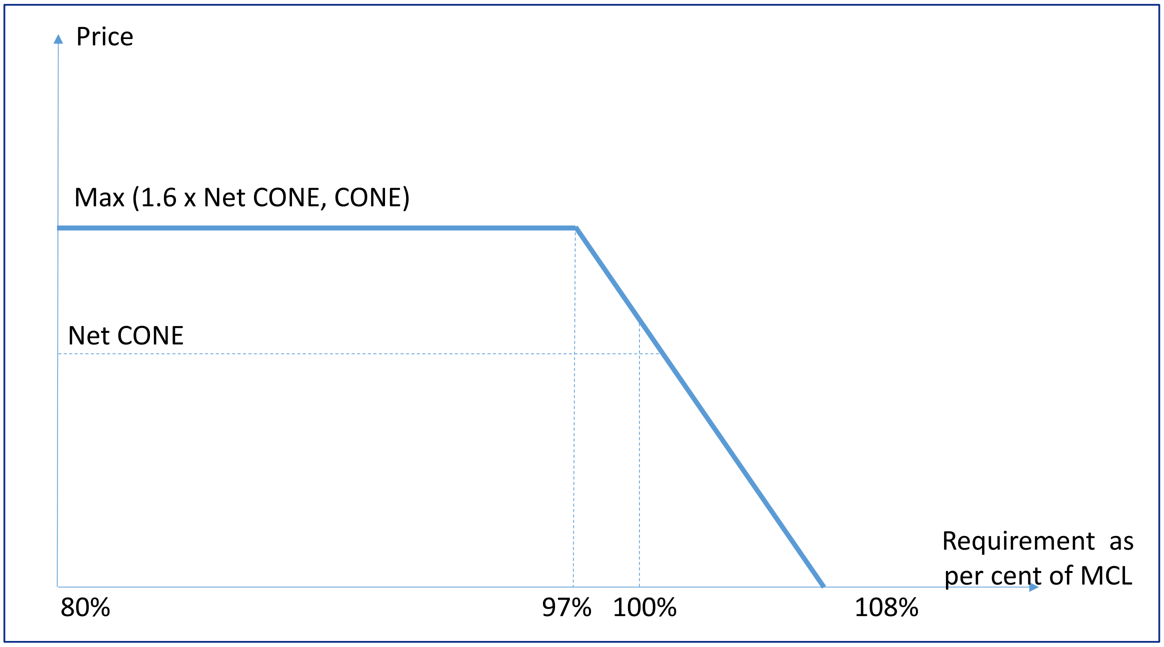


Exhibit 5-28. Demand Curve for Export Constrained Zone



Supply Offers to the FCM

AESC 2015 assumes that generators will set their offers to the FCM at a level which would recover their estimate of the revenue shortfall between the total revenues they require and the net E&AS revenues they expect to receive (i.e., gross E&AS revenues minus their variable operating costs)). The total revenues they require is based on their capital and total operating costs. The net revenues they expect from the energy market is their estimated operating margin from selling energy and ancillary services.

- TCR estimated the offers of existing generators as the difference between estimates of their fixed O&M costs and their net margins per kW of installed capacity per our modeling of the energy market. (We excluded their capital costs since those are "sunk" costs)
- TCR estimated offers from new generators, those to come online during the commitment period, as the difference between the sum of the annualized capital cost and fixed O&M costs and net margins per kW of installed capacity.

The AESC 2015 assumptions for fixed O&M costs of existing generating units are generic by unit type as shown in Exhibit 5-29. These assumptions were reviewed and approved by the stakeholders of the Eastern Interconnection Planning Collaborative **(**EIPC) Phase I study.

Exhibit 5-29. Fixed O&M Assumptions by Unit Type

Unit Type	FOM ($/kW-yr)
STc	52.93
CCg *	32.58
CTg *	18.24
CTo/IC *	18.24
STog	40.78
Nuclear	123.78
Hydro	15.63
PSH	26.06
PV	16.09
Solar Thermal	66.21
Wind Onshore	37.56
Biomass	35.18
Landfill Gas	132.43

Notes:
*Combined Cycle (CC) and Combustion Turbine (CT) assumptions are per "Testimony of Samuel A. Newell and Christopher D. Ungate on behalf of ISO New England, Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve." April 1, 2014

Source:
EIPC Online, http://www.eipconline.com/uploads/MRN-NEEM_Modeling_Assumptions_Draft_Jan_25_2011_Input_Tables_Exhibits.xls

AESC 2015 assumptions with respect to capital costs of new generating units are summarized in Exhibit 5-30 below. For gas fired generating technology AESC 2015 used cost assumptions that are consistent with parameters used to develop CONE estimates and provided in the Brattle Group and Sargent & Lundy study. For other technologies capital cost assumptions are per 2013 EIA Capital Cost Estimates. The EIA study provides only overnight capital costs. To convert overnight costs to annualized capital costs AESC 2015 used Fixed Charge Rates applied in the EIPC study.

Exhibit 5-30. Capital Cost Assumptions.

Unit Type	Annualized Capital Costs ($.kW-yr)
STc *	360.42
CCg **	131.52
CTg **	93.17
CTo/IC **	93.17
Hydro *	366.36
PSH *	659.84
PV *	616.79
Solar Thermal *	632.27
Wind OnShore *	276.14
Wind Offshore *	777.39
Biomass *	504.65
Landfill Gas *	315.07

Sources:
* EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants." April 2013.
** "Testimony of Samuel A. Newell and Christopher D. Ungate on behalf of ISO New England, Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve." April 1, 2014

Contribution of Variable Resources toward ICAP Requirements

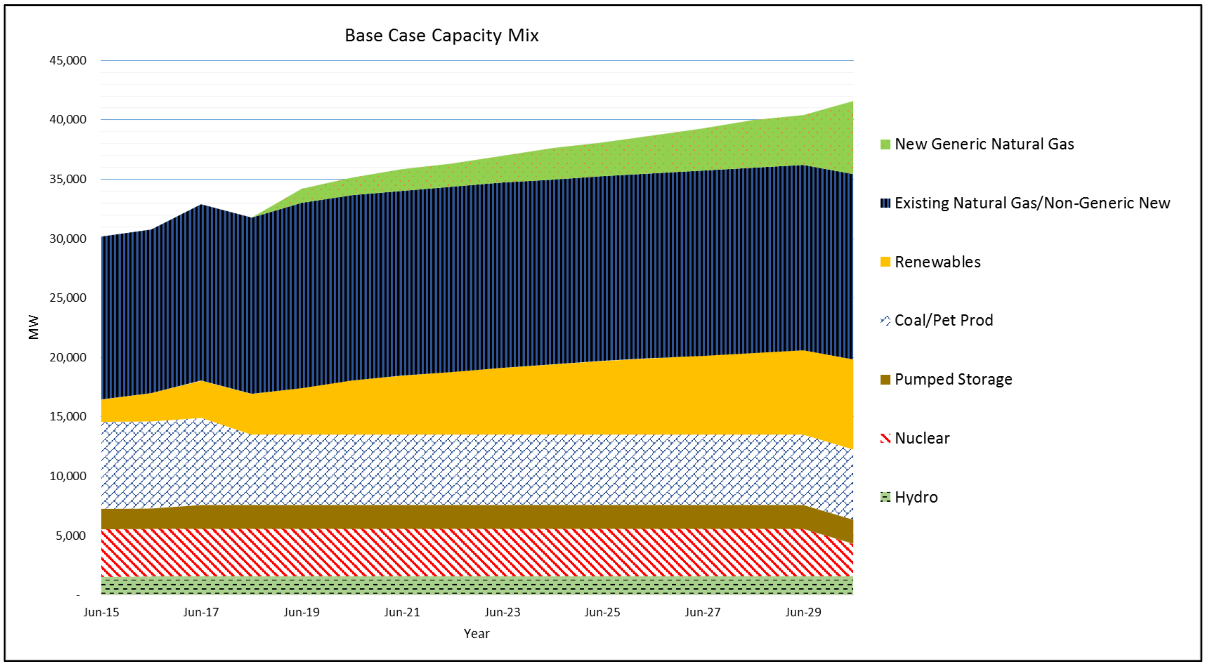
To model the contribution of variable resources such as wind and solar toward ICAP requirements, AESC 2015 followed ISO-NE Market Rule III.13.1.2.2.2.2. According to this rule, Summer Qualified Capacity (contribution to ICAP) should be set as the median of the intermittent source's net output during summer reliability hours (14:00 – 18:00). For each variable resource modeled AESC 2015 used the assumed resource hourly profile to compute the specified median output.

5.5 BASE CASE Projections

5.5.1 Forecast of Capacity and Capacity Prices

The projected level and mix of capacity in the Base Case is presented in Exhibit 5-31. New capacity additions include renewable resources to comply with RPS requirements, as well as new natural gas generators added to meet energy and reserve margin requirements. A substantial portion of the existing oil (Pet Prod) and coal capacity is forecast to retire by 2025. Because of the relatively high price of oil compared to other fuels, these generating plants are rarely dispatched.

Exhibit 5-31. Base Case Capacity by Technology (MW)



Results and Comparison to AESC 2013 Base Case Forecast

The capacity market model explicitly incorporated constraints and demand curves for NEMA-Boston, Connecticut and Maine zones. The modeling results did not show any capacity prices differences between those zones and Rest of Pool.

Exhibit 5-32 compares the AESC 2015 Base Case forecast of capacity prices to the AESC 2013 forecast. The Exhibit presents forecasts of prices by power year (June through May), and by calendar year. On a 15 year levelized basis, the AESC 2015 Base Case forecast by calendar year is approximately 60 percent higher than AESC 2013.

Exhibit 5-32. Capacity Costs – AESC 2015 Base Case and AESC 2013

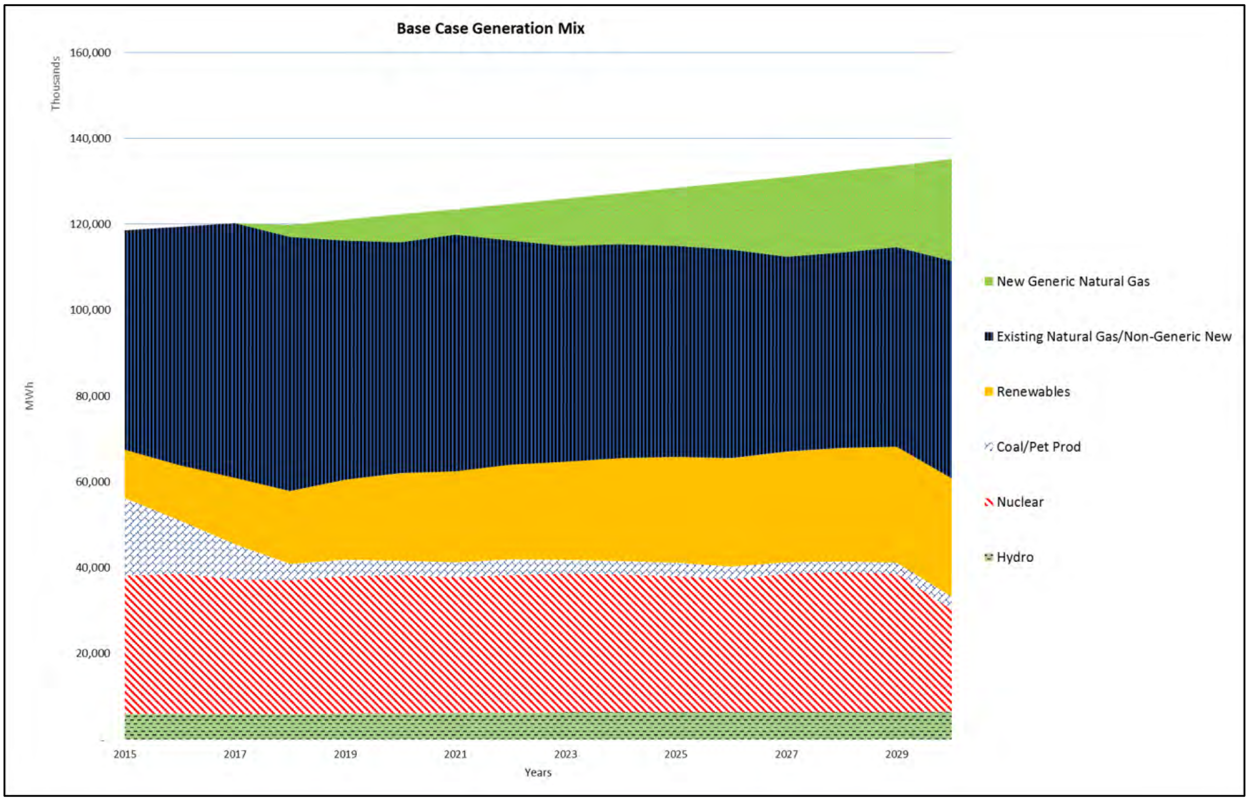
Power Year (June - May)	AESC 2013	AESC 2015 Base Case	Calendar Year	AESC 2013	AESC 2015 Base Case
	2015$/kW-month	2015$/kW-month		2015$/kW-year	2015$/kW-year
2015/16	$ 3.42	$ 3.38	2015	$40.99	$39.67
2016/17	$ 3.26	$ 3.15	2016	$36.89	$38.16
2017/18	$ 3.42	$ 14.19	2017	$40.99	$114.53
2018/19	$ 3.85	$ 12.96	2018	$46.20	$132.93
2019/20	$ 4.25	$ 11.29	2019	$51.05	$123.29
2020/21	$ 7.86	$ 11.33	2020	$94.27	$135.75
2021/22	$ 9.56	$ 11.71	2021	$114.76	$138.60
2022/23	$ 9.56	$ 11.62	2022	$114.76	$139.90
2023/24	$ 9.56	$ 11.37	2023	$114.76	$137.73
2024/25	$ 9.56	$ 11.96	2024	$114.76	$140.57
2025/26	$ 9.56	$ 11.96	2025	$114.76	$143.50
2026/27	$ 9.56	$ 12.04	2026	$114.76	$144.08
2027/28	$ 9.56	$ 11.79	2027	$114.76	$142.75
2028/29	$ 9.56	$ 12.46	2028	$114.76	$146.18
2029/30	$ 9.56	$ 12.79	2029	$114.76	$151.86
			2030	$114.76	$153.53
15 yr Levelized					
15/ 16 to 29/30	$7.95	$11.74	**2016 -2030**	$100.74	$142.08
AESC 2015 vs AESC 2013		48%			41%

The AESC 2015 capacity prices are actuals for the Rest of Pool (ROP) for power years 2015/16 through 2017/18 and are projections for 2018/19 through 2029/30. Note that in 2016/17capacity prices in the NEMA-Boston zone were different from the Rest of Pool. In addition, these projections do not reflect the FCA 9 results for 2018/19, which were not available at the time the AESC 2015 projections were made. However, the avoided electricity costs by zone provided in Appendix B reflect the actual results by zone for FCA 8 and FCA 9.

5.5.2 Forecast of Energy and Energy Prices

The projected level and mix of generation in the Base Case is presented in Exhibit 5-33. Generation from nuclear remains flat until year 2029 and declines in 2030 assuming retirement of Seabrook in March of that year, and coal generation declines substantially as most units are retired. Generation from natural gas is the dominant resource, and renewable generation increases over time in compliance with RPS requirements. Generation mix shown does not add up to the total energy demand because it does not account for the interchange with neighboring systems and for net pumping of energy by pumped storage generators.

Exhibit 5-33. Base Case Generation Mix



Forecast of Wholesale Electric Energy Prices

For AESC 2015, we present streams of energy values for all of New England in the form of the hub price. This is separately presented for four periods—summer on-peak, summer off-peak, winter on-peak, winter off-peak.[156]

The hub price representing the ISO-NE Control Area is located in central Massachusetts, and the WCMA zone in the pCA model is used as the proxy for that location. Exhibit 5-34 presents monthly, on-peak and off-peak energy prices as produced by the model through 2030 for Central Massachusetts. The higher

[156] Summer is defined as the four months June through September, with winter the other eight months, as done in AESC 2013. By combining the true winter season within spring and fall, the effects of high prices during the coldest months are moderated. AESC 2013 defined "on-peak" hours as 7 am – 11 pm.

winter on-peak price in the initial years represents the current high winter natural gas basis prices, which moderate as more pipeline capacity is added.

Exhibit 5-34. AESC 2015 Base Case Wholesale Energy Price Forecast for Central Massachusetts

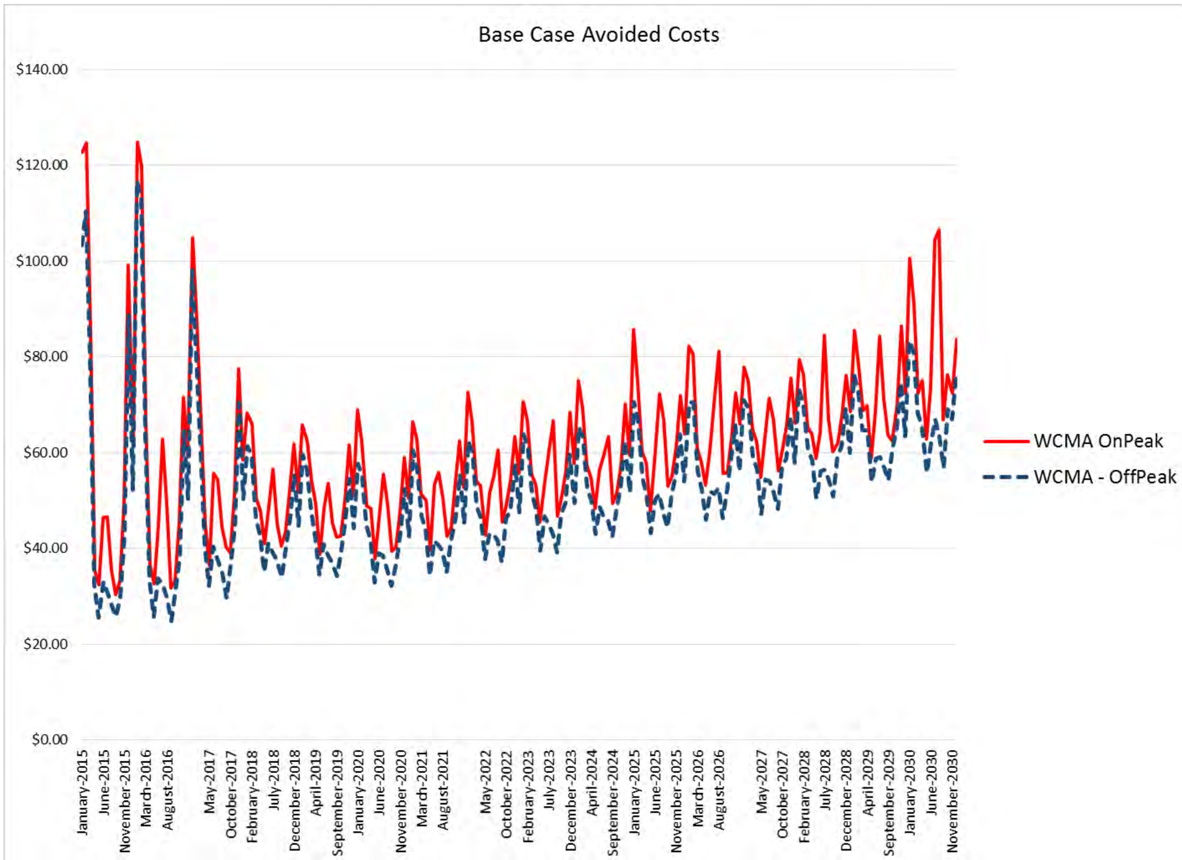


Exhibit 5-35 provides annual summaries by year, season and Peak vs. Off-Peak time periods.

Exhibit 5-35. AESC 2015 Base Case Wholesale Energy Price Forecast for Central Massachusetts (2015$/MWh)

	Summer			Winter		
Year	Off-Peak	OnPeak	AllHours	Off-Peak	OnPeak	AllHours
2015	$30.43	$39.83	$34.99	$64.89	$73.33	$68.90
2016	$30.79	$47.42	$38.67	$61.76	$66.69	$64.10
2017	$36.46	$48.93	$42.36	$59.05	$63.80	$61.30
2018	$39.30	$47.88	$43.34	$49.33	$54.02	$51.58
2019	$38.86	$47.60	$43.01	$48.61	$53.30	$50.86
2020	$37.33	$47.86	$42.38	$46.87	$51.95	$49.31
2021	$40.25	$50.69	$45.26	$49.19	$54.04	$51.50
2022	$42.36	$53.34	$47.65	$51.95	$57.22	$54.43
2023	$44.90	$57.13	$50.74	$53.67	$58.56	$55.98
2024	$47.14	$57.28	$51.95	$55.85	$60.69	$58.19
2025	$49.23	$62.74	$55.65	$57.79	$64.58	$61.07
2026	$51.50	$66.79	$58.74	$60.06	$66.02	$62.89
2027	$53.22	$64.54	$58.63	$61.89	$67.28	$64.46
2028	$55.81	$69.01	$61.99	$64.06	$68.86	$66.32
2029	$58.48	$72.05	$64.90	$68.02	$72.70	$70.24
2030	$63.40	$87.96	$75.13	$71.22	$79.63	$75.30

In sum, these benchmarking results demonstrate that the pCA modeling environment and supporting datasets provide a reliable tool for developing electric energy price projections.

5.5.3 Comparison to AESC 2013 Base Case

The following section summarizes differences between the AESC 2015 Base case and the AESC 2013 Base Case. Exhibit 5-36 compares the two AESC forecasts on a levelized basis. On a levelized annual basis, the AESC 2013 Base Case wholesale energy prices for WCMA are 7%below those of AESC 2013.[157]

The AESC 2015 Base Case levelized values are lower than the AESC 2013 Base Case in winter and summer periods, ranging from 3.3% to 15.6%. The lower summer prices reflect overall lower natural gas prices. The difference in winter prices is relatively small.

[157] Levelized values have been calculated for AESC 2015 using a discount rate of 2.43 percent, and for AESC 2013 using a discount rate of 1.36 percent.

Exhibit 5-36. 15-Year Base Case Levelized Cost Comparison for Central Massachusetts (2015$/MWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual All-Hours Energy
AESC 2015 (2016-2030)	$62.10	$56.82	$57.68	$45.04	$56.58
AESC 2013 (2014 - 2028)	$66.64	$58.78	$66.03	$53.33	$61.95
% Difference	-6.8%	-3.3%	-12.6%	-15.6%	-8.7%

Notes:
All prices expressed in 2015$ per MWh.
Discount Rate 1.36% for AESC 2013, 2.43% for AESC 2015

5.5.4 Forecast of Electric Energy Prices by State

TCR developed monthly on-peak, off-peak and all-hours prices for eight SMD zones, five zones represent individual states and Massachusetts is represented by three zones – NEMA-Boston, SEMA and WCMA. On average, our results show very little price separation between these zones and very little transmission congestion in the future.

5.6 Avoided Cost of Compliance with RPS

The Base Case electric energy and capacity market prices presented in Section 5.5 reflect the projected impact of energy and capacity from renewable resources developed to comply with RPS requirements. This Section describes those resource additions and provides our projection of renewable energy certificates (REC) prices.

5.6.1 Resource Additions to Meet Renewable Portfolio Standards

AESC 2015 assumes load-serving entities (LSEs) will comply fully with RPS requirements, either through acquisition of GIS Certificates/RECs or through making Alternative Compliance Payments (ACP). The rate at which the ACP is set—which varies across the New England states and RPS subcategories[158]—will, however, influence the manner in which compliance is achieved. All else equal (e.g., in the absence of bilateral contracts or asset ownership that would dictate otherwise), states with lower ACPs (Connecticut and New Hampshire) will tend to see a shift from REC to ACP compliance during periods of shortage, while RECs flow to markets where the ACP and REC prices are higher.

The gross requirements for each RPS class were derived by multiplying the load of obligated entities (those retail LSEs subject to RPS requirements, often with exemptions for public power) by the applicable annual class-specific RPS percentage target. The exemptions, which differ somewhat from

[158] State RPS requirements are differentiated by resource type, size/application, or age, resulting in multiple subcategories—also referred to as tiers or classes—within each state's RPS.

those used in AESC 2013, are presented in Exhibit 5-37, along with notes on their derivation. Projected voluntary demand for new resources is added to Class 1 requirements.

Exhibit 5-37. Exemptions from RPS Obligations

State	Percentage of Load Exempt from RPS Requirements	Methodology
CT	6.9%	Determined by comparing 2011 compliance data to ISO-NE real-time load data
MA	17.3%	Mass. DOER forecasts RPS obligated load for 2014 and beyond as 2013 obligated load escalated by ISO-NE CELT MA growth rate.
ME	2.2%	For portion of ME in ISO-NE only. Comparison of 2012 compliance data with ISO-NE real-time load data, using 2010 MPUC load data to determine exempt company load; added exemption for Pine Tree Development Zone.
NH	1.7%	Ratio of EIA municipal load from 2010 EIA-861 to total of that load plus RPS-obligated load from compliance report.
RI	1.2%	Determined by comparing 2012 compliance data to ISO-NE real-time load data

Analysis based on data from the following sources:

CT: "Annual Review Of Connecticut Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in the Year 2011," CT PURA Docket No. 12-09-02, June 4, 2014; ISO-NE real time load data for 2011 available at http://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/zone-info.

MA: "Massachusetts RPS & APS Annual Compliance Report for 2013," MA DOER, December 17, 2014; ISO-NE CELT forecast data available at http://www.iso-ne.com/static-assets/documents/trans/celt/fsct_detail/2014/isone_fcst_data_2014.xls

ME: "Annual Report on New Renewable Resource Portfolio Requirement Report for 2012 Activity," Presented to the Joint Standing Committee on Energy, Utilities and Technology March 31, 2014, Maine PUC; ISO-NE real time load data for 2012 available at http://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/zone-info; Maine PUC Electricity Statistics for 2010, available at http://www.maine.gov/mpuc/electricity/delivery_rates.shtml.

NH: "2011 Renewable Energy Portfolio Standard Review," Report of the New Hampshire Public Utilities Commission To the New Hampshire General Court, November 1, 2011; US EIA (2010), Form EIA-861, available at http://www.eia.gov/electricity/data/eia861/index.html.

RI: "Rhode Island Renewable Energy Standard (RES), Annual RES Compliance Report For Compliance Year 2012," Revised 3/25/14, Rhode Island Public Utilities Commission; ISO-NE real time load data for 2012 available at http://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/zone-info.

The RPS percentage requirements by class and year are listed in Appendix F. The load by state is the AESC 2015 Base Case load forecast (i.e., the gross load forecast assuming no new energy efficiency), as detailed in section 5.3.

The net demand for incremental renewable generation within New England is derived by subtracting from the gross demand:

a) Existing eligible generation already operating

b) Known near-term renewable additions

c) ISO New England's most recent long-term forecast of photovoltaic installations (largely distributed generation), which we extended from 2023 to 2030

d) RPS imports

An estimate of RPS-eligible imports over existing tie lines beyond current certified levels is phased in toward a maximum import, consistent with tie line capacity, competing uses of the lines and appropriate capacity factors of imported resources, the historical trend in RPS-eligible imports, and uncertainties in those factors.

Projected PV generation, based on ISO New England's PV forecast, is netted from demand because PV development is largely driven by policies other than the Class 1 RPS requirements.[159] The majority of PV development is projected to occur in Massachusetts. In AESC 2013, it was assumed that Governor Patrick's April 2013 announcement targeting 1,600 MWdc of solar installed by 2020 increased the MA Solar Carve Out by an incremental 800 MW, for a total Solar Carve-Out obligation of 1,200 MW by 2020. In April 2014, DOER launched the SREC-II program to continue the growth of solar market to meet Governor's 1,600 MWdc by 2020, and has continued to evolve its various incentives to encourage solar development. As of the end of 2014, there were approximately 700 MWdc installed in the state, approximately 280 MW of which was installed in 2014.[160]

In the near term (from 2015 to 2019), we assume that the aggregate net demand for new RPS supply will be met by a mix of renewable resources consistent with: (1) RPS-eligible resources in the New

[159] "2014 Interim Forecast of Solar Photovoltaic (PV) Resources," May 1, 2014, and "PV Energy Forecast Update," September 15, 2014. Presentations to the ISO-NE Distributed Generation Forecast Working Group. The PV forecast includes detailed estimates of installations in each state, developed in conjunction with those states. The projected new entry is primarily policy-forced, but includes a post-policy component; both components embody explicit realization rates that vary over the period.

[160] Analysis based on data from the following sources: MA DOER, "RPS Solar Carve-Out II Qualified Renewable Generation Units," updated February 15, 2015; MA Office of Energy and Environmental Affairs (MA EEA), "Current Status of the Solar Carve-Out II Program," accessed February 22, 2015, available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out-2/current-statis-solar-carve-out-ii.html; MA EEA, "Current Status of the Solar Carve-Out Program," accessed February 22, 2015, available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/current-status-of-the-rps-solar-carve-out-program.html; Massachusetts 225 CMR 14.00: RENEWABLE ENERGY PORTFOLIO STANDARD - CLASS I.

England administered systems, plus (2) other expected RPS-eligible generation in the development pipeline, which has not entered the queue. This includes both large projects that have not yet filed for interconnection studies, and distributed wind, solar, biomass, small hydro and tidal, and CHP projects, which—due to their size—are not required to go through the large generator interconnection process. Due to the increasing expense of entering and maintaining a position in the interconnection queue, some proposed projects must delay this stage of the process until early site evaluation and permitting progress has been sufficient to attract substantial development capital.

Renewable generation in the ISO interconnection queue that is under construction is listed in Section 5.3.6. Additional proposed generation for which information has entered the public domain, as well as generic renewable supply of various types are added as a result of policies and incentives. This information is grouped by load area as an input to the pCA model.

For the longer term (generally after 2019), we estimate the quantity and types of renewables that will be developed using a supply-curve approach based on resource potential studies. In this approach, discussed further below, resource build decisions are simulated by selecting from a supply curve of potentially available resources based on the resources' REC premium required to attract financing, subject to their ability to qualify under each state's main tier eligibility criteria, given their characteristics. This approach identifies the incremental resources required to meet net incremental Class 1 demand in each year through 2030. The one exception to this approach is solar PV, which as noted above is based on ISO New England's PV forecast.

5.6.2 Impact of Policy Uncertainty on RPS Supply

In some cases, the development and interconnection processes are also delayed by regulatory uncertainty. Examples of such uncertainty are available in each state in today's market—making the regional RPS marketplace increasingly complex and challenging for developers and investors.

A significant example of uncertainty around RPS requirements has to do with resource development in Vermont, the one state in New England without an RPS substantiated by REC retirement. In 2014, Vermont enacted legislation that significantly increased the amount of resources eligible for the state's net-metering program.[161] Formerly capped at 4% of a distribution utilities' load, the quantity of renewable resources eligible for net metering increased to 15%. The legislature has in the past defeated RPS bills and continued to support the resale of RECs associated with SPEED program resources into other New England RPS markets, although that appears to be changing, in part due to developments in other states. The Connecticut PURA was to rule in November 2014 in Docket No. 14-05-36, on whether and to what extent RECs associated with Vermont SPEED resources can be counted for compliance in

[161] State of Vermont, *An Act Relating to Self-Generation and Net Metering*, H.702 (April 2, 2014), http://www.leg.state.vt.us/docs/2014/bills/Passed/H-702.pdf

Connecticut's RPS (or whether that would constitute impermissible double-counting). Other states, notably Massachusetts, are watching the outcome of the proceeding.

The Vermont legislature is currently considering a bill (H.40) to replace the SPEED program with a program called the Renewable Energy Standard and Energy Transformation Program (RESET).[162] As of this writing, the bill is making its way through committee. For the purposes of AESC 2015, we assume no RPS demand for Vermont and that only RECs associated with existing Vermont renewable resources (but not new ones) will be allowed to be counted against RPS obligations in other states, and only through 2016.

5.6.3 REC Prices and Avoided Cost of RPS Compliance

REC prices are, simplistically speaking, effectively the premiums by which the cost of renewable energy exceeds the revenues available to renewable resources through the energy and capacity markets, with the marginal premium setting the market REC price.

RPS targets for Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island are a percentage of retail load as defined by state-specific legislation and regulation, estimated for AESC 2015 using the provisions in effect as of December 2015. Energy-efficiency programs reduce the cost of compliance because RPS requirements are generally volumetric, in proportion to the total load (in MWh) that must be supplied.[163] Reduction in load due to DSM will reduce the RPS requirements of LSEs and therefore reduce the costs they seek to recover associated with complying with these requirements. The RPS compliance costs that retail customers avoid through reductions in energy usage are equal to the product of REC prices multiplied by the percentage of retail load that a supplier must meet using renewable energy under the RPS regulations.

The following exhibit summarizes the change in Avoided RPS costs between AESC 2013 and AESC 2015. As detailed below, these avoided RPS costs represent a significant increase over the corresponding values in AESC 2013, due primarily to two factors. First, because AESC 2015 Base Case electric energy prices (and generator revenues) are considerably lower than those of AESC 2013, the REC premium for a given resource must be correspondingly higher to make up the shortfall below its levelized cost. The second factor is methodology. AESC 2013 used all-hours average prices to estimate renewable resources' revenues, which would tend to overestimate revenues—and therefore underestimate REC premium—for onshore wind resources, whose output is more heavily weighted toward off-peak / lower-

[162] "New renewable standard would revolutionize energy use in Vermont," J. Herrick, vermontbiz.org, accessed February 28, 2015. Available at: http://www.vermontbiz.com/news/february/new-renewable-standard-would-revolutionize-energy-use-vermont. A draft of the bill can be found at http://legislature.vermont.gov/assets/Documents/2016/WorkGroups/House Natural Resources/Bills/H.40/Draft, Summaries and Amendments/H.40~Aaron Adler~Draft No. 3.1 %282-50pm%29, 2-13-2015~2-17-2015.pdf

[163] Exceptions in New England include solar carve-outs, for which compliance targets are fixed MW quantities.

cost hours. By contrast, AESC 2015 used hourly prices and hourly production for each of the resources in the supply curve.

Exhibit 5-38. Comparison of Avoided RPS Costs

Comparison of Avoided RPS Costs $/MWh of Load Levelized Price Impact 2016 - 2030	CT	ME	MA	NH	RI	VT
AESC 2013 (2013$)	$4.62	$1.82	$6.25	$5.05	$3.45	$0.00
AESC 2013 (2015$)	$4.78	$1.88	$6.48	$5.23	$3.57	$0.00
AESC 2015 (2015$)	**$8.22**	**$0.51**	**$8.81**	**$8.67**	**$5.18**	$0.00
Percent Difference	72%	-73%	36%	66%	45%	-

Notes
Conversion from 2013$ to 2015$: 1.035
AESC 2013 levelization period (2014-2028) using a 1.36 percent discount rate.

Methodology

The method generally used in AESC 2015 to forecast REC prices, similar to that used in AESC 2013, varies by time period, as follows:

- **2015-2016**: Forecast REC prices are based on historical average broker quotations or bid-ask spreads for short-term forward transactions as of February 2015.
- **2017-2019:** Prices are interpolated by scrutinizing the expected balance between RPS-eligible supply and RPS demand.
- **2020 onward**: REC prices reflect the forecasted cost of new entry, modeled as described herein.

Estimating New or Incremental Renewable Additions and the Cost of New Entry

As with AESC 2013, the AESC 2015 analysis assumes that in the long run, the price of renewable energy certificates (and therefore the unit cost of RPS compliance) will be determined by the cost of new entry of the marginal renewable energy unit, relative to energy and capacity market revenues.

To estimate the REC premium, we forecast REC prices for each RPS subcategory, by state and by year, using a renewable resource expansion model that builds the least-cost set of resources needed to satisfy the RPS requirements net of existing resources. The "cost" of each renewable resource in this sense is the premium it needs above the energy and capacity market revenues it would receive, expressed as revenues per unit of energy generated, to equal its levelized cost of energy.

The model captures the various subcategory-specific nuances of the RPS requirements, including the degree to which rules limit resource eligibility based on characteristics and location, limitations on banking and borrowing, and ACPs that change over time.[164] The model also constrains the amount of a given resource that can be built in a given year in a given location to an estimate of technical potential. This is a different approach than AESC 2013, which calculated the market revenues of a renewable resource based on the all-hours average forecast LMP, the resource's capacity factor and forecast capacity prices. AESC 2015 calculates the annual market revenues of a renewable resource for each year based on the location of the resource, the forecast output of the resource in each hour, the AESC forecast of hourly energy prices for that location in that year and the AESC forecast of capacity prices for that location in that year. Revenues past 2030 for post-2020 installations are assumed to stay at the level of 2030 revenues in real terms.

AESC 2015 obtained or derived levelized costs and technical potential data for each resource type from various publicly available resource potential studies and economic analysis.[165] The estimated levelized costs are based on several key assumptions, including projections of capital costs, capital structure, debt terms, required minimum equity returns, and depreciation. Those assumptions are specific to the resource type and size and in some cases cover a range to account for a diversity of arrangements. The assumptions also include fixed and variable operations and maintenance costs, transmission and interconnection costs (as a function of voltage and distance from transmission), and wind integration costs.

As in AESC 2013, our analysis assumes there will be adequate transmission to accommodate the additional generation from these new renewable resources, and that the costs of any needed transmission upgrades will be socialized. Estimating the extent to which existing transmission facilities would require major upgrades (to integrate renewables or for any other reason) was beyond the scope

[164] In the event that an LSE purchases RECs in excess of its current year RPS obligation, states generally allow LSEs to save and count that quantity of compliance against either of the following two compliance years, subject to limitations. This compliance flexibility mechanism is referred to as banking. LSEs are also allowed to meet prior-year deficiencies with current year RECs (again, subject to limitations)—a provision sometimes called "borrowing." LSEs may only bank compliance within a single state, and may not transfer banked compliance credit to other entities.

[165] These assumptions are based on technology data compiled by Longwood Energy Group from a range of publicly available studies and interviews with industry participants. Public studies include: *Renewable Resource Supply Curve Report*, NESCOE, January 2012, *New England Wind Supply Curve*, Sustainable Energy Advantage, November 2011, *Lazard's Levelized Cost of Energy Analysis*—Version 8.0, Lazard, September 2014, *Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects*, R. Wiser et al., NREL and LBNL, February 2012, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014*, EIA, April 2014, *Levelized Costs of Electricity from CHP and PV*, Program Record 14003, T. Nguyen et al., US DOE, March 2014, and *Energy Efficiency and Renewable Energy Potential Study of New York State*, Final Report, Report Number 14-19, NYSERDA, April 2014. Data from these and other sources served as inputs to our own analysis to adjust and control for various parameters including vintage, cost trends, inflation, financing, penetration, geographic location, plant size and capacity factor.

of work for AESC 2015. Hence we do not provide the costs of any such upgrades or include them in our estimates of avoided costs.

AESC 2015 differentiates the levelized costs of resources by type, project size, and geographic location. Each of the resource blocks making up the potential supply curve are characterized by total nameplate capacity, hourly production profile, levelized cost, and operation applicable to projects coming online in each year. The potential supply curve consists of land-based wind, biomass, hydro, landfill gas, and offshore wind.

The Federal Production Tax Credit (PTC), renewed in December 2014, is assumed not to be extended again, such that only resources beginning construction before the end of 2014 are eligible. The Investment Tax Credit (ITC) is assumed to expire after 2016.

Unless the revenue from REC prices can make up the required REC premium, a project is unlikely to be developed, and in our simulation it will not be built. The highest REC premium of any resource built in a given subcategory, i.e., the marginal price, will set the REC price. Our projections assume that Class 1 REC prices for new renewables will not fall below $2/MWh—the estimated transaction cost associated with selling renewable resources into the wholesale energy market—except in the presence of an administratively set floor price. This estimate is consistent with effective market floor prices observed in various markets for renewable resources.

To project Maine Class 1 REC prices, we used an approach different from that of the other states, because Maine has put in place eligibility criteria that depart considerably from regional Class 1 norms, resulting in idiosyncratic market behavior. Under the Maine rules, compliance can be achieved largely with refurbished biomass generation that is ineligible in other states. The potential supply of eligible refurbished biomass resources in and outside Maine is not likely to be constrained in the time horizon of this analysis, given the modest increase in the Base Case Maine RPS obligation over the period. Beyond 2016, we estimated Maine Class 1 REC prices as the greater of (1) the difference between (a) an imputed levelized cost of energy based on 2015 REC prices and simulated biomass revenues and (b) simulated revenues going forward, and (2) the $2/MWh assumed floor described above.

Existing solar facilities across New England are eligible for NH Class II. As such, this market is expected to remain in balance and settle marginally above the MA Class I REC price for the remainder of the study period. As in AESC 2013, New Hampshire Class II REC prices are estimated at the lesser of (1) 90% of the ACP rate and (2) 105% of the Massachusetts/Maine/Rhode Island Class 1 ACP.

For RPS tiers for which we are not projecting prices using simulation, and for which no liquid forward market exists, we assume prices to stay, in real terms, at the level of broker-derived prices across the time horizon. The exception to this approach is for RPS classes focused on existing supply but for which such existing supply has not been certified by the applicable RPS authority in a quantity sufficient to meet demand. Near-term REC prices for such classes are estimated based on current broker quotes and the applicable ACP. REC prices are assumed to trend toward values which reflect a market in equilibrium or modest surplus over time, as existing generators become certified and participate in the program.

Exhibit 5-39 lists near-term REC market prices.

Exhibit 5-39. REC and APS Prices for 2015 and 2016 compliance years

		2014 REC Prices Q3&Q4 2014 Average (2015$/MWh)	2015 REC Prices Feb 2015 (2015$/MWh)	2016 REC Prices Feb 2015 (2015$/MWh)
CT	Class I	$53.66	$53.10	$49.96
	Class II	$0.55	$2.25	$2.46
	Class III	$24.20	$27.25	$26.30
MA	Class I	$55.20	$57.56	$56.34
	Class II – renewable		$26.50	
	Class II – WTE	$9.29	$9.44	
	APS	$20.95	$21.00	
ME	Class I	$2.35	$4.38	$5.41
	Class II		$0.30	
NH	Class I	$53.98	$52.50	$50.02
	Class II – Solar	$51.08		
	Class III			
	Class IV	$25.85		
RI	New	$50.65	$53.50	$49.16
	Existing	$0.80		

Source: Data from Intercontinental Exchange, SNL, and confidential REC brokers' quotations compiled by Longwood Energy Group. Prices for some products/years were not available.

We use the terms "Class 1" or "main tier" generally to refer to new or incremental renewable resources that qualify as Class I in Connecticut, Massachusetts, New Hampshire, Maine, and as "New" in Rhode Island. Class 1 REC prices will be driven both by the costs of renewable resources eligible in each state and by the quantity of state-specific supply compared to state-specific demand. Because RPS eligibility criteria differ by state, REC prices are differentiated by state and reflect state-specific expectations with respect to generator certification.

Massachusetts is unique in its treatment of the solar carve-out portion of its Class 1 obligation. While the carve-out itself is not unique, Massachusetts establishes an annual MWh obligation, which is then allocated among the obligated LSEs. In aggregate, this solar target is converted into a percentage of state load and is removed from the Class 1 percentage target for that year—thereby reducing the Class 1 RPS compliance obligation avoidable through energy efficiency activities. Because the solar carve-out represents an LSE obligation to procure a fixed quantity (MWh) of Solar RECs (SRECs) each year, we therefore treat it as not avoidable through energy efficiency measures that reduce all other RPS obligations.

Connecticut's current eligibility definitions also allow for certain biomass supply to be uniquely eligible in Connecticut, but its RPS targets have increased at a pace such that this supply is now sub-marginal.

Secondary tiers

While Class I RPS requirements generally spur the development of new renewable resources, Class II, III, and IV requirements are generally designed as "maintenance tiers," with the exception of special categories for new thermal and CHP resources. The maintenance tier programs are intended to provide just enough financial incentive to keep the existing fleet of renewable resources in reliable operation. Due to their maintenance orientation, Class II, III and IV percentage targets are generally held constant, with annual obligations varying only based on changes in the demand forecast.

CT Class II, MA Class II-WTE (waste to energy), ME Class II, and RI "Existing" REC markets have been in surplus. Therefore, REC prices in these markets are expected to remain relatively constant at levels just above the transaction cost. The MA Class II-RE (non-waste) market (which has overlapping eligibility with CT Class I), has an obligation that rises annually until 2016, whereas the Class II-WTE obligation remains fixed.

While there is theoretically ample supply to meet MA Class II and New Hampshire Class III, fewer generators than expected have undertaken the steps necessary to comply with the eligibility criteria and become certified. As a result, those two markets have been in shortage. As a result, steps have been taken in both markets to address the imbalance. Retroactive regulatory revisions to MA Class II were announced in February 2014 and completed in June in part to bring the market into a balance more consistent with a policy targeting existing resources, with less reliance on the ACP mechanism. The changes have left the market much less short of demand in 2013 than it was in 2012.[166] The market is still short, however, with obligated entities paying ACPs to cover the shortfall, albeit few of them; the current REC price is essentially unchanged from the then-current price in AESC 2013. For these reasons we continue the assumption that long-run MA Class II REC prices to be the lesser of CT Class I REC prices and 50 percent of the MA Class II ACP rate.

The NH Class III (existing biomass/methane) and NH Class IV (existing small hydro) markets[167] have overlapping eligibility with the higher-priced CT Class I, and have historically competed with that program for resources, resulting in compliance that has relied heavily on ACP payments. The New Hampshire PUC in 2014 solicited comments regarding adjusting RPS requirements for 2013-2015, in particular for Class III.[168] The order reduced only the Class III requirement for 2013 (to 0.5 percent), it is

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[166] Massachusetts RPS & APS Annual Compliance Report for 2013, MA DOER, December 17, 2014.

[167] Several Class III biomass and Class IV hydroelectric facilities have been certified in both NH III or IV, respectively, and CT Class I.

[168] Order Reducing Class III Requirements for 2013 to 0.5% of Retail Sales. Order No. 25,674 in Docket No. DE 14-104, ELECTRIC RENEWABLE PORTFOLIO STANDARD, Adjustments to Renewable Portfolio Class Requirements, June 3, 2014.

slated to rise to 8% in 2015, and the PUC may make further changes after continuing to monitor the markets.

Responding to a recommendation by the Connecticut Department Of Energy and Environmental Protection (DEEP) to reduce reliance on out of state biomass and landfill gas to meet Connecticut's Class 1 targets, the legislature in 2013 passed a law requiring the Commissioner of Environmental Protection to "…establish a schedule to commence on January 1, 2015, for assigning a gradually reduced renewable energy credit value to all biomass or landfill methane gas facilities that qualify as a Class I renewable energy source…"[169] Such a change could enhance New Hampshire's ability to meet its Class III targets, although the law is rather vague and it's unclear what shape the changes will take.[170] DEEP is now recommending delaying a reduction in biomass REC values until 2018.[171]

In the long-run, NH-III and NH-IV REC prices are assumed to be the lesser of CT Class I and 90 percent of their respective ACP rates.

The MA Alternative Energy Portfolio Standard (APS), which provides incentives for investments in efficient thermal or storage resources such as CHP (including natural gas fuel cells), flywheel storage, geothermal heat pumps, and waste heat recovery, is in significant shortage. Both the APS and the similar CT Class III are less fungible than other REC markets because of the need to use any thermal energy produced in-state. The CT Class III market, like the APS, has had difficulty meeting its goals, given insufficient CHP development.[172] The CT Class III goal remains fixed at 4 percent, and Connecticut ACPs are fixed in nominal terms, which mean they decline in real terms rather than rise with inflation as those of most other states. By contrast, the APS goal continues to increase, and its ACP is indexed for inflation. REC prices for MA APS are forecasted at 90 percent of the ACP rate; CT Class III prices are expected to remain at about 86 percent of ACP (therefore declining in real terms) over the period.

Existing solar facilities across New England are eligible for NH Class II. As such, this market is expected to remain in balance at about 90 to 95 percent of ACP, as solar resources age out of solar carve outs and competing Class 1 prices drop.

Class I requirements will outpace the other classes on a GWh basis over time. This phenomenon is shown in Exhibit 5-40, which summarizes New England's total renewable energy requirements by year,

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169 Subsection (h) to Connecticut General Statue section 16-245a, effective June 5, 2013.

170 "The Gradually Reduced Credit for Biomass Energy in Connecticut: A Vague But Still Constitutional Standard," Brian M. Gibbons, Connecticut Law Review, V.47, December 2014.

171 2014 Integrated Resource Plan For Connecticut, Draft For Public Comment, Prepared by The Connecticut Department Of Energy and Environmental Protection, December 11, 2014. "The Department proposes to monitor RPS compliance and the capacity market and, in the next IRP, consider establishing a schedule for reduced REC value beginning in 2018 subject to the comments and feedback from stakeholders."

172 Beginning in 2014, ratepayer-funded energy efficiency resources were no longer eligible in Connecticut Class III formerly included energy conservation and load management. Prior to that time, prices remained near the $10 administratively set floor. Since the phase-out of energy efficiency resources, prices have been more reflective of the gap between demand and supply.

based on the RPS percentage targets by state and the AESC 2015 Base Case / gross load forecast, as discussed in Chapter 5. Exhibit 5-41 distinguishes between the quantities of Class I renewables that are required and the *aggregate* quantity of all other classes of renewables combined.

Exhibit 5-40. Summary of New England RPS Demand

New England Annual RPS Demand (GWh)			
Year	**Class 1**	**Other Classes**	**Total**
2015	10,931	11,387	22,318
2016	12,325	11,872	24,197
2017	13,718	12,051	25,769
2018	14,882	12,145	27,027
2019	16,542	12,378	28,920
2020	17,474	12,613	30,088
2021	18,265	12,853	31,118
2022	19,069	13,097	32,166
2023	19,887	13,343	33,230
2024	20,721	13,594	34,315
2025	21,570	13,848	35,418
2026	22,315	14,106	36,421
2027	23,072	14,368	37,440
2028	23,842	14,634	38,476
2029	24,626	14,903	39,529
2030	25,422	15,177	40,599

Notes:

Based on Base Case load forecast and RPS targets as of 12/31/2014, with exemptions for non-obligated entities, and Maine NMISA demand excluded. Class I includes Solar Carve Outs. Does not include voluntary demand.

The major sources of the renewable supply forecast used to meet the RPS requirements by year are shown in Exhibit 5-41. These sources include wind (onshore and offshore), biomass, and hydro.

Exhibit 5-41. Cumulative Supply of Class 1 Renewable Energy Resources in New England, by Fuel Type

	Class 1 Renewable Energy Supply, by Fuel Type (GWh)						
Year	**Wind**	**Biomass**	**Solar**	**Hydro**	**LFG**	**CHP**	**Total**
	a	b	c	d	e	f	g = sum a to f
2015	2,324	3,363	1,479	410	1,204	1,659	**10,440**
2016	2,983	3,463	1,721	637	1,204	1,765	**11,773**
2017	4,816	3,548	1,817	740	1,204	1,839	**13,963**
2018	5,243	3,841	2,009	842	1,204	1,839	**14,977**
2019	5,521	3,953	2,181	923	1,344	1,948	**15,870**
2020	6,147	4,064	2,337	1,005	1,344	2,077	**16,973**
2021	6,619	4,149	2,448	1,026	1,484	2,208	**17,934**
2022	6,849	4,212	2,514	1,047	1,624	2,342	**18,589**
2023	7,215	4,275	2,580	1,048	1,694	2,465	**19,276**
2024	7,674	4,338	2,645	1,049	1,694	2,589	**19,989**
2025	8,155	4,401	2,710	1,050	1,694	2,716	**20,727**
2026	8,545	4,460	2,776	1,051	1,694	2,846	**21,371**
2027	8,958	4,520	2,841	1,051	1,694	2,977	**22,041**
2028	9,705	4,569	2,906	1,053	1,694	3,111	**23,038**
2029	10,499	4,598	2,971	1,054	1,694	3,248	**24,064**
2030	11,322	4,627	3,037	1,055	1,694	3,386	**25,122**

Includes existing and projected energy production by Class 1 renewables and CHP. Hydro includes tidal. CHP includes natural gas fuel cells. CHP listed in terms of GWhe, except for MA CHP, listed in terms of AEC GWh.

The expected distribution of Class 1 RPS supplies between ISO-NE and adjacent control areas is summarized in Exhibit 5-42. Supply is categorized as follows:

- Existing eligible generation already operating
- Known additions not yet operating
- Projected incremental renewable resources by fuel type
- Energy / RECs currently imported from RPS-eligible facilities located outside of ISO-NE
- Assumed incremental energy / RECs imported from outside of ISO-NE

Exhibit 5-42. Expected Distribution of New Renewable Energy between ISO-NE and Adjacent Control Areas

	Class 1 RPS Supply (GWh)						
	ISO-NE Supply		Imported Supply				
Year	Operating	Incremental	Current	Expected	**Total Supply**	**New Renewable Requirement (GWh)**	**New Renewable Energy Surplus (Shortage)**
	a	b	c	d	e = sum a to d	f	g = e-f
2015	7,882	1,600	1,662	-	11,144	11,046	99
2016	7,882	2,918	1,662	-	12,462	12,457	5
2017	7,181	4,944	1,662	83	13,870	13,870	0
2018	7,181	5,956	1,662	258	15,057	15,057	0
2019	7,181	6,684	1,662	546	16,072	16,743	(671)
2020	7,181	7,688	1,662	845	17,375	17,706	(330)
2021	7,181	8,545	1,662	1,144	18,531	18,531	0
2022	7,181	9,089	1,662	1,443	19,375	19,375	0
2023	7,181	9,654	1,662	1,742	20,239	20,239	0
2024	7,181	10,242	1,662	2,041	21,126	21,126	0
2025	7,181	10,853	1,662	2,340	22,036	22,035	0
2026	7,181	11,368	1,662	2,639	22,850	22,850	0
2027	7,181	11,906	1,662	2,938	23,687	23,687	0
2028	7,181	12,769	1,662	2,938	24,550	24,550	0
2029	7,181	13,659	1,662	2,938	25,440	25,439	0
2030	7,181	14,578	1,662	2,938	26,359	26,358	0

Notes:

RPS requirement is scaled to Base Case load. Requirement and supply quantities here reflect those of main tiers for new renewables, including solar carve-outs, plus voluntary demand. The Massachusetts APS and similar programs are not included here. Vermont supply is included only through 2016, resulting in a decrease in column (a) quantity thereafter. Much of the column (g) shortages shown for 2019-2020 could be offset by banked surpluses from 2014 (not shown) through 2016, parlayed forward by banking in each intervening year.

Exhibit 5-42 also compares total Class 1 RPS supply to total Class 1 RPS demand. The combination of operating supply, projects currently under development, imported supply and resource potential from the renewable energy supply curve analysis are expected to keep supply and demand in balance through 2030.

The eligibility details and target percentages for main tier and secondary tier resources are summarized in Appendix F.

5.6.4 Estimated Cost of Entry for New or Incremental Renewable Energy

Our general approach to estimating the cost of entry for new or incremental renewable supply is described above.

Beginning in 2020, regional REC prices are expected to converge as all states rely on new or incremental renewable resources to meet their RPS demands—with only modest price differentials between states based on eligibility, bank balances and utility-specific decisions to retire the RECs from long-term contracts in satisfaction of RPS obligations. Our projection of the cost of new entry for each state is summarized in Exhibit 5-43.

Exhibit 5-43. REC Premium for Market Entry

AESC 2015 Class 1 REC Premium (2015$/MWh)						
	CT	**ME**	**MA**	**NH**	**RI**	**VT**
2015	$53.10	$4.38	$57.56	$54.97	$53.50	$0.00
2016	$49.96	$5.41	$56.34	$52.50	$49.16	$0.00
2017	$47.62	$4.27	$52.40	$49.52	$47.02	$0.00
2018	$45.27	$5.99	$48.46	$46.54	$44.87	$0.00
2019	$42.92	$7.39	$44.52	$43.56	$42.72	$0.00
2020	$40.57	$8.04	$40.57	$40.57	$40.57	$0.00
2021	$36.75	$5.60	$50.50	$49.61	$48.78	$0.00
2022	$46.63	$2.39	$46.69	$46.69	$46.69	$0.00
2023	$43.94	$2.00	$43.62	$43.94	$43.39	$0.00
2024	$42.00	$2.00	$41.38	$41.38	$41.38	$0.00
2025	$38.74	$2.00	$38.74	$38.74	$38.74	$0.00
2026	$35.79	$2.00	$35.72	$35.72	$35.72	$0.00
2027	$32.86	$2.00	$32.86	$32.86	$32.86	$0.00
2028	$30.13	$2.00	$35.28	$30.13	$30.13	$0.00
2029	$32.66	$2.00	$32.66	$32.66	$32.66	$0.00
2030	$30.46	$2.00	$30.46	$30.46	$30.46	$0.00
2016-2030 levelized	**$40.32**	**$3.84**	**$42.74**	**$41.66**	**$40.93**	**$0.00**

These REC premium results reflect the RPS demands of the post-2018 Base Case load forecast. (The load in the BAU Case is lower and would have a commensurately lower RPS requirement). The REC premiums are highly dependent upon the forecast of wholesale electric energy market prices, including the underlying forecasts of natural gas and carbon allowance prices. A lower forecast of market energy prices would yield higher REC prices than shown, particularly in the long term. In most cases, project developers will need to be able to secure long-term contracts (or financial equivalents, such as synthetic PPAs), and attract financing based on the aforementioned natural gas, carbon, and resulting electricity price forecasts. This presents an important caveat to the projected REC prices, because such long-term electricity price forecasts (particularly to the extent that they are influenced by expected carbon regulation) are not easily taken to the bank.

In contrast to the long-term REC cost of entry, spot prices in the near term will be driven by supply and demand, but are also influenced by REC market dynamics and to a lesser extent to the expected cost of entry (through banking), as follows:

- Market shortage: Prices approach the cap or Alternative Compliance Payment
- Substantial market surplus, or even modest market surplus without banking: Prices crash to approximately $0.50 to $2/MWh, reflecting transaction and risk management costs
- Market surplus with banking: Prices tend towards the cost of entry, discounted by factors including the time-value of money, the amount of banking that has taken place, expectations of when the market will return to equilibrium, and other risk management factors

These Class 1 REC prices, with the exception of Maine, represent a significant increase over the corresponding values in AESC 2013. The increase is due primarily to two factors. First, because AESC 2015 Base Case electric energy prices (and generator revenues) are considerably lower than those of AESC 2013, the REC premium for a given resource must be correspondingly higher to make up the shortfall below its LCOE. Although capacity revenues are higher in AESC 2015 than in 2013, capacity payments don't comprise a large share of market revenues wind resources whose REC premiums set the clearing price for much of the period. Part of the increase is likely attributable to methodology. AESC 2013 used all-hours average LMPs to estimate renewable resources' revenues. By contrast, AESC 2015 used hourly LMPs and hourly production for each of the resources in the supply curve. Onshore wind resources tend to produce more during off-peak periods when prices are lower, so an all-hours average energy price may overestimate energy revenue, leading to an underestimate of the required REC premium. Finally, Class 1 RPS requirements, which on average increase over time, are in many cases higher for the 2015-2030 period than for the 2013-2028 period analyzed in AESC 2013.

In the AESC 2015 analysis, REC prices decline over the period—although not uniformly—as revenues increase and technology learning curves reduce LCOEs—countering the effect of moving further up the supply curve as less expensive resources are exhausted.

REC premiums hit the caps set in the model in only one instance—in Connecticut (2022).[173] This year corresponds to the tightest period of supply relative to net demand, and it is possible that more significant banking might have alleviated the shortfall. Unlike in all other states where ACPs are indexed to inflation (CPI) , Class 1 ACPs in Connecticut and New Hampshire decline in real terms over time, while demand increases.[174] As a result, during times when REC premiums are high, supply naturally flows to other states.

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[173] The caps were set at 90% of ACP in all states but Connecticut and New Hampshire, set at 97% of ACP.

[174] ACPs in Connecticut are fixed in nominal terms; Class I and II ACPs in New Hampshire escalate at only half of CPI, and thus also decrease in real terms.

As described above, Maine is an outlier with regard to Class 1 market prices, owing to its eligibility criteria significantly less constraining than those of other states. Compliance with Maine's Class 1 requirement is predominantly achieved using new or refurbished biomass resources that are ineligible in other states. As a result, the market there is somewhat oversupplied, with prices currently in the range of \$5 per MWh. Prices rise somewhat before falling to the assumed floor in 2023.[175]

Detailed projections of REC prices by state for Class I renewables are presented in Appendix F.

5.6.5 Calculating Avoided RPS Compliance Cost per MWh Reduction

The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices (e.g., the REC price) multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

Avoided RPS cost = REC price × RPS requirement as a percentage of load

We calculate the RPS compliance costs that retail customers in each state avoid through reductions in their energy usage in each year for each major applicable RPS tier as follows:

$$\frac{\sum_n P_n \times R_n}{1 - L}$$

Where:

n = the RPS class

P_n = projected price of RECs for RPS class n

R_n = RPS requirement, expressed as a percentage of energy load, for RPS class n, from Appendix F

L = the load-weighted average loss rate from ISO wholesale load accounts to retail meters

For example, in a year in which REC prices are \$30/MWh and the RPS percentage target is 10 percent, the avoided RPS cost to a retail customer would be \$30 × 10% = \$3/MWh. Detailed results from Appendix C are incorporated into the Appendix B Avoided Cost Worksheets by costing period.

For the purposes of calculating the avoided RPS cost associated with the MA Class 1 requirement, of which the MA Solar Carve-Out is a subset, we project the incremental capacity of SCO resources installed in each year and the energy generated during the first ten years after installation, and divide

175 A scenario in which Maine Class 1 prices fall even sooner is possible should Governor Paul LePage's proposal to lift the 100 MW cap on hydro resources be adopted. The Governor has pushed for this policy change four years in a row, but it has failed amid bipartisan opposition.

the cumulative energy generated by the RPS-eligible load to yield a load percentage for each year that is subtracted from the MA Class 1 requirement. The carve-out percentage increases to a maximum of 3.6% in 2020, and decreases to 0.1% by 2030.

The year-by-year RPS percentages for each RPS class are shown in Appendix F. The levelized RPS price impact for the 2016 to 2030 period, in 2015$ per MWh of load, is shown below.

Exhibit 5-44. Avoided RPS Cost by Class, Levelized Price Impact 2016 - 2030

	CT	ME	MA	NH	RI	VT
Class 1	$7.13	$0.41	$6.72	$4.90	$5.17	$0.00
All Other Classes	$1.08	$0.10	$2.09	$3.77	$0.02	$0.00
Total	$8.22	$0.51	$8.81	$8.67	$5.18	$0.00

The exhibit shows (with the exception of Maine) levelized avoided costs of 1.4 - 1.9 times those of AESC 2013, with the increase attributable primarily to higher REC premiums, and to a lesser extent, RPS requirements that increase with time.[176]

5.7 Assessment of Alternative Electric Energy Costing Periods

The Study Group asked the AESC 2015 project team to recommend alternative costing periods if an analysis of avoided cost results indicates that the alternative costing periods may more accurately and reasonably reflect seasonal and hourly variation of marginal energy costs than the existing on-peak and off-peak costing periods. In essence the goal is to determine whether more granular costing periods, referred to as "super on-peak" periods, may provide a more accurate value of reductions which occur primarily during that time period. This section describes our analyses and recommendations regarding super on-peak periods.

5.7.1 Analysis of alternative costing periods

AESC 2015 analyzed electric energy prices by hour in summer on-peak periods and in winter on-peak periods in four steps.

First it identified the months within each season during which on-peak period energy prices by hour were consistently the highest. That analysis indicated that on-peak period energy prices by hour in June,

176 AESC 2013 calculated 15-year levelized costs for 2014-2028, while the period 2016-2030 is used here. This has the effect of dropping the two years with the lowest RPS requirements (2014-2015) while adding two years with the highest (2028-2030).

July and August were consistently higher than September. Using a similar approach we identified three winter months for further assessment - December, January and February.

Second, it analyzed five data sets of hourly prices for the WCMA zone for each of those months, three sets of historical energy prices and two sets of projected energy prices. The historical data sets are from 2012, 2013 and 2014, the projected prices are from the Base Case for June 2019 through May 2020 and for June 2025 to May 2026. For each dataset we computed average prices for each on-peak hour in each of the three summer months and each of the three winter months. For example, for June 2012 we computed average hourly prices for each of the 16 on-peak hours, i.e. hours beginning at 07:00 and ending at 23:00.

Third, it analyzed energy prices by hour in blocks of four consecutive hours for several different possible blocks in order to identify candidate super on-peak periods by season. For winter months we analyzed the following 4 hour blocks: between hours beginning at 14:00 and ending at 18:00, 15:00 -19:00, 16:00 -20:00 and 17:00 -21:00. For summer months we analyzed the following 4 hour blocks: between hours beginning at 11:00 and ending at 15:00, 12:00 -16:0, 13:00 -17:00 and 14:00 -18:00.

Fourth, it ranked each different 4 hour block within each season according to the block's average price of energy by hour during each season. The block with the highest average price was ranked 1 and the block with the lowest average price was ranked 4. Exhibit 5-45 presents the ranking results.

Exhibit 5-45. Ranking of candidate super on-peak Periods for avoided energy costs

Winter Blocks	2012	2013	2014	2019/20	2025/26	Total of Ranks
14:00-18:00	4	3	4	4	3	18
15:00-19:00	3	2	3	3	2	13
16:00-20:00	**1**	**1**	**2**	**2**	**1**	**7**
17:00-21:00	2	4	1	1	4	12
Summer Blocks	**2012**	**2013**	**2014**	**2019/20**	**2025/26**	**Total of Ranks**
11:00-15:00	4	3	4	4	4	19
12:00-16:00	3	1	3	2	1	10
13:00-17:00	**1**	**2**	**1**	**1**	**2**	**7**
14:00-18:00	2	4	2	3	3	14

The summer block with the highest ranking begins at hour 13:00 and ends at 17:00. This block coincides with the summer Demand Resource Forecast Peak Hours defined by ISO-NE.[177] The winter block with the highest ranking begins at 16:00 and ends at 20:00 in the winter. This block encompasses the winter Demand Resource Forecast Peak Hours defined by ISO-NE as the two-hour block beginning at 17:00 and ending at 19:00 on non-holiday weekdays during the months of December and January.

[177] ISO-NE Tariff, Section I – General Terms and Conditions, Definition of Demand Resource Forecast Peak Hours.

Exhibit 5-46 presents the key statistics on the duration and prices during super-peak hours relative to the average on-peak period price for that season for each of the five datasets.

Exhibit 5-46. Ratio of average price in top ranked candidate super-peak to average price for season on-peak

	2012	2013	2014	2019/20	2025/26	Average
Winter						
HOURS						
Peak (Oct – May, 1)	2800	2800	2784	2784	2768	2787
Super-Peak (Dec – Feb, 16 thru 20)	256	260	264	260	260	260
Non-super Peak	2544	2540	2520	2524	2508	2527
Prices ($/MWh)						
Peak	$40.77	$71.25	$93.20	$52.81	$65.67	$64.74
Super-Peak	$51.14	$129.72	$165.97	$74.10	$91.02	$102.39
Non-super Peak	$39.73	$65.27	$85.58	$50.62	$63.04	$60.85
Price Ratios						
Super-Peak/Peak	1.25	1.82	1.78	1.40	1.39	1.58
Non super Peak / Peak	0.97	0.92	0.92	0.96	0.96	0.94
Summer						
HOURS						
Peak (June – Sept))	1376	1376	1392	1376	1392	1382
Super-Peak (June – August; 13:00 thru 17:00)	264	260	260	260	260	261
Non-super Peak	1112	1116	1132	1116	1132	1122
Prices ($/MWh)						
Peak	47.23	48.97	42.89	47.60	62.74	$49.89
Super-Peak	64.65	59.79	50.57	55.60	79.84	$62.09
Non-super Peak	43.09	46.45	41.13	45.74	58.81	$47.04
Price Ratios						
Super-Peak/Peak	1.37	1.22	1.18	1.17	1.27	1.24
Non super Peak/Peak	0.91	0.95	0.96	0.96	0.94	0.94

Notes

1. Peak period is weekday hours, 7 am to 11 pm.

Based on the results of this analysis, AESC 2015 recommends the following super on-peak periods for avoided electric energy costs. For summer months of June through August, weekdays only (excluding holidays defined by ISO-NE), four hour interval from hour beginning at 13:00 to hour ending at 17:00, EDT. For winter months of January, February and December, weekdays only (excluding holidays defined by ISO-NE), four hour interval from hour beginning at 16:00 to hour ending at 20:00, EST.

Chapter 6: Sensitivity Cases

AESC 2015 prepared two sensitivity analyses, a lower load case and a higher gas price case, to provide information on how major changes to key assumptions used in the Base Case may affect electric avoided costs. The two sensitivity cases are a BAU Case, which is the lower load case, and a High Gas Price Case.

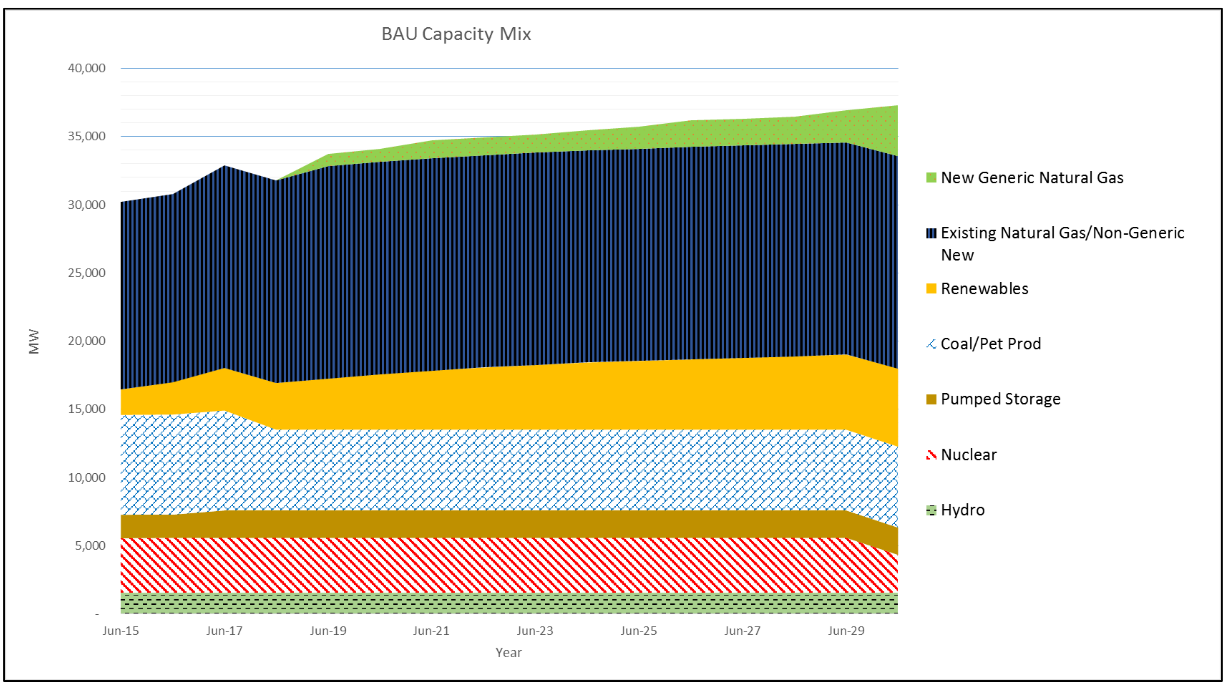
6.1 BAU Case

The BAU Case, also referred to as the market price sensitivity Case, represents a future under which ratepayer energy efficiency continues to be approved at the levels projected by ISO NE. The projected prices are a forecast of market prices under this future.

6.1.1 Forecast of Capacity and Capacity Prices

The projected level and mix of capacity in the BAU Case is presented in Exhibit 6-1. New capacity additions include renewable resources to comply with RPS requirements, as well as new natural gas generators added to meet energy and reserve margin requirements. A substantial portion of the existing oil (Pet Prod) and coal capacity is forecast to retire by 2025. Because of the relatively high price of oil compared to other fuels, these generating plants are rarely dispatched.

Exhibit 6-1. BAU Case Capacity by Technology vs. Peak Demand (MW)



6.1.2 Forecast of Energy and Energy Prices

Exhibit 6-2 illustrates the projected level and mix of generation in the BAU Case.

Generation from nuclear remains flat until year 2029 and declines in 2030 assuming retirement of Seabrook in March of that year, and coal generation declines substantially as most units are retired. Generation from natural gas is the dominant resource, and renewable generation increases over time in compliance with RPS requirements. However, given the absence of the load growth during the planning horizon under the BAU/ Case the projected growth of renewable generation is relatively mild. Generation mix shown does not add up to the total energy demand because it does not account for the interchange with neighboring systems and for net pumping of energy by pumped storage generators.

Exhibit 6-2. BAU Case Generation by Fuel (MWh)

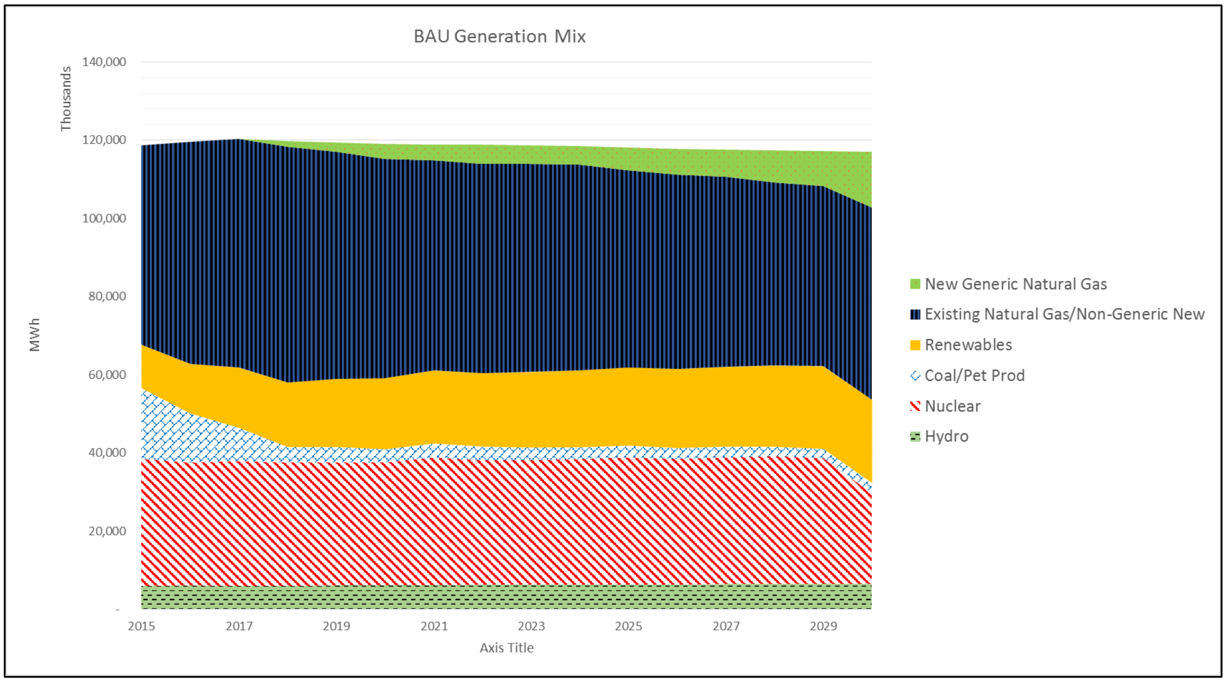


Exhibit 6-3 provides annual summaries by year, season and Peak vs. Off-Peak time periods.

Exhibit 6-3. Wholesale Energy Price Forecast for Central Massachusetts (2015$/MWh)

	Summer			Winter		
Year	Off-Peak	OnPeak	AllHours	Off-Peak	OnPeak	AllHours
2015	$30.50	$39.46	$34.84	$64.88	$73.24	$68.85
2016	$30.93	$47.01	$38.54	$61.75	$66.61	$64.05
2017	$36.63	$48.58	$42.29	$59.06	$63.74	$61.28
2018	$39.86	$48.03	$44.19	$49.04	$53.70	$51.35
2019	$38.85	$50.00	$44.16	$48.74	$53.29	$51.26
2020	$36.96	$46.27	$41.43	$47.72	$53.13	$50.29
2021	$40.25	$48.69	$44.29	$50.22	$54.13	$52.06
2022	$43.00	$58.05	$50.21	$52.15	$57.21	$54.54
2023	$45.13	$56.94	$50.76	$53.77	$58.72	$56.11
2024	$47.22	$58.45	$52.54	$56.02	$61.89	$58.85
2025	$49.27	$63.20	$55.86	$59.09	$65.95	$62.39
2026	$51.14	$63.23	$56.93	$60.30	$67.21	$63.58
2027	$53.54	$69.23	$61.02	$62.78	$68.17	$65.35
2028	$55.81	$68.11	$61.69	$64.48	$69.87	$67.04
2029	$58.36	$71.54	$64.61	$67.50	$74.82	$71.01
2030	$61.77	$82.38	$71.66	$70.22	$77.51	$73.73

6.1.3 Benchmarking of Energy Model

The scope of work requested the following analyses of the AESC 2015 wholesale electric energy price forecast:

- Comparisons with other trends and forecasts, including comparisons to a trend of actual monthly prices from ISO-NE and a forecast as represented by the NYMEX futures market and the most recent relevant EIA forecast;
- A high-level discussion of reasons for differences identified in the comparisons; and
- Explanation of any apparent price spikes and key variables that affect the outcome, as well as identification of potential cases worthy of investigation.

6.1.4 ISO NE 2013 Actuals

TCR benchmarked the ability of its model to simulate the actual operation of the energy market by doing a “back cast” simulation of the ISO New England system for 2013. In that simulation, TCR used pCa to project hourly energy prices in 2013 using as inputs actual hourly loads by zone, actual interchange schedules between ISO-NE and neighboring systems, actual daily natural gas prices and estimated daily distillate and residual fuel oil prices derived from actual daily crude oil prices and TCR regression models. TCR compared its simulated prices to actual 2013 Day-ahead LMPs. The comparison of simulated prices by SMD Zone is presented in Exhibit 6-4. The solid bars in that Exhibit represent actual prices and the patterned bars represent simulated prices. As shown in that Exhibit, pCA model accurately captures the magnitudes and the locations spread of LMPs in New England over that historical time period.

Exhibit 6-4. Comparison of Actual and Simulated Locational Marginal Prices in ISO New England by SMD Zone (2015$/MWh)

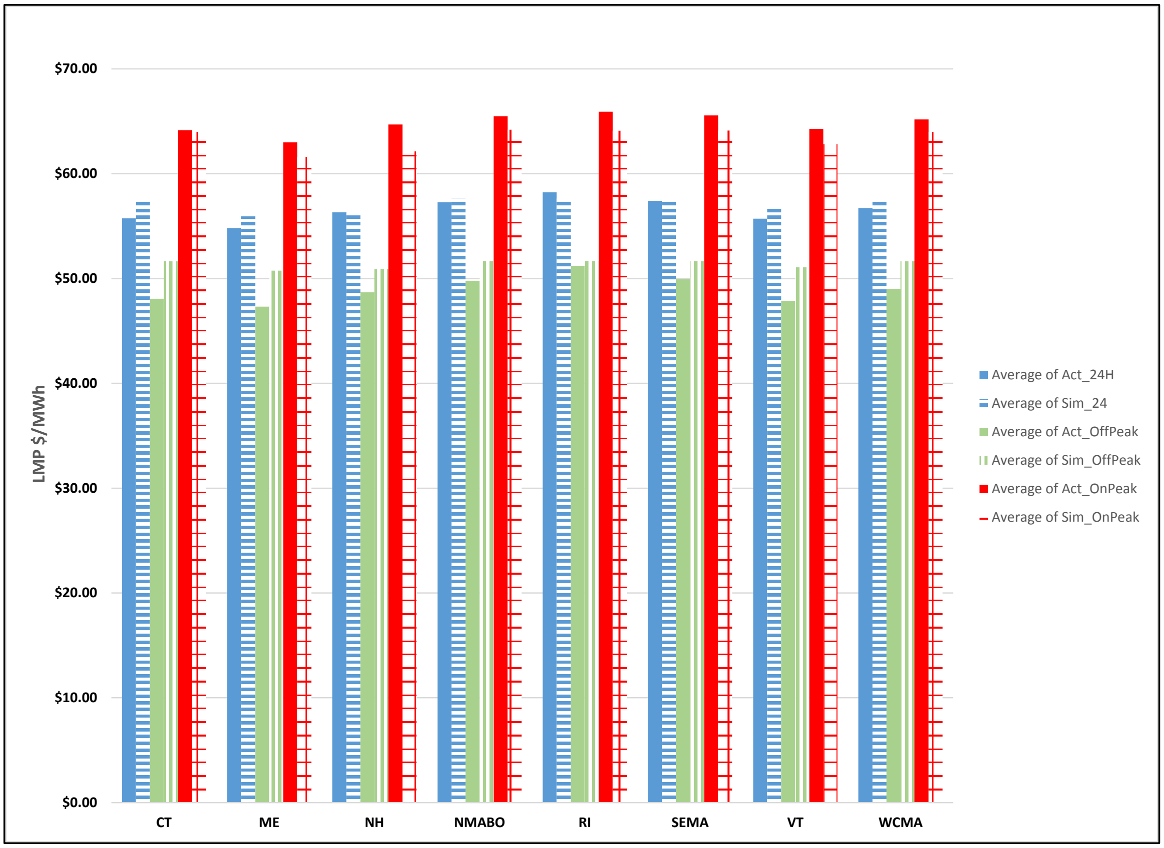
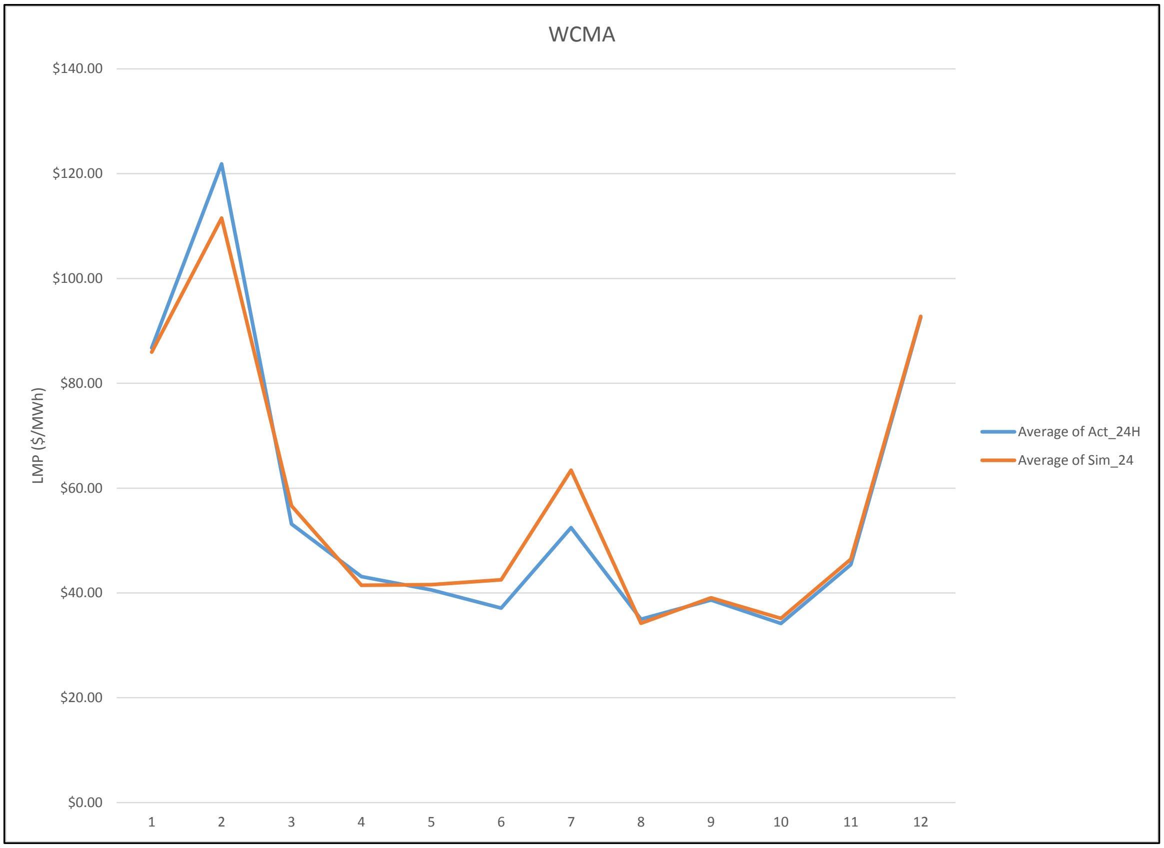


Exhibit 6-5 compares simulated and actual monthly prices for the WCMA Zone.

Exhibit 6-5. Comparison of Actual and Simulated Locational Marginal Prices in ISO New England, Monthly for WCMA Zone, 2015$/MWh



As shown in this Exhibit, the pCA simulation replicated actual price patterns in 9 out of 12 months. This benchmarking validates the pCA commitment and dispatch algorithms and the quality of the heat rate data provided by pCA vendor – Newton Energy Group. The simulations results somewhat under-estimated actual prices in February and over-estimated actual prices in June and July. This could be related to the difference between assumed and actual generator and transmission forced outages and maintenance schedules and well as other factors, such as operator discretion, which are difficult to fully represent in the model.

New England Hub Futures

TCR also benchmarked BAU/ simulation results for years 2015-2017 against futures prices for the New England Internal Hub as cleared on NYMEX on December 18, 2014. This clearing date coincides with the clearing date for natural gas and oil prices used in the development of fuel price inputs. The comparison of futures and projected On-Peak and Off-Peak prices is presented graphically in

Exhibit 6-6 and Exhibit 6-7 respectively. As these exhibits indicate, pCA projections well correspond to NYMEX futures both for on-peak and off-peak products.

Exhibit 6-6. On-Peak LMPs: Projection vs. Futures, 2015$/MWh

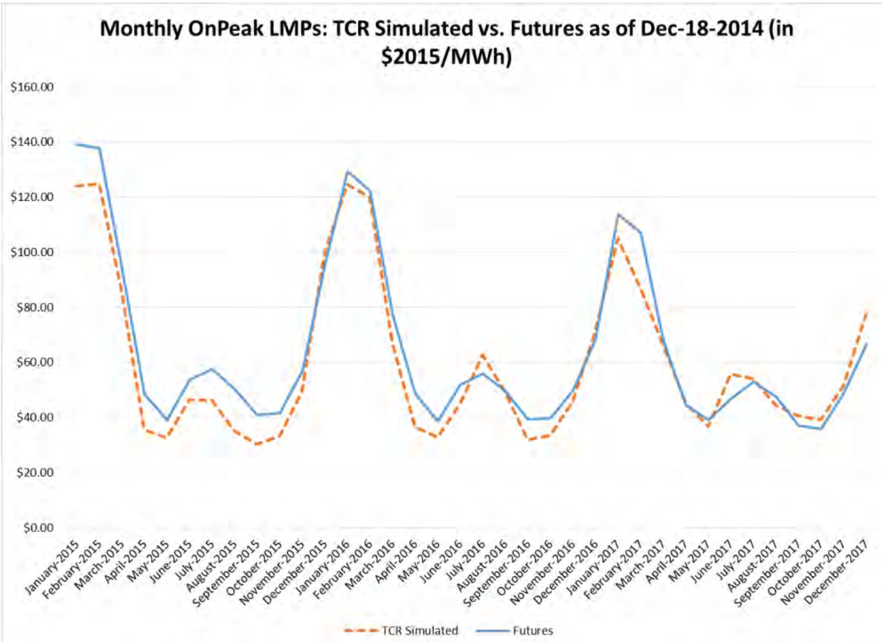
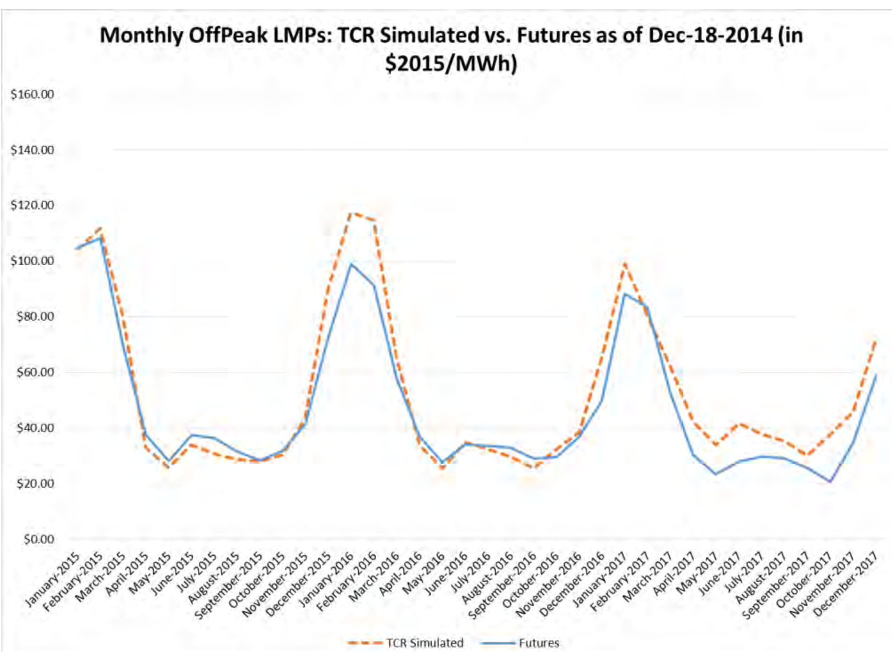


Exhibit 6-7. Off-Peak LMPs, Projections vs. Futures, 2015$/MWh



In sum, these benchmarking results demonstrate that the pCA modeling environment and supporting datasets provide a reliable tool for developing electric energy price projections.

Comparison to the Base Case

On a 15 year levelized basis, the Base Case avoided costs for Central Massachusetts are within 1 % of the BAU avoided costs, as shown in Exhibit 6-20. The levelized Base Case avoided costs are slightly lower than BAU avoided costs. The differences vary by seasons and time periods, ranging between 0.17% (summer off-peak) and negative 0.8% (winter peak).

Exhibit 6-8. 15-Year Levelized Cost Comparison for Central Massachusetts, Base Case v. BAU Case (2015$/MWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual All-Hours Energy
BAU Case	$62.59	$57.06	$57.89	$44.96	$56.87
Base Case	$62.10	$56.82	$57.68	$45.04	$56.58
% Difference	-0.8%	-0.4%	-0.4%	0.17%	-0.5%

A year-to year comparison of Base Case and BAU avoided costs for the summer and winter season is presented in Exhibit 6-9 and Exhibit 6-10, respectively. Avoided costs are identical in the first three years (2015-2017) since the load forecasts are identical during that period. Beyond 2017 the differences between the Base Case and BAU Case do not exhibit a consistent trend. As this comparison shows, the year-to-year deviations are small, especially during off-peak hours. Summer off-peak deviations are between -2% and +2%, winter – between -2% and +2%. On-peak fluctuations are bigger in magnitude, ranging between -9% and +7% in summer and between -3% and +3% in winter.

Exhibit 6-9. Base Case as a Percent Difference from the BAU Case, Summer Season Comparison

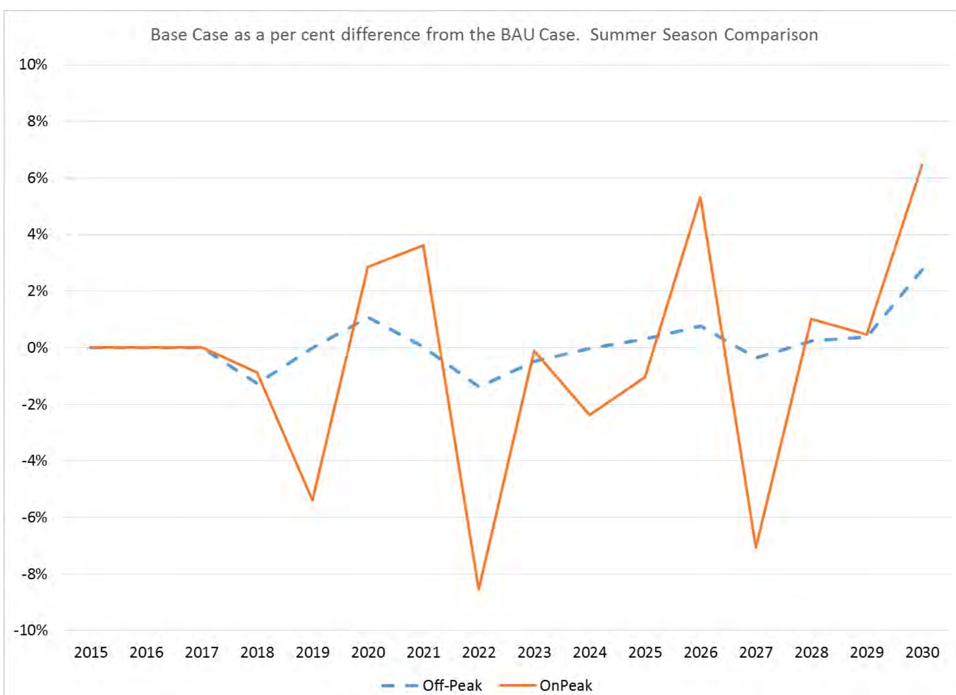
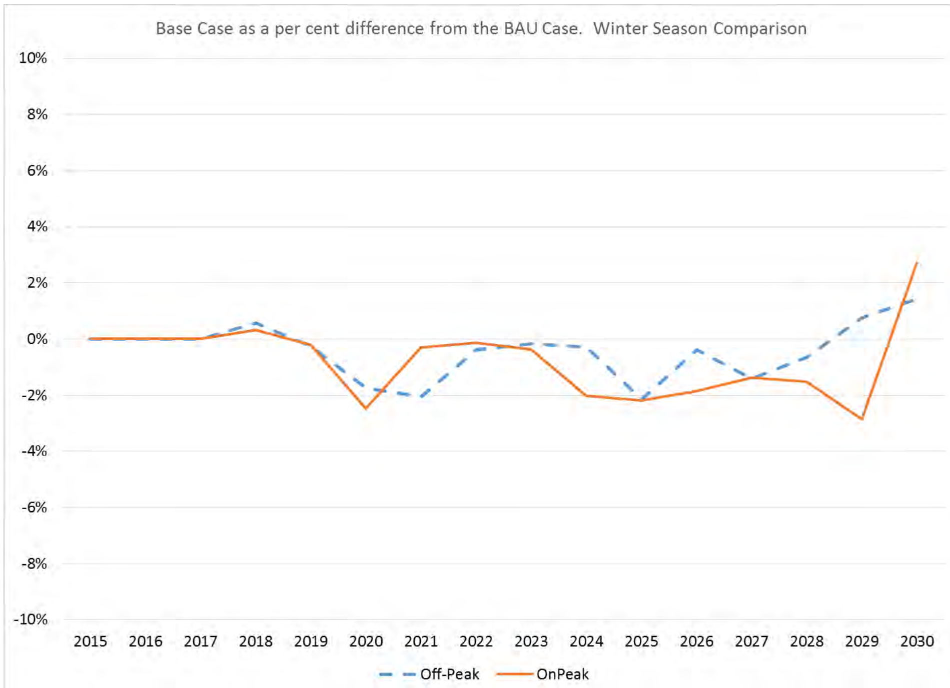


Exhibit 6-10. Base Case as a Percent Difference from the BAU Case, Winter Season Comparison



6.2 Explanation of BAU Case Results Relative to Base Case

In the long-term, from 2015 through 2029, AESC 2015 has not identified any material, statistically significant, difference in energy or capacity prices between the Base Case and the BAU case. We conclude that there is no long-term price suppression or DRIPE impact under the current outlook for the power system in New England.

The results of our two sets of simulations, and our conclusion, is explained by the following three major factors which are driving the DRIPE effect in the New England electric market over the study period:

- Close coordination between investments in energy efficiency and investments in capacity additions,
- Marginal sources of capacity with very similar cost characteristics, and
- A market which is in equilibrium.

The magnitude of the DRIPE effect of energy efficiency investments in a particular electric market over a given study period is dependent on three major conditions or factors in that particular market. The three factors are coordination between investments in energy efficiency and investments in capacity additions, cost characteristics of capacity additions, and whether the market is in surplus or in equilibrium.

Coordination of Energy Efficiency and Capacity Investments

In New England, investments in energy efficiency are well-coordinated with investments in new capacity additions and with decisions to retire existing capacity. The forward capacity auction (FCA) enables decisions to retire existing generating capacity and to add new generating capacity to be well coordinated with investments in energy efficiency. The FCA simultaneously clears energy efficiency investments, in the form of Passive Demand Resources (PDR) and investments in new generation capacity. As a result, investments in energy efficiency can have a virtually instantaneous impact on investments in new capacity additions.

Cost Characteristics of Capacity Additions

In New England, the marginal sources of new capacity are gas-fired combined cycle (CC) units and gas-fired combustion turbine (CT) units. All new gas CCs have very similar cost characteristics and all new gas CTs have very similar cost characteristics.

Market in Surplus or Equilibrium

Prior to 2013, the New England market was generally forecast to be in surplus; now it is forecast to be in equilibrium. DRIPE effects fall along a continuum: DRIPE is most likely to be material in an electric market in surplus and least likely to be material in an electric market in equilibrium.

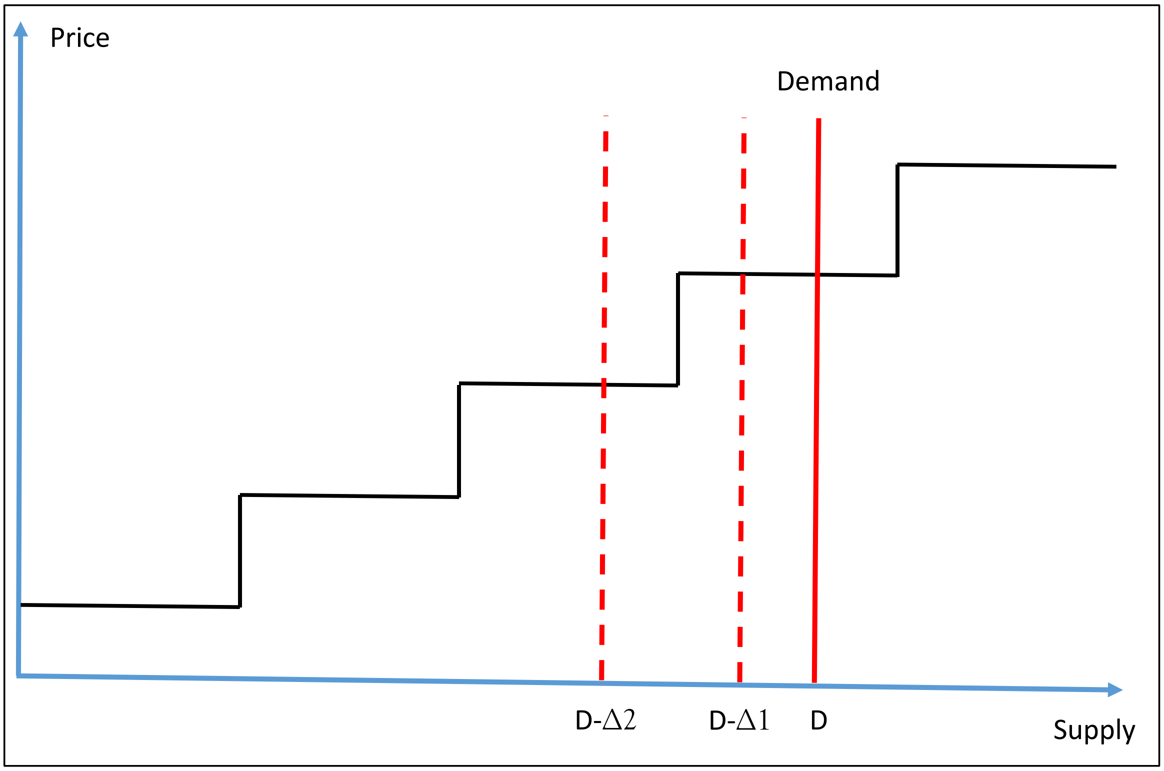
- In a power system which is in surplus, i.e., its existing generating capacity exceeds reserve requirements, investments in energy efficiency increase the level of surplus and delay the timing of new generating capacity additions. These incremental investments in energy efficiency tend to affect both capacity and energy markets. Energy efficiency reduces capacity prices through the delay of new additions; it reduces energy prices by reducing the need to use more expensive generation resources, which will be dispatched less frequently when demand is reduced

- In a power system which is in equilibrium, i.e., in which just enough new capacity is being added to meet reserve requirements, incremental investments in energy efficiency reduce the quantity of new capacity additions through FCA, and similarly reductions in energy efficiency investments increase the quantity of capacity additions through the FCA. As a result, increments or decrements in energy efficiency investments are unlikely to materially reduce prices in either the capacity or energy markets under equilibrium conditions. Capacity prices are not affected because capacity prices are set by new capacity additions, all of which have similar cost characteristics. Energy prices are not affected because the supply curve remains virtually the same relative to load—when demand increases (decreases), the supply curve expands (shrinks). The shape of the supply curve, however, remains virtually the same—which results in almost no impact on the marginal costs of serving the load.

6.2.1 Magnitude and Shape of Demand Reduction

As Exhibit 6-11 illustrates, very small levels of load reduction may not impact electricity prices. Their impact depends on the shape of the supply curve in the vicinity of the change in demand. As the exhibit shows, supply curves in the electric system are typically shaped as step functions with significant blocks of capacity offered to the market at the same price. As a result, a small reduction in electricity demand (Δ1 in the exhibit) causes no reduction in the price of electricity. To create a discernible price impact, the demand reduction must be sufficiently large (Δ2 in the exhibit). Furthermore, because supply curves are essentially non-linear, demand reductions of different magnitudes will result in different magnitudes of price reduction not only in absolute but also in relative terms. The relative price impact per MW of demand reduction associated with a 100 MW reduction will be different from the relative per MW price suppression associated with a 500 MW reduction.

Exhibit 6-11. DRIPE is Function of the Size and Shape of Load Reduction



The magnitude of the price impact of a load reduction during a specific time period also depends on the shape of that load reduction. The shape of the load reduction not only affects the price resulting from a shift along the supply curve, it can also affect the shape of the supply curve itself due to the unit commitment process, discussed in Section 5. 1. Because of the unit commitment process the supply, demand, price relationship in the New England energy market is much more complex than shown in Exhibit 6-11. A given day with a high load may have a supply curve that is different from the supply curve that would be used if the load on that day was much lower.

BAU Case vs Base Case

Exhibit 6-12 reports the difference in system-wide peak demand between the Base Case and the BAU Case. That difference ranges from 239 MW in 2018/19 to 2,531 MW in 2029/30.

Exhibit 6-12. Difference in System Peak Demand between Base Case and BAU Case

Period	Difference
2018/19	239
2019/20	464
2020/21	675
2021/22	873
2022/23	1,059
2023/24	1,233
2024/25	1,441
2025/26	1,653
2026/27	1,867
2027/28	2,085
2028/29	2,306
2029/30	2,531

Despite this large difference in projected demand, the projections of energy prices and capacity prices in the BAU Case are very close to those in the Base Case. On a 15-year levelized basis energy prices under the Base Case are 0.7% **lower** than under the BAU Case. Capacity prices under the Base Case are 0.09% lower than under the BAU Case. Thus there is virtually no direct relationship between the assumed reductions from new energy efficiency and prices.

Analysis of Energy Prices – BAU Case versus BASE Case

The lack of a material difference in prices under the two Cases can be attributed to the following factors:

- Absence of significant transmission congestion effectively combining all generating resources into a single supply stack serving the entire market
- Significant reliance of the New England on combined cycle gas fired generation technology driving prices in the majority of hours
- A market in equilibrium in which long-term increases (decreases) in demand are matched with corresponding increases (decreases) in capacity additions

Absence of significant transmission congestion creates a competitive electricity market in which geographically dispersed generating resources could compete for serving electricity demand in all states and zones almost all the time. As a result, the supply stack in New England is effectively market wide and not fractured into smaller sub-zones.

Exhibit 6-13 presents the supply stack and load duration curve for the New England system as modeled for the month of July of 2025 under the BAU Case. This exhibit shows supply (a blue curve) and demand (a red curve) measured in MW along the horizontal axis. Two vertical axes in this exhibit show short-run production costs (left axis) for the supply curve and hours (right axis). The supply curve here is a “real” supply stack already accounting for generator outages and for average availability for hydro and renewable resources. The first flat zero cost portion of the supply stack represents hydro, wind and solar generation. The second flat segment primarily corresponds to nuclear capacity, the third and the largest flat portion of the supply stack corresponds to the combined cycle technology.

A vertical line connecting the load curve with the supply curve identifies the “marginal cost” of serving that level of supply. Letters A through E positioned along the demand curve identify different segments of that curve with different generating technologies on the margin. Thus, for segment A – B, marginal technology will be hydro and nuclear, for B – C – biomass, cogeneration, refuse and other technologies that have lower costs than CCs. For C – D the marginal technology is CC and for D – E – gas –fired and oil-fired peakers. The bars along the y (hours) axis indicate number of hours the technology is considered marginal. Peakers appear marginal for approximately 70 hours out of 744 (9% of the time); CCTGs appear marginal for approximately 510 hours (69% of the time). The remaining 22% of low load hours are typically hours when baseload generators are dispatched at minimum operating conditions with some of baseload technologies being on the margin.

Exhibit 6-13. Generation Supply Stack. BAU Case, July 2025

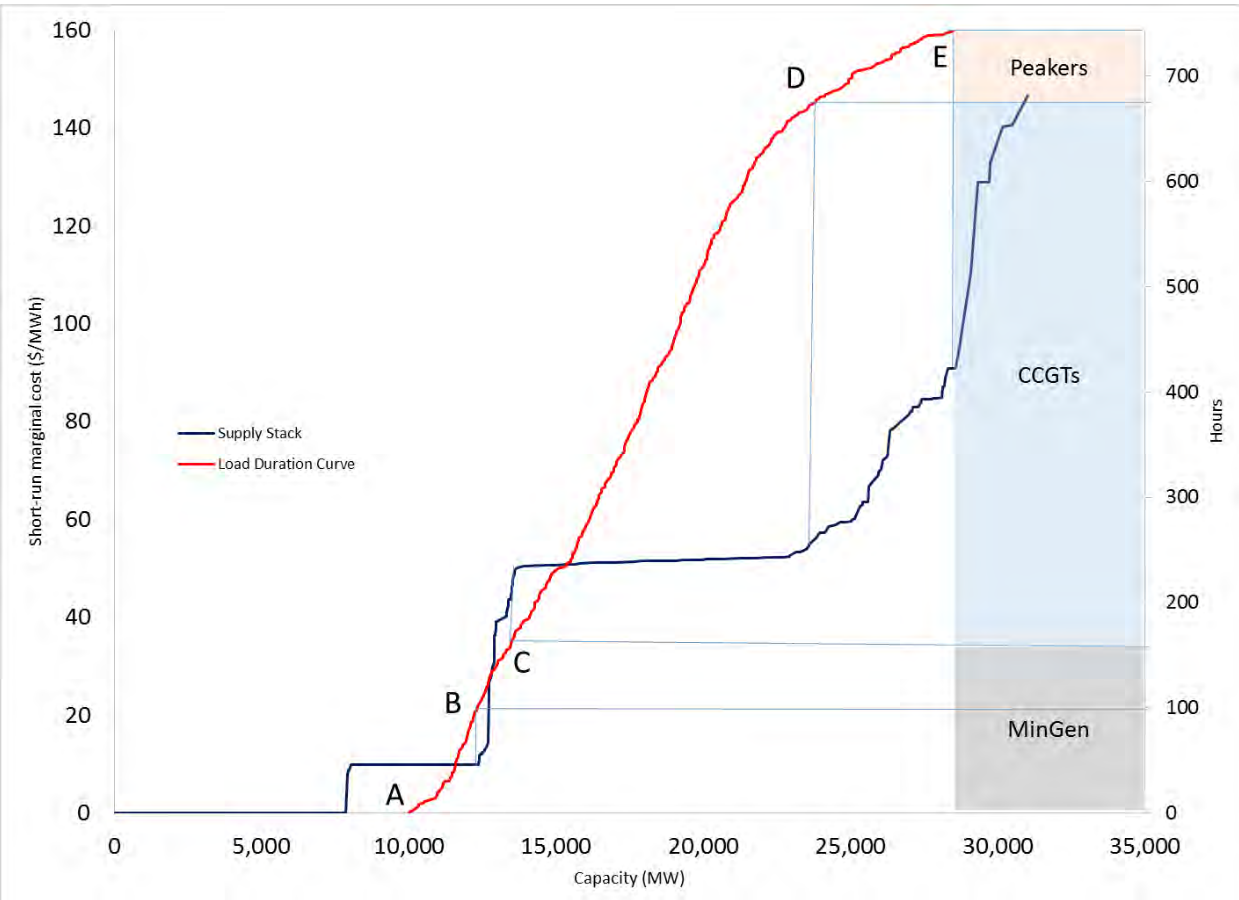
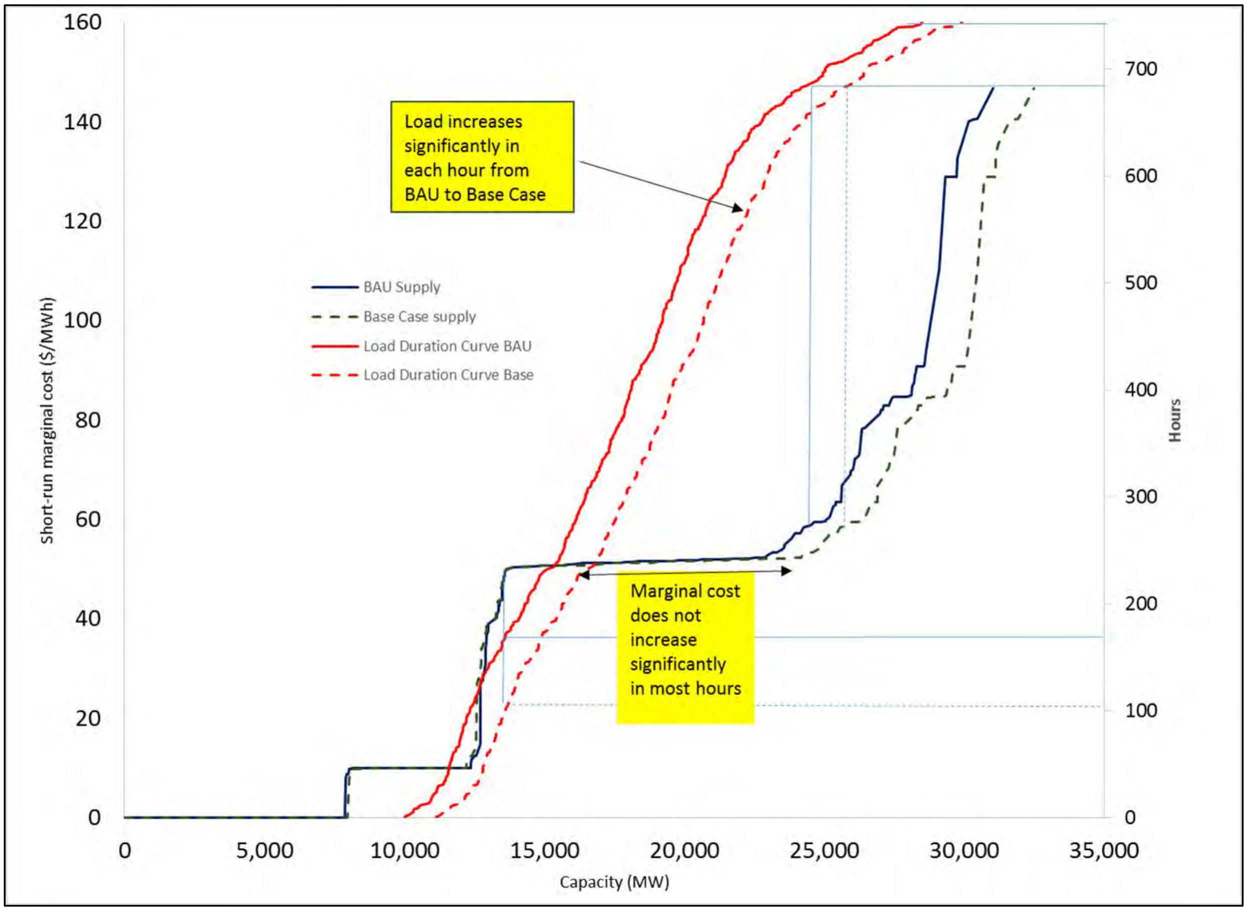


Exhibit 6-14 compares supply stacks and load duration curves under the BAU and Base Cases. Base Case characteristics are represented by dashed lines. As shown in this exhibit, the Base case supply stack is similar to the BAU Case but in a very special way. The parts of the stack that are left of the combined cycle segment are almost identical.

Under the Base Case demand curve shifts to the right, but so does the portion of the supply curve – combined cycle segment gets extended and portion to the right of the combined cycle segment shifts to the right. What is important here is that under both cases the number of hours when peaking units, typically CTs, are on the margin (segments D-E and D'-E') is approximately the same. Under the Base Case, the number of hours when CCs are theoretically on the margin (segment C' – D') is bigger than under the BAU scenario. However, some of these hours are low load hours. In other words, Exhibit 1-5 demonstrates that although Base Case load exceeds the BAU load by over 1400 MW, the short-run marginal costs of serving the load in the Base Case and BAU case are essentially the same.

Exhibit 6-14. Supply Stacks BAU and Base Cases, July 2025

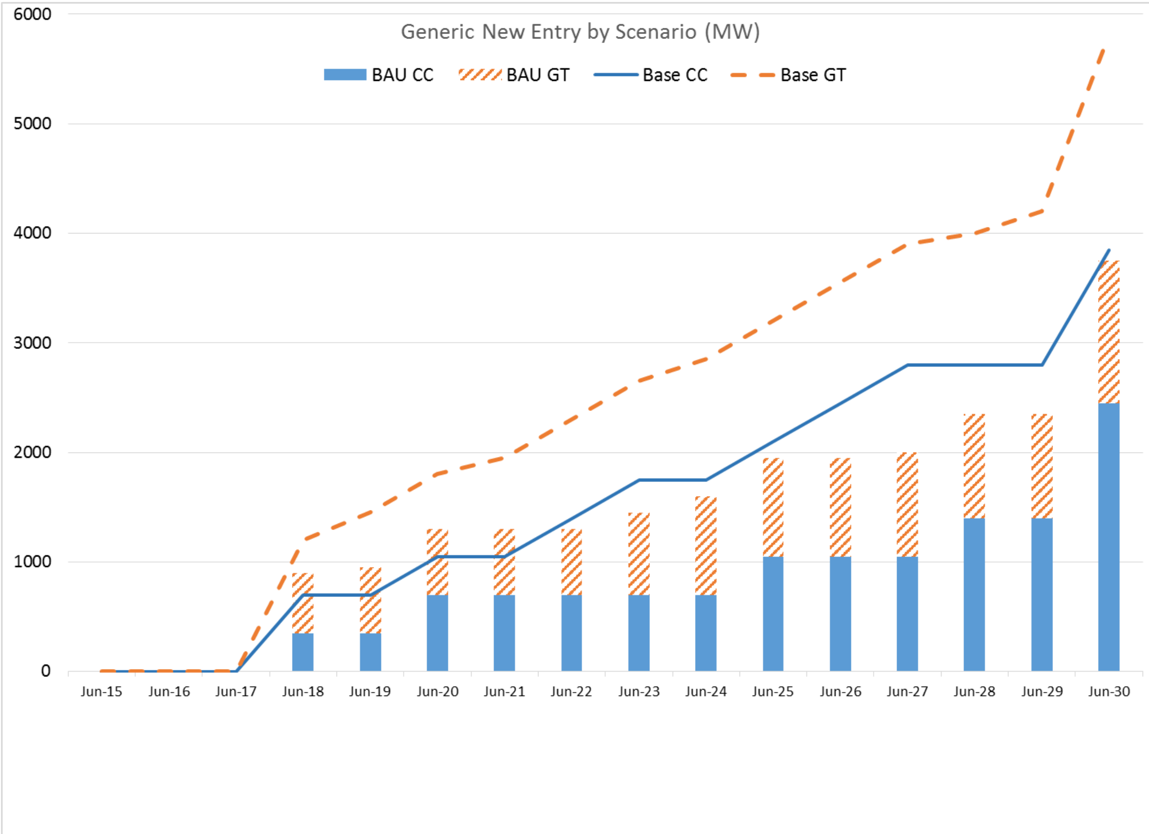


Analysis of Capacity Prices – BAU Case versus BASE Case

Starting with FCA #9 (2018/19) capacity prices in New England are driven by the cost of new entry reflecting the system need for new capacity[178]. To meet system-wide and locational installed capacity requirements, AESC 2015 added new capacity in the form of combined cycle or (CC) and simple cycle (CT) gas-fired generating units. The dynamics of generic capacity additions under both scenarios is shown in Exhibit 6-15.

[178] When TCR prepared its capacity price projections, the FCA 9 results for 2018/19 were not known. However, the avoided electricity costs in Appendix B are based on FCA9 results for 2018/19.)

Exhibit 6-15. Additions of Generic New Capacity under Base and BAU Cases



Simulated capacity prices begin with FCA#9 (2018/19). The differences between capacity prices over the 2018/19 to 2029/30 period is within a plus/minus 6% range each year. However, on average over 15 years levelized capacity prices are within 0.09%.

Exhibit 6-16. Capacity Prices – BAU Case vs. BASE Case

	ASEC 2015 BAU	AESC 2015 Base	Base Case vs BAU Case
	2015$/kW-month	2015$/kW-month	% difference
2015/16	3.38	3.38	0.00%
2016/17	3.15	3.15	0.00%
2017/18	14.19	14.19	0.00%
2018/19	13.13	12.96	-1.27%
2019/20	11.54	11.29	-2.17%
2020/21	11.45	11.33	-1.08%
2021/22	11.21	11.71	4.48%
2022/23	11.87	11.62	-2.11%
2023/24	11.87	11.37	-4.23%
2024/25	12.04	11.96	-0.69%
2025/26	11.29	11.96	5.93%
2026/27	12.04	12.04	0.00%
2027/28	12.54	11.79	-6.00%
2028/29	11.79	12.46	5.67%
2029/30	12.54	12.79	2.00%
15 yr Levelized	10.76	10.75	-0.09%

Market Equilibrium

AESC 2015 considers the New England capacity market to be in equilibrium through the operation of the Forward Capacity Auctions (FCAs). The FCAs are designed to acquire just enough new capacity for a given power year to meet the reserve requirements for that year. Those auctions give supply-side resources and demand-side resources the opportunity to bid to provide that additional capacity. As a result, in any given FCA, the greater the reduction from investments in energy efficiency that is bid in, i.e. "passive demand resources (PDR), the lower the quantity of supply side resources will be selected. Similarly, the lower the level of PDRs that is bid in, the greater the quantity of supply side resources will be selected. Under these market conditions increments or decrements in energy efficiency investments are unlikely to materially reduce prices in either the capacity or energy markets under. Capacity prices are not affected because capacity prices are set by new capacity additions, all of which have similar cost characteristics. Energy prices are not affected because the supply curve remains virtually the same relative to load. Under a Case in which demand increases, the supply curve expands correspondingly. Under a Case when the demand does not increase, the supply curve does not increase. However, the shape of the supply curve remains virtually the same under each Case. As a result, the marginal costs of serving the load is essentially the same under each Case.

It is possible that the New England capacity market might not be in equilibrium in a given year but we do not believe that circumstance would result in DRIPE values materially higher than our estimates for several reasons.

First, for the market to be in a material surplus year after year, PAs would have to not be bidding a material percent of their efficiency reductions into the FCAs causing actual demand to be materially less than ISO NE forecast year after year, such that ISO NE would continue to acquire more new capacity in each FCA than was ultimately required to be brought on year after year. It is not reasonable to assume ISO NE would fail to notice these material discrepancies. On the contrary, ISO NE is clearly aware of this possibility, as indicated by the following text from Energy Efficiency Forecast 2018 to 2023 (footnotes excluded):

Given the significant changes that have occurred in the New England EE programs over the past 10 years, some New England states believed that significant EE resources that had been developed as a result of state-sponsored EE programs did not participate in the FCM and were therefore unaccounted for by the ISO. To address this issue, in 2011, the ISO conducted a detailed survey of the region's EE program administrators concerning their participation in the FCM. The results of this analysis showed that essentially all the EE capacity the PAs developed was indeed participating in the FCM. While stakeholders indicted that other non-regulated entities may be engaged in deploying EE through performance contracts, these projects were small relative to the state-funded programs. Consequently, the projections of EE in the ISO's planning process only focus on state-sponsored EE programs.

> 2.3 Development of the Energy-Efficiency Forecast
>
> In addition to the one-to-four-year planning timeframe of the FCM, the ISO routinely plans and forecasts energy and demand looking 10 years into the future, but grid planners had assumed constant levels of EE in the long-term planning, four to 10 years out. This resulted in the planning assumption that there would be no additional growth in EE beyond the FCM. Concerned that the presumption of constant levels of future EE, beyond the FCM horizon, would not capture the anticipated growth in EE resources from year to year, stakeholders and the ISO investigated possible methods to forecast future savings in the annual and peak use of electric energy from EE programs.
>
> Beginning in 2009, the ISO and the region's energy-efficiency stakeholders conducted an intensive, multiyear research, data-collection, and analysis process resulting in a comprehensive assessment of historical spending on EE programs by PAs. The study analyzed EE programs and studied how to model incremental, future long-term EE savings for four to 10 years into the future. This deliberate and analytic effort advanced the anecdotal understanding of EE to empirical knowledge about production costs, spend rates, realization rates, and performance at the program level. The result of this effort was a fully vetted approach to accounting for future EE investment and savings and the nation's first regional (multistate) long-term forecast of energy efficiency. The current EE forecast now equips system planners and stakeholders with reliable information about the long-term impacts of state-sponsored EE programs.

Second, if actual demand in a given year was less than the forecast for that year would have little or no effect on capacity prices in that year or subsequent years. First, capacity prices are set through FCAs that are run 3 years in advance of the power year. Second, the categories of new capacity being added have the same cost and operating characteristics.

6.3 High Gas Price Case

The High Gas Price case assumes a higher Henry Hub price forecast than the AESC 2015 Base Case and less new pipeline capacity additions to serve New England over the study period than the Base Case.

- Those two assumptions result in higher avoided wholesale gas supply costs in New England than under the Base Case. For example, the 15 year levelized wholesale city-gate cost of gas under the high gas price Case is $ 7.03/MMBtu (2015$), 18% higher than under the Base Case.
- Those higher avoided wholesale gas supply costs also result in correspondingly higher avoided wholesale electric energy costs. For example the 15 year levelized avoided wholesale electric energy cost in central Massachusetts under the high gas price Case is $65.09/MWh (2015$), 17% higher than under the Base Case.
- The avoided electric capacity costs under the High Gas Price case are essentially the same as under the AESC 2015 Base Case.

The AESC 2015 high gas price Case reflects two major differences in assumptions from the Base Case, as summarized in Exhibit 6-17.

Exhibit 6-17. Major assumptions in AESC 2015 Base Case and High Gas Price Case

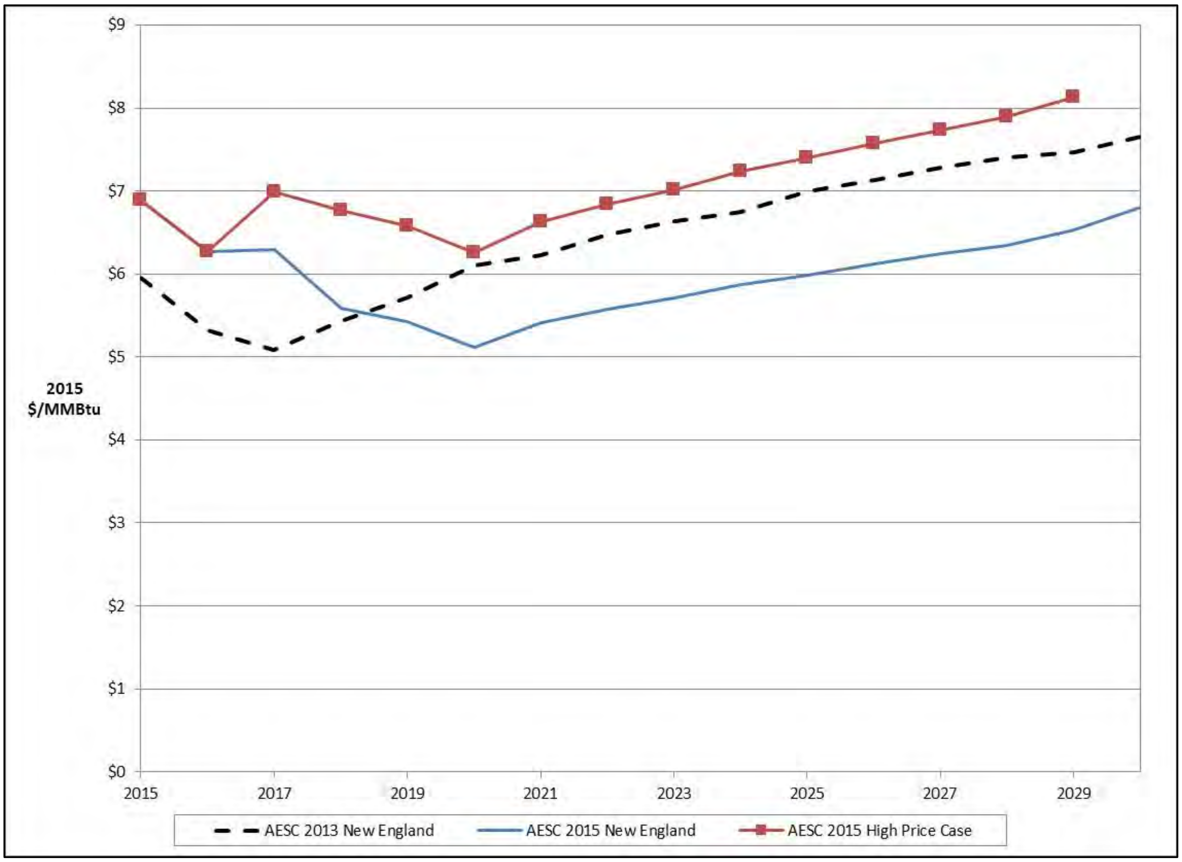
Assumption	Base Case	High Price Case
Henry Hub Prices	NYMEX Futures through 2016, AEO 2014 Reference Case from 2017 onward	NYMEX Futures through 2016, AEO 2014 Reference Case plus 15% from 2017 onward.
New pipeline capacity able to deliver gas to New England from producing areas west of New England	AIM &Tennessee CT expansions enter service 11/2017 (0.4 Bcf/day); Kinder Morgan capacity expansion enters service 11/2018 11/2018 (0.6 Bcf/day)	AIM &Tennessee Connecticut pipeline expansions enter service in 11/2017 (0.4 Bcf/day).

The High Gas Price Case reflects less aggressive shale gas development than under the Base Case and less gas pipeline capacity expansion. It assumes LDC load in New England will grow supplied by the new pipeline capacity that is added and additional supplies of LNG. Internationally, LNG prices ease as non-U.S. supplies increase and demand falls as Asia Pacific countries complete nuclear plants non-Mediterranean Europe replaces high-cost gas supplies with coal and, eventually, nuclear power and renewables.

This Case contrasts with the AESC 2015 Base Case, in which a broad array of U.S. dry gas-prone shale regions continue to develop, and Marcellus/Utica gas production rises to approx. 25 Bcf/day by 2020. All currently subscribed pipeline capacity proceeds to construction and enters service before 2020, as described in the Task 3A report. LNG market prices fall only slightly, remaining costly, thus LDC growth is limited to levels enabled by expanded gas pipeline capacity.

Exhibit 6-18 presents a year-by-year comparison of the avoided wholesale city-gate cost of gas under the High Gas Price Case and the Base Case respectively. The major difference in avoided costs between the two Cases begins in 2017 for two reasons. First, Henry Hub prices under both Cases are based on NYMEX futures through 2016. Second, pipeline capacity into New England under both cases is the same through November 2018.

Exhibit 6-18. Annual Wholesale City-Gate Cost of Gas in New England High Price Case vs. Base Case ($/MMBtu) (2015$)



6.3.1 Electric Energy Prices under the High Gas Price Case

On a 15 year levelized basis, the High Gas Case avoided electric energy costs for Central Massachusetts are 18% higher than the Base Case avoided costs, as shown in Exhibit 6-20. The magnitude of High Gas Case avoided cost increases above the Base Case varies by pricing zone, season and time period, ranging between 8.8% (summer peak) and 21% (winter off-peak).

Exhibit 6-20. New England wholesale gas costs and Electric Energy Prices, High Gas Case vs Base Case

Year	Annual Wholesale Gas Price, AGT hub (2015$/MMBtu)				Annual Energy Price, WCMA (2015$/MWh)			
	CASES		High Gas Case - Base Case		CASES		High Gas Case - Base Case	
	Base	High Gas	absolute difference	% change from Base Case	Base	High Gas	absolute difference	% change from Base Case
	a	b	c = b - a	d = c / a	e	f	g = f - e	h = g / e
2015	$ 6.96	$ 6.96	$0.00	0%	$57.59	$57.59	$0.00	0%
2016	$ 6.32	$ 6.32	$0.00	0%	$55.62	$55.62	$0.00	0%
2017	$ 6.33	$ 7.02	$0.69	11%	$54.99	$57.46	$2.48	5%
2018	$ 5.59	$ 6.78	$1.19	21%	$48.83	$60.04	$11.21	23%
2019	$ 5.43	$ 6.59	$1.16	21%	$48.24	$59.37	$11.13	23%
2020	$ 5.13	$ 6.27	$1.15	22%	$47.00	$57.68	$10.68	23%
2021	$ 5.42	$ 6.64	$1.22	22%	$49.42	$61.03	$11.61	23%
2022	$ 5.58	$ 6.85	$1.27	23%	$52.17	$63.88	$11.71	22%
2023	$ 5.72	$ 7.04	$1.32	23%	$54.23	$65.93	$11.70	22%
2024	$ 5.88	$ 7.25	$1.37	23%	$56.11	$68.07	$11.96	21%
2025	$ 5.99	$ 7.41	$1.42	24%	$59.26	$71.81	$12.55	21%
2026	$ 6.12	$ 7.59	$1.47	24%	$61.51	$74.15	$12.64	21%
2027	$ 6.25	$ 7.76	$1.51	24%	$62.52	$75.02	$12.51	20%
2028	$ 6.35	$ 7.91	$1.56	24%	$64.88	$77.63	$12.75	20%
2029	$ 6.54	$ 8.15	$1.61	25%	$68.46	$80.88	$12.42	18%
2030	$ 6.81	$ 8.48	$1.68	25%	$75.24	$87.93	$12.68	17%
15 yrs Levelized (2016-2030)								
	$5.94	$7.14	$1.21	20%	$56.58	$66.83	$10.25	18%

Exhibit 6-20 and **Exhibit 6-21** present year-by-year comparisons of avoided energy costs under the High Gas Price Case and the Base Case respectively. The major difference in avoided energy costs between the two Cases begins in 2017 because city-gas gas prices are basically the same under both Cases through 2016 for the reasons discussed above. After 2016 the summer differences between the High Gas Price Case and Base Case fluctuate between 7% and 12 % during On-peak hours and between 10% and 13% in off-peak hours. In winter, under the High Gas Price case, avoided costs are 6%-8% above the Base Case in 2017 and 20% - 30% above Base Case in 2018 and beyond.

It is also worth noting that in relative terms, higher gas prices have a greater impact on electric avoided costs during off-peak hours than during on-peak hours. In absolute terms, over the long-term in a given season the changes in on-peak and off-peak prices are of similar magnitude, as shown in Exhibit 6-20.

Exhibit 6-20. High Gas Case as a Percent Difference from the Base Case, Summer Season Comparison

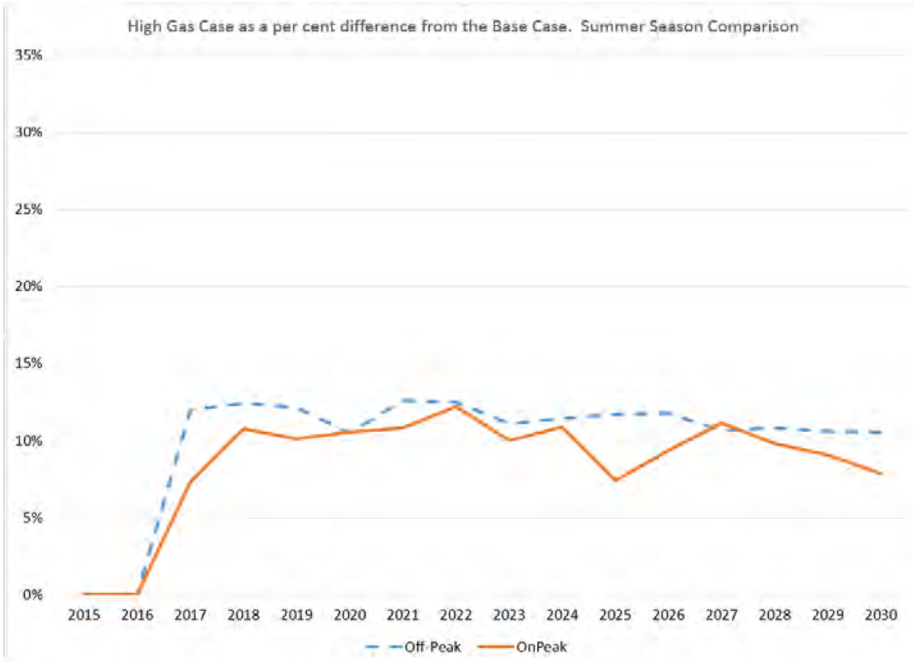
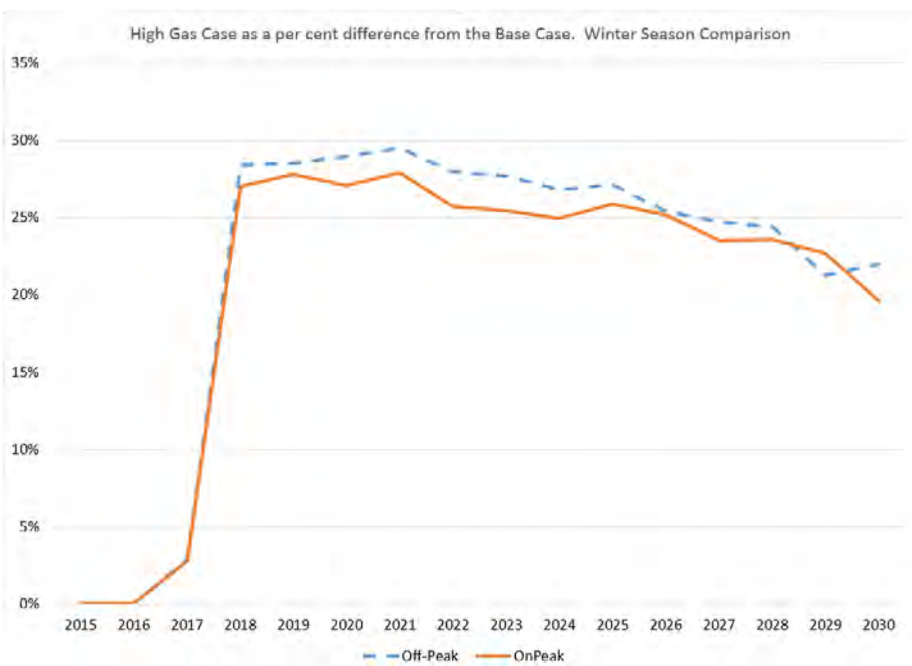


Exhibit 6-21. High Gas Case as a Percent Difference from the Base Case, Winter Season Comparison



6.3.2 Electric Capacity Prices under High Gas Price Case

The projected level and mix of capacity in the High Gas Price Case is identical to that of the Base Case. As a result, as shown in Exhibit 6-22, the avoided capacity costs under the High Gas Price Case are very close to those under the Base Case. Capacity prices are set by marginal capacity units – newly constructed CT generators which earn little net revenues in the energy market. Since both Cases have the same generation mix and identical patterns of new entry, the revenue requirements that new capacity bid into the capacity market are very similar under both the Base Case and the High Gas Price Case.

Exhibit 6-22. Capacity Prices under High Gas Price Case and Base Case

	ASEC 2015 High Gas	AESC 2015 Base	Base Case vs BAU Case
	2015$/kW-month	2015$/kW-month	% difference
2015/16	3.38	3.38	0.00%
2016/17	3.15	3.15	0.00%
2017/18	14.19	14.19	0.00%
2018/19	12.96	12.96	0.00%
2019/20	11.29	11.29	0.00%
2020/21	11.06	11.33	2.44%
2021/22	11.71	11.71	0.00%
2022/23	11.62	11.62	0.00%
2023/24	11.37	11.37	0.00%
2024/25	11.96	11.96	0.00%
2025/26	11.96	11.96	0.00%
2026/27	12.04	12.04	0.00%
2027/28	11.79	11.79	0.00%
2028/29	12.46	12.46	0.00%
2029/30	12.79	12.79	0.00%
15 yr Levelized	10.73	10.75	0.18%

Chapter 7: Demand Reduction Induced Price Effect

7.1 Introduction

DRIPE refers to the reduction in wholesale market prices for energy and/or capacity expected from reductions in the quantities of energy and/or capacity required from those markets during a given period due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency received by all retail customers during a given period in the form of expected reductions in wholesale prices.

DRIPE effects are typically very small when expressed in terms of their impact on wholesale market prices, i.e., reductions of a fraction of a percent. However, DRIPE effects may be material when expressed in absolute dollar terms, e.g., a small reduction in wholesale electric energy price multiplied by the quantity of electric energy purchased for all consumers at that wholesale market price, or at prices / rates tied to that wholesale price.

- The avoided cost value of DRIPE during a given time period is equal to the projected impact on the wholesale market price during that period, expressed as a $ per unit of energy, multiplied by the quantity of energy purchased at rates or prices tied directly to that given market price. As illustrated in

Exhibit 7-1, this chapter calculates the avoided cost value of three broad categories of DRIPE:

- **Electric efficiency direct DRIPE:** The value of reductions in retail electricity use resulting from reductions in wholesale electric energy and capacity prices from the operation of those wholesale markets.
- **Natural gas efficiency direct and cross-fuel DRIPE:** The value of reductions in retail gas use from reductions in wholesale gas supply prices and reductions in basis to New England. Gas efficiency cross-fuel DRIPE is the value of the reductions in those prices in terms of reducing the fuel cost of gas-fired electric generating units, and through them wholesale electric energy prices.
- **Electric efficiency fuel-related and cross-fuel DRIPE:** The value of reductions in retail electricity use from reductions in wholesale gas supply prices and reductions in basis to New England. The reductions in those prices reduces the fuel cost of gas-fired electric generating units, and through them wholesale electric energy prices. Electric efficiency cross-fuel DRIPE is the value of the reductions in the wholesale gas supply price to retail gas users.

Exhibit 7-1. Overview of Impacts of wholesale DRIPE

Reduction in Retail Load	Cost Component Affected	DRIPE Category	Exhibit Reporting Results
Electricity	Electric Energy Prices	Own-price (energy DRIPE)	
Natural Gas	Gas Production Cost	Own-price (gas Supply DRIPE)	
	Gas Production Cost	Cross-fuel (gas to electric)	
	Basis to New England	Cross-fuel (gas to electric)	
Electricity	Gas Production Cost	Own-price (gas Supply DRIPE)	
	Basis to New England	Own- price (basis DRIPE)	
	Gas Production Cost	Cross - fuel (electric to gas)	

The AESC 2015 DRIPE results are lower than the corresponding AESC 2013 DRIPE results. The electric efficiency direct DRIPE results are lower primarily because the New England market is not projected to have surplus capacity during the study period and because AESC 2015 has reflected this change in market condition on a forward looking basis using a differential approach based on a direct simulation of these projected market conditions. The natural gas efficiency direct and cross-fuel DRIPE results and the electric efficiency fuel-related and cross-fuel DRIPE results are lower primarily because of the lower AESC 2015 estimate of basis.

This chapter describes the methods and assumptions AESC 2015 used to calculate electric and gas DRIPE effects, and the results of those calculations. This chapter is organized as follows:

- Section 7.2 describes the methods, assumptions and calculation of wholesale electric DRIPE.
- Section 7.2.4 describes the methods, assumptions and calculation of wholesale gas DRIPE.
- Section 7.4 describes the methods, assumptions and calculation of direct DRIPE effects from electric efficiency on retail customers.
- Section 7.5 describes the methods, assumptions and calculation of gas supply and gas basis DRIPE effects of gas efficiency and of electric efficiency.
- Section 7.6 describes the calculation of own-price and cross-fuel DRIPE effects from gas efficiency.
- Section 7.7 describes the calculation of own-fuel and cross-fuel fuel DRIPE effects from electric efficiency.

7.2 Wholesale Electric DRIPE

This section describes the AESC 2015 projections of the size of the capacity and energy price effects, provides empirical evidence which confirms these projections are reasonable, and explains why the projections are smaller than those in AESC 2013. As explained below, Section 6-10 provides an explanation of why our projections of electricity DRIPE duration is shorter than the AESC 2013 projection.

7.2.1 Overview

The value of DRIPE is a function of the projected impact of a given load reduction on wholesale capacity and/or energy market prices, and the projected duration of those price effects. Analysts cannot directly measure either the size of the price effect, or its duration. Instead analysts must estimate both of those two driving actors using some form of “counterfactual”. For example, looking back in time we know the actual energy prices in 2013 but we do not know the counterfactual, i.e., what energy prices would have been in 2013 had load been higher due to less reduction from efficiency measures. Looking forward, we do not know future prices. However, we can project market prices under a Case that assumes some level of reductions from continued ratepayer funding of efficiency and also project market prices under a “counterfactual” Case without those assume reductions. We can then estimate the size of the DRIPE effect on prices, and the duration of that DRIPE effect, by comparing the projections of market prices under the two Cases.

The analytical approach most commonly used to estimate DRIPE, or price suppression, is a “differential approach” based on market simulations. A list of studies which have estimate DRIPE and price suppression is provided in in Tables 1 and 2 of Appendix A. The other, less common, approach is regression analysis. Under that approach the analyst determine the relationship between electric prices and load during a past period and then use that relationship to forecast DRIPE based on an assumption that the historical relationship will apply in the future.

AESC 2015 estimated electricity DRIPE in New England, both capacity and energy, by projecting market prices under several different cases. AESC 2015 used the BAU Case, described in Chapter 6, as the reference point against which it measured the size and duration of DRIPE effects under each of the other Cases. The other cases are the BAU Case, described in Chapter 5, and state-specific DRIPE Cases for each New England state, which we will describe in this section. AESC developed the projections of market prices for each Case directly by simulating the operation of the market for the load forecasts used in that Case. The projected electric DRIPE effects from this approach are smaller than those projected in AESC 2013 because the projected price effects are smaller in size and shorter in duration.

AESC 2015 is projecting the price effects to be shorter in duration for the reasons presented earlier in the comparison between the Base Case and the BAU Case in Section 6.10. In summary, the projected shorter duration is attributable to differences between the two studies in terms of projected market conditions and differences in analytical approach. AESC 2015 projects that ISO-NE will begin adding gas-fired capacity in all zones starting in the 2018/19 power year under both the Base Case and the BAU

Case, approximately 3 years earlier than ASESC 2013. Also, AESC 2015 developed its projections of capacity and energy DRIPE from 2018 onward directly using simulation modelling of the energy market. The AESC 2013 projections of energy DRIPE duration are based on qualitative estimates of price effect duration.

Size of Electricity DRIPE effects

AESC 2015 is projecting a capacity price DRIPE effect of zero. In the short term ISO-NE has already set capacity prices through the 2018 power year. In the long term, as discussed in Section 6.10, ISO-NE has designed its auctions to avoid acquiring surplus capacity and because the cost characteristics of the new gas CT and CC units that will be setting the capacity market price are essentially the same. Note, however, that AESC 2013 is projecting much higher capacity prices than AESC 2013.

AESC 2015 is projecting energy DRIPE effects from January 2015 through May 2018. During that period all Cases rely on the same installed capacity, i.e., there is no difference in new generation additions or retirements. As a result, the difference in demand between the Cases is the primary driver of energy prices.

Exhibit 7-2. Incements in state DRIPE cases, 2017 provides an illustration of the levels of increments used in each state specific DRIPE Case, from 2017. These levels are small relative to total ISO-NE load. They vary in size and shape by state.

Exhibit 7-2. Incements in state DRIPE cases, 2017

Summer		CT	MA	ME	NH	RI	VT	ISO-NE Total
BAU Case Peak	MW	7,319	12,743	2,016	2,603	1,836	1,003	27,520
BAU Case load	GWh	12,058	21,910	4,010	4,379	2,968	2,011	47,336
Load Factor	%	56%	59%	68%	57%	55%	68%	59%
State-Specific DRIPE Cases								
PDR Increment	GWh	846	2,121	410	192	372	301	
PDR as % intrastate load	%	7.0%	9.7%	10.2%	4.4%	12.5%	14.9%	
PDR as % ISO-NE Total	%	1.8%	4.5%	0.9%	0.4%	0.8%	0.6%	
PDR Increment	MW	421	1077	184	97	179	132	
PDR load factor	%	69%	67%	76%	68%	71%	78%	
Winter		CT	MA	ME	NH	RI	VT	ISO-NE Total
BAU Case Peak	MW	5,530	9,659	1,789	2,041	1,250	974	21,243
BAU Case load	GWh	21,242	38,928	7,540	8,013	5,082	3,983	84,788
Load Factor	%	66%	69%	72%	67%	70%	70%	68%
State-Specific DRIPE Cases								
PDR Increment	GWh	1,489	3,776	770	351	638	595	
PDR as % intrastate load	%	7.0%	9.7%	10.2%	4.4%	12.5%	14.9%	
PDR as % ISO-NE Total	%	1.8%	4.5%	0.9%	0.4%	0.8%	0.7%	
PDR Increment	MW	270	1006	171	79	175	131	
PDR load factor	%	95%	64%	77%	76%	62%	78%	
Annual		CT	MA	ME	NH	RI	VT	ISO-NE Total
BAU Case Peak	MW	7,319	12,743	2,016	2,603	1,836	1,003	27,520
BAU Case load	GWh	33,300	60,838	11,550	12,392	8,050	5,994	132,124
Load Factor	%	52%	55%	65%	54%	50%	68%	55%
State-Specific DRIPE Cases								
PDR Increment	GWh	2,335	5,897	1,180	543	1,010	896	
PDR as % intrastate load	%	7.0%	9.7%	10.2%	4.4%	12.5%	14.9%	
PDR as % ISO-NE Total	%	1.8%	4.5%	0.9%	0.4%	0.8%	0.7%	
PDR Increment	MW	421	1077	184	97	179	132	
PDR load factor	%	63%	63%	73%	64%	64%	77%	

Using those increments, AESC 2015 found electric energy DRIPE effects from each state-specific DRIPE Case relative to the BAU Case over the first two and approximately one-half years of the study period (January 2016 through May 2018). Exhibit 7-3 presents the energy DRIPE coefficients for each state by season and pricing period.

Exhibit 7-3 State-Specific Energy DRIPE Coefficients

Average % Reduction in Electric Energy Prices, January 2015 through May 2018, for 1% Reduction in Intrastate Load

CT	Intrastate			Interstate - ROP		
	OnPeak	OffPeak	AllHours	OnPeak	OffPeak	AllHours
Summer	0.0620	0.2934	0.1050	0.0575	0.1577	0.0625
Winter	0.0989	0.1423	0.0852	0.0874	0.1269	0.0743
Annual	0.0881	0.1865	0.0910	0.0787	0.1359	0.0709

MA	Intrastate			Interstate - ROP		
	OnPeak	OffPeak	AllHours	OnPeak	OffPeak	AllHours
Summer	**0.7210**	0.3272	0.4511	0.6145	0.3006	0.4557
Winter	0.3067	0.1651	0.2241	0.2744	0.1692	0.2223
Annual	0.4280	0.2126	0.2905	0.3739	0.2077	0.2906

NH	Intrastate			Interstate - ROP		
	OnPeak	OffPeak	AllHours	OnPeak	OffPeak	AllHours
Summer	0.2432	-0.0008	0.1039	0.0936	-0.0001	0.0638
Winter	0.0499	0.0582	0.0671	0.0542	0.0596	0.0714
Annual	0.1065	0.0409	0.0779	0.0657	0.0421	0.0692

RI	Intrastate			Interstate - ROP		
	OnPeak	OffPeak	AllHours	OnPeak	OffPeak	AllHours
Summer	0.2462	0.0233	0.1367	0.1347	0.0131	0.0817
Winter	0.0365	0.0163	0.0311	0.0181	0.0147	0.0213
Annual	0.0978	0.0183	0.0620	0.0522	0.0142	0.0390

ME	Intrastate			Interstate - ROP		
	OnPeak	OffPeak	AllHours	OnPeak	OffPeak	AllHours
Summer	-0.0487	0.0233	-0.0103	-0.0581	0.0292	-0.0095
Winter	0.0559	0.0368	0.0469	0.0582	0.0397	0.0495
Annual	0.0252	0.0328	0.0302	0.0241	0.0366	0.0322

VT	Intrastate			Interstate - ROP		
	OnPeak	OffPeak	AllHours	OnPeak	OffPeak	AllHours
Summer	-0.0268	0.0306	0.0013	-0.0644	0.0174	-0.0146
Winter	0.0245	0.0217	0.0238	0.0219	0.0222	0.0226
Annual	0.0095	0.0243	0.0172	-0.0033	0.0208	0.0117

The negative results for a few seasonal periods in a few zones are consistent with actual experience, as indicated by a third of the days experiencing higher prices despite lower loads. Those results are explained by the impact of various factors in addition to unit commitment, including zone-specific transmission constraints on certain days and differences in PDR size and shape.

7.2.2 Impact of Supply Curve and Unit Commitment on Size of Energy DRIPE

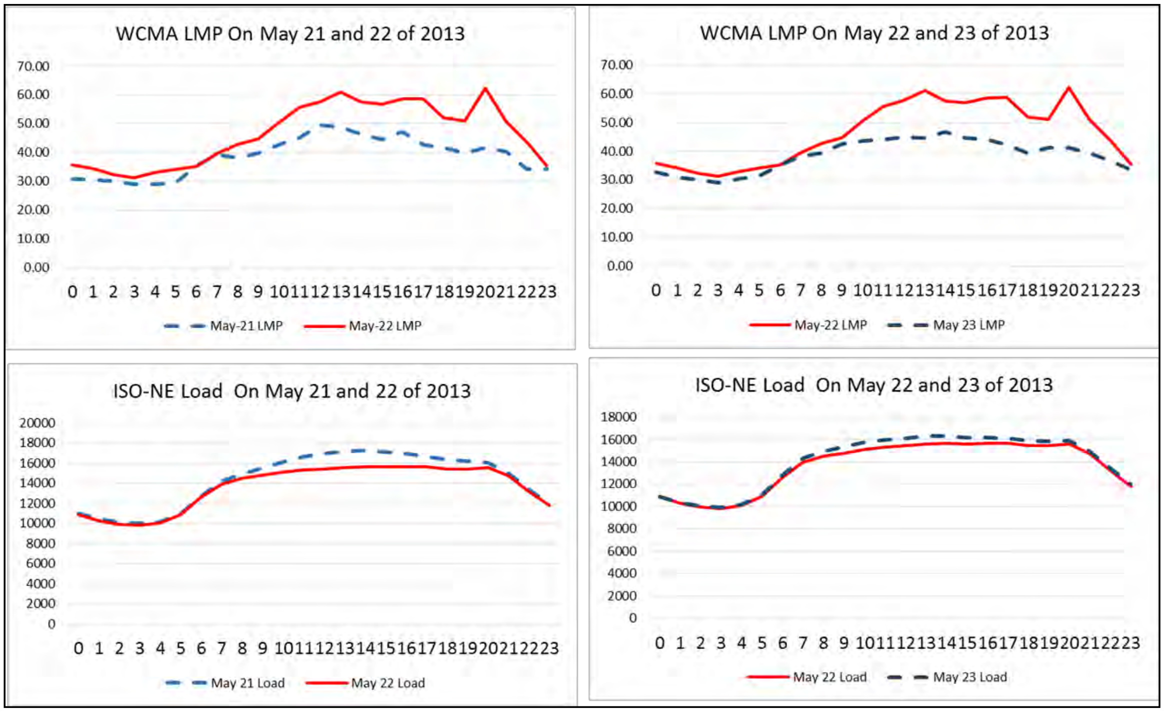
AESC 2015 projects the energy market prices under the BAU case and each state specific DRIPE case by simulating the formation of energy prices based on the energy supply curve and the ISO-NE unit commitment process. The formation of energy prices under those cases is largely driven by two main factors, the supply curve and unit commitment. As a result, the size of the energy DRIPE AESC 2015 is projecting is also largely driven by those two factors, both of which tend to dampen the size of energy DRIPE.

The supply curve dampens the energy DRIPE because the section which sets energy prices on most days is essentially flat, as described in Section 6.10. The unit commitment process dampens the energy DRIPE because ISO NE makes its decisions regarding which units to commit to serving load based on its projection of load for 24 hours, not for just 1 hour, as described in Chapter 5. Because of those two factors, there is not a simple linear relationship between the energy load in a given hour and the load in that hour. Instead, the relationship between energy prices and loads is affected by load on a given day, fuel prices on that day and unit availability on that day.

There will be days on which actual conditions will differ from the ISO NE forecast conditions due to market conditions that ISO-NE did not expect, e.g., an unexpected outage, oversupply or unexpectedly high or low demand. However, it is not clear that energy DRIPE effects would occur under those types of unexpected market conditions, i.e. when the market did not operate exactly as planned, i.e. “perfectly” or according to perfect foresight. We are not aware of specific examples of energy DRIPE impacts during days or hours when the energy market did not work “perfectly”. On the contrary, many factors can cause unexpected market conditions, and one would have to identify and analyze those factors in order to determine if lower load due to reductions from energy efficiency would have had any effect on prices under those conditions. In other words, to estimate the energy DRIPE effect of efficiency reductions on a day when actual conditions are materially different from forecast conditions, one must know the specific cause of the difference in prices between actual and forecast market conditions. It is also important to note that reduction in load from efficiency is a long-term, passive demand resource. As such, it is very different from a reduction in load from Active Demand Resources, which provide reductions only at the time of and only in response to unexpected market conditions.

To demonstrate the impact of unit commitment on energy prices we have assembled empirical evidence from 2013. To start, consider the following example based on actual New England loads and LMPs for three consecutive days: May 21, 22 and 23 of 2013 as shown in **Exhibit 7-4**.

Exhibit 7-4. Loads and LMPs for May 21, 22, 23 of 2013

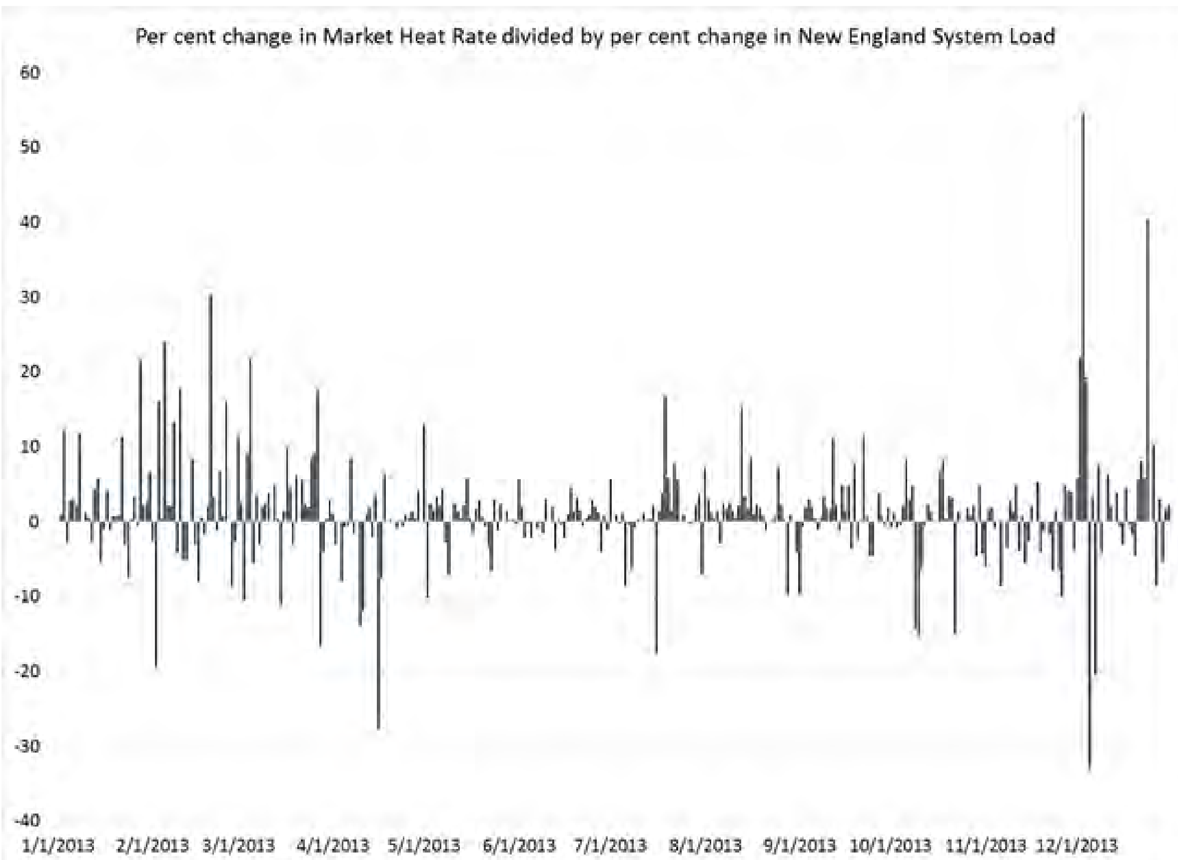


On all three days natural gas prices were close: \$4.47, \$4.64, and \$4.63 per MMBtu on May 21, 22 and 23, respectively. As one can see, load on May 22 was lower than on May 21 in every hour of the day. In fact, at 14:00 on May 22 load was 1,625 MW less than at 14:00 on May 21. In contrast, LMPs on May 22 were higher than on May 21. For example, at 20:00 on May 22 the price was \$20/MWh higher than at 20:00 on May 21 Similarly, load on May 23 increased from May 22 levels by as much as 682 MW (hours 12:00 and 13:00) but LMPs declined by as much as \$21/MWh at 20:00. The hourly energy prices corresponding to the hourly loads on these three days is not consistent with, and cannot be explained by, a single high-level supply curve.

That Exhibit provides a clear illustration of why a market simulation approach, one that reflects the unit commitment process and other market factors that drive the formation of energy prices each day, is required to develop an accurate estimate of energy DRIPE. The difference in load between May 21 and May 22 could be interpreted as a demand reduction on May 21 to the May 22 level. However, on that day, demand reduction would result in price increase. Similarly, demand reduction on May 23 to the May 22 level would again result in price increase.

Second, to estimate the frequency of these price effects we analyzed changes in average daily LMPs during 2013 relative to changes in daily loads. The goal of this analysis was to assess how often an increase in demand from one day to another would result in a decrease in the average daily LMPs, and vice versa. In other words, the frequency of changes in price moving in the opposite direction to changes in demand. Recognizing that load on a given day is not the only determinant of average prices for that day we controlled for differences in gas prices from day to day. We did this by computing the average market heat rate for each day, which is the ratio of the average LMP each day to the average spot price of gas on that day. Then we computed the ratio of the change in market heat rates from day to day to the change in daily load from day to day. (We removed outliers where small changes in load resulted in very large ratios). The results are plotted in Exhibit 7-5. Again, these actual results are not consistent with, and cannot be explained by, a single high-level supply curve.

Exhibit 7-5. Change in Average daily Market Heat Rate versus Change in average daily System Load



Finally, Exhibit 7-6 and Exhibit 7-7 further illustrate that many days in 2013 had the same or similar loads but a range of energy prices. These two figures plot daily on-peak period market heat rates versus daily on-peak loads from 2013 for the summer and winter seasons respectively. This actual data demonstrate that energy prices are not solely driven by load, they are affected by the unit commitment process, fuel prices and outages.

Exhibit 7-6

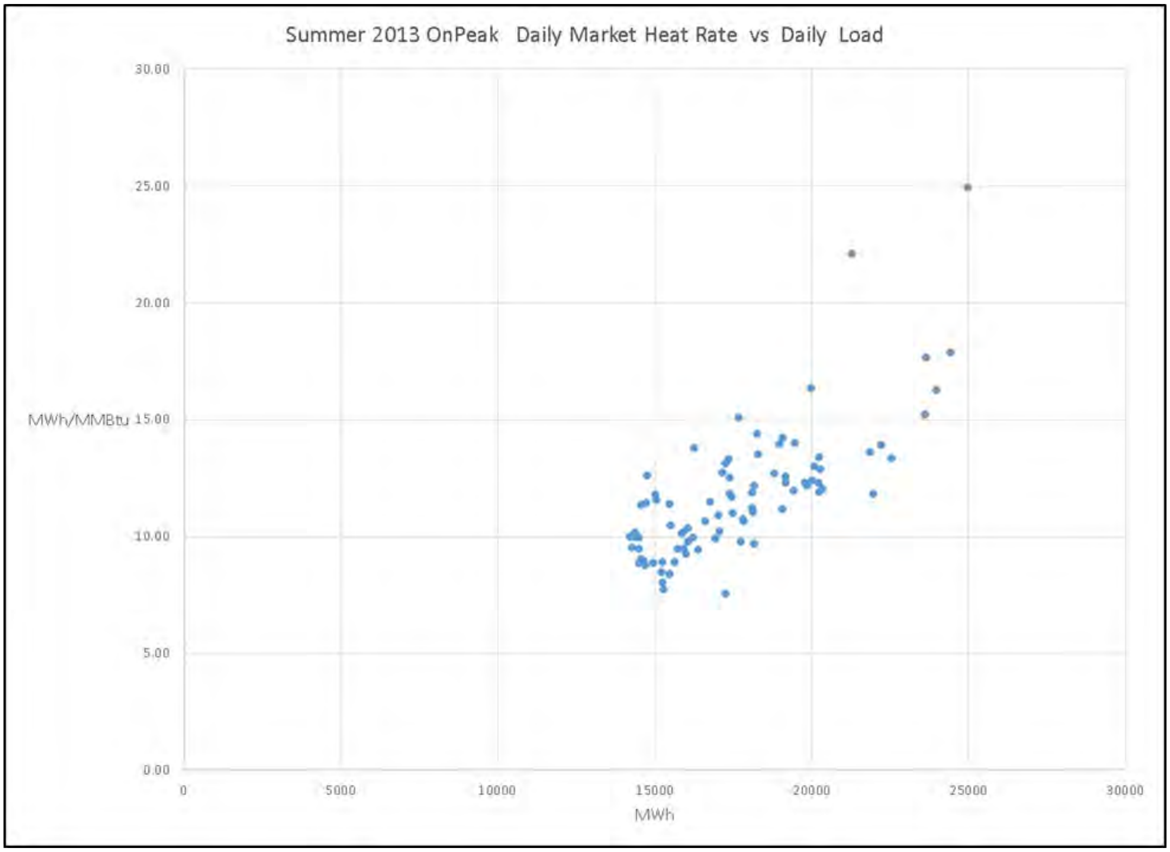
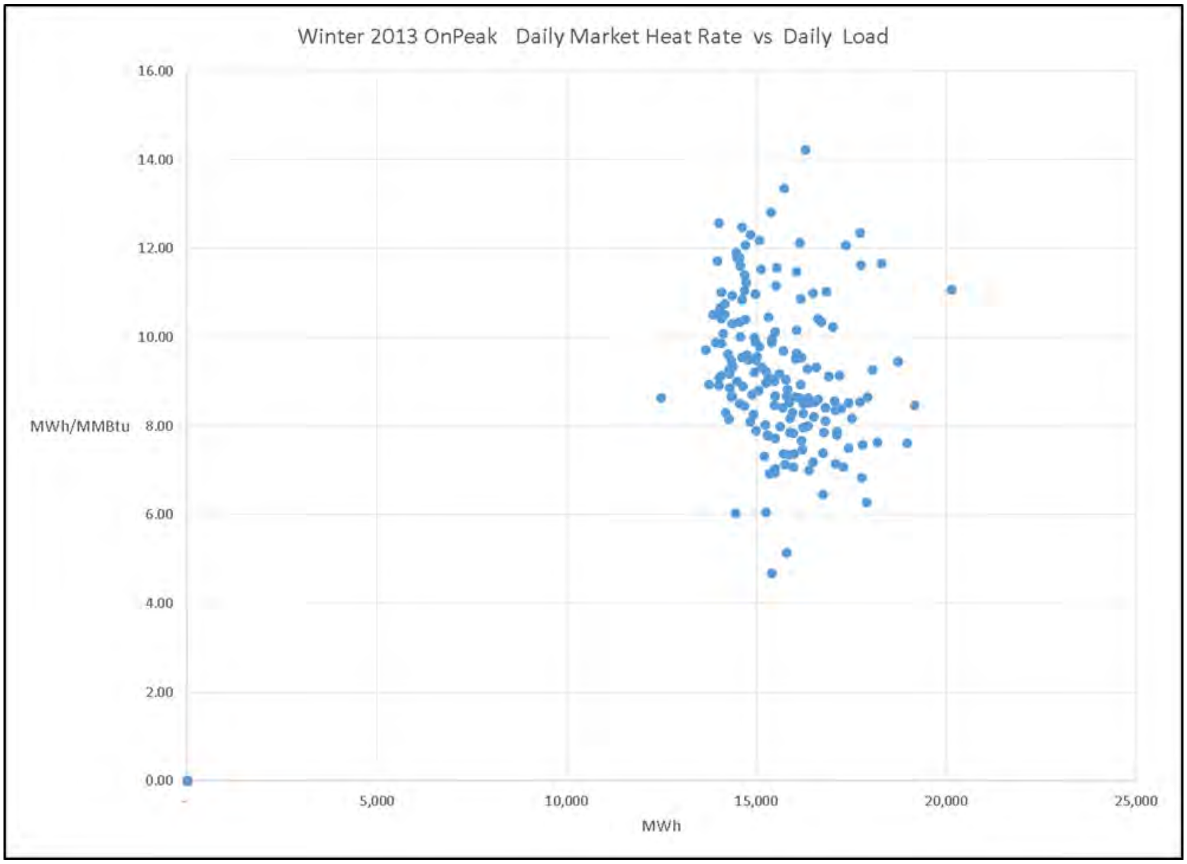

Summer 2013 OnPeak Daily Market Heat Rate vs Daily Load
MWh/MMBtu
30.00
25.00
20.00
15.00
10.00
5.00
0.00
0
5000
10000
15000
20000
25000
30000
MWh

Exhibit 7-7



7.2.3 Comparison with regression analysis of 2013 data

TCR prepared two different regression analyses of 2013 hourly prices and loads and compared them to the coefficients from its simulation modeling to compare against the AESC 2015 modeled DRIPE methodology. Exhibit 7-8 provides these comparisons for annual on-peak periods.

Row 1 of the Exhibit reports the projected energy DRIPE coefficients for 2015 to 2017 from the state-specific DRIPE Case. The coefficients represent the % change in average daily price in the state for the relevant period divided by the change in average daily load in the state as a % of ISO NE system wide load. (The coefficients are computed monthly and averaged across all months between January 2015 and May 2018). These coefficients measure change in price versus load in the period by day rather than by hour because the model simulates the operation of the market by ISO NE, which sets the prices each day through its unit commitment process. The on-peak energy DRIPE coefficients range from 0.33 to 1.4, The range in coefficients is attributable to the fact that the decrement in each state specific DRIPE Case occurs in a different state (i.e. location) and is of a different size and load shape. On a state load weighted basis, the resulting coefficient for New England is 0.7 which rounds to 1.

Row 2 of the Exhibit reports energy DRIPE coefficients in 2013 Cases from a TCR multi-regression analyses of 2013 actual average period prices by day versus actual period system-wide loads by day and fuel prices by day. (TCR did the regression for load and fuel price to control for variation in fuel prices from day to day.) The on-peak result is an energy DRIPE coefficient of 1.1, which also rounds to 1. These result are the same order of magnitude as the coefficients from the state-specific DRIPE Cases. (The regression has an R^2 of 0.83, which is not an explanatory variable, instead it is a measure of how well the regression model / formula explains variances in the dependent variable)

Row 3 of the Exhibit reports energy DRIPE coefficients in 2013 Cases from a TCR multi-regression analyses of 2013 actual hourly on-peak prices versus actual hourly on-peak system-wide loads and daily fuel prices. TCR did this regression for hourly prices and loads to demonstrate that the energy DRIPE coefficient will be less accurate, in this case, 1.3 instead of 1.1, because it does not reflect the impact of the unit commitment process on the formation of energy prices each day. (The AESC 2013 energy DRIPE coefficients, which are higher, are based upon a regression of hourly prices by period versus hourly loads by period from 2009 to 2012).

The results from the regression analysis of 2013 hourly prices and loads, presented in row 3 of Table 1, are less accurate than the regression analysis of 2013 hourly prices by day and loads by day, presented in row 2 of Table 1, because the row 3 regression does not reflect the impact of the daily unit commitment process.

The results from the regression analysis of 2013 hourly prices by day and loads by day, presented in row 2 of Table 1, to be less accurate than the coefficients from the simulation model because the simulation model reflects differences in impacts by state due to differences in size and shape of PDR.

Exhibit 7-8. Electric Energy DRIPE coefficients, peak periods, AESC 2015 simulation versus regression analyses of 2013 data

Electric energy DRIPE. % change in energy price for a % change in load relative to ISO NE load

Table 1. Annual On-Peak Period

Source	Data source / Time Period	Dependent Variable	Independent Variables	CT	MA	ME	NH	RI	VT	ISO NE (1)
state-specific DRIPE Cases	2015 - 2018	peak period energy prices by day in state	peak period load and fuel price by day in state	0.33	0.89	0.27	1.13	1.4	0.19	0.72
TCR regression analysis daily prices	2013	peak period energy prices by day at WCMA	peak period load and fuel price by day							1.10
TCR regression analysis hourly prices	2013	peak period energy prices by hour at WCMA	peak period load by hour and fuel price by day							1.30
Note	1	ISO NE result is a state load weighted average per 2015 annual loads								

7.2.4 Comparison with AESC 2013 estimated size of energy DRIPE effect

The AESC 2015 projections of energy DRIPE price effects are smaller than the AESC 2013 projections for peak periods, which ranged from 1.9 to 2.2[179]. The differences between the energy DRIPE estimates from the two studies is primarily attributable to a difference in analytical approach. AESC 2015 projections are developed directly by simulating the operation of the energy market under the BAU Case and under each of the state-specific Cases (i.e., CT, ME, MA, NH, RI, VT). The AESC 2015 simulation modelling reflects the impact of the ISO-NE daily unit commitment process as well as differences in impacts by state due to differences in size and shape of PDRs. The AESC 2013 regression analysis of hourly prices and loads from 2009 to 2012 provides a less accurate projection because it does not reflect that detailed level of market operation.

7.3 Wholesale Gas DRIPE

Reducing natural gas demand for electricity generation in a market area such as New England is, all else being equal, expected to reduce the quantity of gas supplied to that location. Classical economic theory suggests, in turn, that we may expect the price of natural gas at that location to fall in response to the reduction in gas requirements. The AESC 2015 RFP refers to this response as a gas demand reduction-induced price effect (herein, gas DRIPE).

This section presents the basic assumptions and methodology that underpin the AESC 2015 analysis of gas DRIPE, which consists of two components, production area price DRIPE and New England basis DRIPE.

Based upon our review of gas supply price elasticity (also referred to as the price elasticity of gas supply), we are assuming a production area supply price elasticity of 1.52 which indicates a percentage change of 1.52% in quantity for a 1% change in price. This implies an inverse price elasticity of 0.6579 (1/ 1.52) under which, for example, a 10% change in gas demand in the relevant production area would produce a 6.58% change in the price of gas production. The inverse supply price elasticity is used for the gas DRIPE analysis, i.e., the greater the supply elasticity, the less the DRIPE effect. The AESC 2015 estimate of production area gas DRIPE is approximately 23% less than the AESC 2013 estimate (i.e., $0.49/MMbtu for a 1 quad decrease in demand versus $0.632/MMBtu).

The AESC 2015 estimate of New England basis DRIPE in the three peak winter months is less than the AESC 2013 estimates, ranging from 50% less in the winter of 2014 to 80% less in the winter of 2019.

179 AESC 2013, page 7-8.

7.3.1 Supply Price Elasticity Methodology

Our gas DRIPE analysis is based on the identification and assessment of estimates of the price elasticity of gas supply acquired at two different locations, gas production areas and the New England market area. As such, it is worthwhile to begin by referring to a standard economics textbook definition of supply price elasticity. In her widely used energy economics textbook,[180] Carol Dahl defines supply elasticity this way: “The responsiveness of quantity supplied to a variable is called the elasticity of supply with respect to that variable.” (Dahl, 2004). Dahl then simplifies: “[Supply elasticity] is the percentage change in quantity divided by the percentage change in the variable. We can write the elasticity of supply [*Q*] with respect to price P as:

$$\varepsilon_s = \frac{\%\text{ change } Q_s}{\%\text{ change P}} = \frac{\frac{\Delta Q_s}{Q_s}}{\frac{\Delta P}{P}}.$$

Where delta represents a discrete change in the variable.” (Dahl 2004, p. 32)

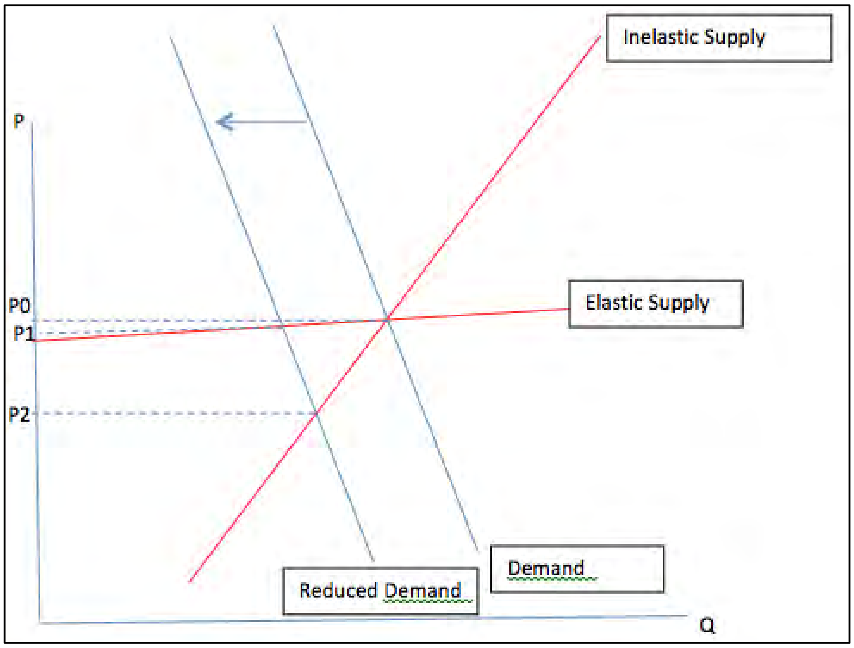
In the foregoing definition, the quantity (Q) and price (P) refer to the same commodity, in other words, “own price elasticity,” as opposed to a cross-elasticity. In effect, price elasticity of supply (herein, supply elasticity) is the % change in quantity supplied divided by the % change in supply price. This is distinct from the price elasticity of demand (demand elasticity), which characterizes quantity demanded at a price.

We take the elasticity of gas supply (in shorthand: gas supply elasticity), then, to be related to the slope of the price-quantity (P-Q) supply curve for gas at the relevant location. This kind of curve is illustrated in the diagram in Exhibit 7-9.

As in AESC 2013, we also assume the cause-effect relationship works both ways i.e., symmetrically. Thus, for example, if the P-Q supply curve is steep (the line labeled “Inelastic Supply” in Exhibit 7-9, supply elasticity is relatively low, so a given change in gas demand would produce a relatively large change in price i.e., a large gas DRIPE effect as P0 falls to P2. Conversely, if the P-Q supply curve is flat (the line labeled “Elastic Supply” in Exhibit 7-9), then supply elasticity is high, so a given change in gas demand would produce a relatively small change in price (i.e., P0 to P1, a small gas DRIPE effect). In the latter case, Elastic Supply, the gas DRIPE effect would be low because even a large decrease in demand would induce only a small price reduction.

[180] Carol A. Dahl, Professor Emeritus, Mineral and Energy Economics Program, Division of Economics and Business, Colorado School of Mines, “International Energy Markets: Understanding Pricing, Policies & Profits,” Pennwell Press, April 2004. Note this definition remains in Dahl’s revised edition, forthcoming in 2015.

Exhibit 7-9: Illustrative Supply Price-Quantity Curves



Thus, the analysis of gas DRIPE is actually a study of gas supply elasticity. Studying gas supply elasticity requires statistical analysis of a large number of relevant quantity and price data points in order to establish a P-Q supply curve. The data making up the P-Q gas supply curve must be accurate or the curve, and its elasticity at the point where the demand reduction takes place, will not be useful. In addition, the data must be able to "explain" the majority of a change in quantity as a function of change in price, or vice versa, otherwise the curves will not provide a reasonable estimate. For example, R2 is a generally accepted statistical test of the correlation of one set of data with another, i.e., to explain changes in the dependent variable as a function of changes in the independent variable. For example, sets of data with an R2 over 0.8 are considered to correlate well, while sets of data with an R2 of less than 0.4 are not considered to correlate. Thus, in the latter case of a 40% R2 correlation, variations in one data set cannot be used to explain variations in the other.

7.3.2 Production Area Price Gas DRIPE: Assumptions and Methodology

The 2013 AESC report considered a number of data sources, but ultimately developed production area price gas DRIPE based on a summary-level analysis involving comparisons of gas production quantities and Henry Hub prices from a number of AEO 2012 cases. The AESC 2015 team has also reviewed numerous estimates of production area gas supply elasticities. In light of the rapid changes taking place in the Northeast U.S. gas industry as a result of burgeoning Marcellus/Utica and other shale gas production, however, we have attempted to confine our focus on relatively recent estimates of supply curves and elasticities that hopefully reflect these dramatic changes.

Before reviewing this literature, it can be seen in plain terms that supply elasticity in rapidly growing shale fields like the Marcellus/Utica formation is obviously quite high, even to the point of being almost flat in the short-term time frame. In other words, the P-Q supply curve for the Marcellus/Utica shale basin is much like the flat curve marked "Elastic Supply" in Exhibit 7-9, so that even a large decrease in gas demand is unlikely to induce a downward price effect because local supplies already outstrip demand. In a business in which further drilling awaits further demand, and in which drilling productivity is rising dramatically in response to very low prices, there can be almost no gas DRIPE effect in the short term. Longer-term gas DRIPE is possible, of course, in the expectation that some kind of movement may take place toward the kind of supply-demand balance that would enable gas DRIPE to take place – i.e., gas DRIPE would be enabled because it would be set in a context of otherwise rising gas demand and, ultimately, gas production cost increases consistent with the beginnings of local resource depletion.

The frustrations of trying to develop supply elasticity in the unique economic environment we find ourselves in with respect to gas development for New England are only beginning to surface in the literature. A recent report by Resources for the Future (Mason et al 2014)[181] cites findings by Arora and others (Arora 2014)[182] that the supply based on shale production is more elastic than conventional sources. In looking at 2008-2012 data, Arora notes his data suggest, "…supply based on shale production is more elastic than conventional sources." (Arora 2014). Rice University professor Kenneth B. Medlock has been far more pointed: "The domestic supply curve is much more elastic as a result of shale gas developments. Domestic long run elasticity with shale = 1.52; without = 0.29."[183] Medlock, whose work relies on experientially derived field-by-field gas supply curves, is indicating findings that suggest earlier estimates of gas supply elasticity may be off by a factor of as much as five.

The difficulty in estimating supply elasticity with precision in a changing world (and with varying data sets) is illustrated in Exhibit 7-10, taken from Stanford University's Energy Modeling Forum (EMF) recent comparison of energy models.[184] The EMF results, and its past studies, show that different models are likely to produce a very wide range of estimates of supply elasticity, even if provided with similar macroeconomic, resource base, and other common assumptions.

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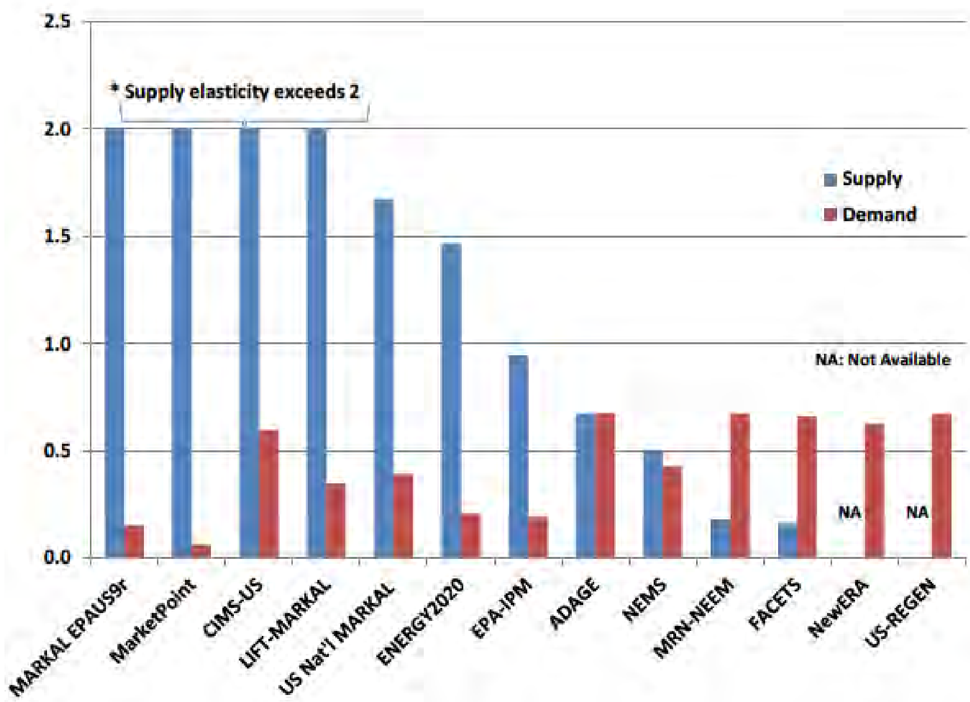
[181] Charles F. Mason, Lucija A. Muehlenbachs, and Sheila M. Olmstead, The Economics of Shale Gas Development, November 2014 (RFF DP 14-42), http://www.rff.org.

[182] Vipin Arora, Estimates of the Price Elasticities of Natural Gas Supply and Demand in the United States, March 2014, MPRA Paper No. 54232, http://mpra.ub.uni-muenchen.de/54232/

[183] Kenneth B Medlock III, PhD, Senior Director, Center for Energy Studies, James A. Baker, III, and Susan G. Baker Institute for Public Policy, Rice University ("Rice/Baker"), "Shale: Well Behavior, Demand Response and Exports," based on the BIPP Center for Energy Studies publications: "Panel Analysis of Barnett Shale Production"; "US LNG Exports: Truth and Consequence"; and SENR Testimony Feb 12, 2013, Rice/Baker Center for Energy Studies, April 15, 2013. Note the Rice/Baker analysis model is a generalized equilibrium model (i.e., much like separate supply-demand-price calculation models for each gas supply region) with continual supply-price information updates gleaned from shale and other unconventional drilling operations.

[184] Energy Modeling Forum, Stanford University, "Changing The Game? Emissions And Market Implications of New Natural Gas Supplies," EMF Report 26, Volume I, September 2013, page 24.

Exhibit 7-10: Inferred Price Elasticities for 2035 in 13 Forecasting Models



As a surrogate for precise field elasticities that are unavailable, therefore, we consider three separate approaches to estimate gas production area price DRIPE:

- Extracting gas supply elasticities implicit in a number of recent studies of the impacts of changes in gas demand caused by LNG exports.
- Following the methodology that underpinned calculations of gas production area price DRIPE in AESC 2013, i.e., inferring elasticities inherent in the NEMS model, as developed through analysis of different AEO 2014 cases.[185]
- Relying on the Rice/Baker modeling results.

Recent Assessments of the Impact of LNG Exports on Gas Prices

A number of analysis reports have been produced in the past several years describing the potential extent of US LNG exports and their domestic economic impact. AESC 2013 contained a useful review of

[185] It should be noted that AESC 2013 rejected a number of outdated elasticity estimates but, even so, events have moved quickly beyond the elasticity estimates it finally relied on.

the reports that were available at that time. We summarize below these and another, more recent EIA report, with respect to their implied gas supply elasticities:

***EIA, 2014*[186]**

In its update of earlier studies, the EIA states it reached these conclusions regarding domestic natural gas prices:

> Starting from the AEO2014 Reference case baseline, projected average natural gas prices in the Lower 48 states received by producers in the export scenarios are 4% (12-Bcf/d scenario) to 11% (20-Bcf/d scenario) more than their base projection over the 2015-40 period. Percentage changes in delivered natural gas prices, which include charges for gas transportation and distribution, are lower than percentage changes in producer prices, particularly for residential and commercial customers. Starting from the AEO2014 Reference case baseline, projected average Lower 48 states residential natural gas prices in the export scenarios are 2% (12-Bcf/d scenario) to 5% (20-Bcf/d scenario) above their base projection over the 2015-40 period. (EIA 2014)

The lower end of the range studied by EIA, 12 Bcf/day, represents about 16.25% of projected U.S. gas demand in the AEO 2014 Reference Case. Dividing the 16.25% increase in demand by the 4% increase in production area price (apart from costs of transportation and distribution) yields an estimated elasticity of 4.06, which implies that a 10% change in overall U.S. gas quantity would produce a 2.46% change in price.

***NERA, 2012*[187,188]**

The DOE-sanctioned study of U.S. domestic economic effects of LNG exports examined two scenarios in terms of export volumes – 6 Bcf/day and 12 Bcf/day (NERA 2012). Under sponsorship from Cheniere Energy, Inc., not the government, NERA prepared a follow-up of its report for the DOE (Baron et al 2014) that examined a large number of additional LNG export scenarios, ranging from 1 Bcf/day up to 19.5 Bcf/day. In each case, NERA based its forecasts in part on Annual Energy Outlook scenarios that were available at the time it prepared the studies, AEO 2012 in the case of NERA 2012 and AEO 2013 in the case of its follow-up report (Baron, et al 2014).

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[186] EIA, Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets, October 2014, http://www.eia.gov/analysis/requests/fe/

[187] National Economic Research Associates (NERA), Macroeconomic Impacts of LNG Exports from the United States, December 2012, http://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

[188] Robert Baron, Dr. Paul Bernstein, Dr. W. David Montgomery, and Dr. Sugandha D. Tuladhar, Updated Macroeconomic Impacts of LNG Exports from the United States," NERA, February 2014. http://www.nera.com/publications/archive/2014/updated-macroeconomic-impacts-of-lng-exports-from-the-united-sta.html.

NERA's more recent report assumes the natural gas resource supply elasticity varies with the U.S. natural gas supply scenario. In the study's reference scenario, the elasticity of supply for North American natural gas begins at 0.3 in 2018 and increases to 0.68 by 2038." (Baron, 2014, p. 159). We note these estimates were grounded in EIA/NEMS model runs that have since been updated. In other words, since AEO 2014 has long since replaced AEO 2013, and EIA's efforts toward AEO 2015 are well underway, the reasonable course here would be to examine updated AEO cases for this purpose, see the following subsection.

***Deloitte MarketPoint, 2012*[189]**

Deloitte's analytic group issued two successive analysis reports, in November 2011 and November 2012. Both projecting the effects of exporting 6 Bcf/d of LNG, mainly from the US Gulf Coast. Deloitte's MarketPoint group licenses and includes authors of the most widely regarded natural gas analysis methodology, the World Gas Trade Model (WGTM), which was developed out of the North American Regional Gas Model (NARG). In the November 2012 study, Deloitte projected LNG exportation of 6 Bcf/day would cause a producer price increase of about $0.22/MMBtu, on average, in 2020-2030. This estimate represents an average 3.86% change in price from 2020 to 2030[190] and the 6 Bcf/day assumed by Deloitte represents an 8.13% change in quantity, as above. Hence, Deloitte's result implies a supply elasticity of 2.11, i.e., a 10% change in quantity would produce a 4.74% change in price.

Other LNG Export Impact Studies

Results of the foregoing studies are corroborated by a number of other reports, including those issued by:

- Brookings Institution – a compendium and critique of all US LNG export studies issued up to its publication in May 2012, entitled "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas." The Brookings report, which was assembled by a panel consisting of the authors of each major study and other gas industry experts, is a useful review of the issues that each study is attempting to address, and a summary of their collective results from a policy perspective. This report concludes that macroeconomic effects of LNG exports would greatly outweigh effects on domestic gas consumers.

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[189] Deloitte Center for Energy Solutions and Deloitte MarketPoint LLC, Exporting the American Renaissance Global impacts of LNG exports from the United States, November 2012, https://www2.deloitte.com/content/dam/Deloitte/global/Documents/dttl-er-exportingamericanrenaissance-08072013.pdf.

[190] Deloitte's gas price projection is shown in Exhibit 1-8.

- Rice/Baker – an analysis using the same generalized equilibrium model discussed above (and below) of the likely global effects of US LNG exportation, and likely volumes.[191] Rice/Baker's World Gas Model (WGM) employs essentially the same methodology as the Deloitte WGTM, with some differences in data and assumptions. In particular, Deloitte's version of the same basic model incorporates a large number of foreign contractual realities (as constraints); the Rice/Baker model generally does not embody such constraints and provides, therefore, an assessment of purely economic effects.[192] Rice/Baker's analysis concludes that US gas consumers will experience virtually no increase in retail gas prices due to LNG exports and that only minor volumes (about 2 Bcf/d) of US LNG will be exported because other world gas suppliers will out-compete the US.
- Council on Foreign Relations – a special report that critiques existing studies. This influential report provides a review of more in-depth studies it considers to be the best information available, and concludes that LNG exports are in the nation's economic and strategic interest.

In summary, the crop of LNG export impact studies conducted in the past several years provides an important, although mixed, source of information about gas supply elasticity for the gas production area price DRIPE study.

AEO 2014 Low Economic Growth Case versus AEO Reference Case

Following along lines of the methodology employed to calculate gas DRIPE in the AESC 2013 report, we estimated gas supply elasticities implicit in the NEMS model, as gleaned from a comparison of AEO 2014 cases.[193] AESC 2013 compared a large number of AEO 2012 cases to assess elasticities, and based its conclusions on that part of its review. Instead, AESC 2015 makes only a single comparison, namely, that most directly related to a gas demand reduction in isolation of other factors. In effect, this method tries to identify gas supply elasticities inherent in the NEMS model – not really different from the methodology in the AESC 2013 report, but simpler, again, with the realization that the pace of ongoing change has been so great in the Marcellus/Utica shale fields, that use of AEO's models represents a

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191 Reported in Kenneth B. Medlock III, "U.S. LNG Exports: Truth or Consequence," Rice/Baker, August 10, 2012.

192 Unlike in the U.S., long-term take-or-pay gas sales and purchase contracts (SPAs) dominate commerce in most other gas industries, including pipeline gas and LNG markets. In the U.S., Canada and the UK, however, gas is traded fluidly in short term or spot arrangements; even where long-term SPAs exist, they take pricing signals from spot gas indices. Consequently, differences between the Deloitte and Baker/Rice models with respect to treatment of SPAs are confined to gas markets outside the U.S., as these kinds of constraints would not be relevant in the U.S, including in the Marcellus/Utica region.

193 Note, this step is problematic because the NEMS model specifically eschews the use of price-quantity supply curves (thus supply elasticities) in its methodology and, instead, bases its analysis on the extant mix of drilling opportunities known at the time. In other words, EIA recognizes that the real world of gas well drilling actually does not follow a smooth, least-cost-first sequence of activities, thus efforts to impute elasticities inherent in NEMS are somewhat artificial.

snapshot for comparison purposes, and cannot be held out as comprehensive. In addition, we do so despite the caution in the preceding footnote.

In Exhibit 7-11, we find the foregoing discussion demonstrated vividly. Implied short-term elasticity is 10.42), mainly because demand evolves only gradually in the low economic growth case. In contrast, long-term elasticity changes drastically to 1.05 as the impact of reductions in demand are reflected in lower Henry Hub prices.

Exhibit 7-11: Gas Production Area Price Elasticities Implied in AEO 2014 Reference and Low Economic Growth Cases

	AEO 2014 Reference Case	AEO 2014 Low Economic Growth Case	Diff - Change in Sensitivity Case	Implied Elasticity
2015-2020				
Total Consumption/year	26.389	26.012	1.427%	
Average Lower 48 Price	4.354	4.348	0.137%	10.42
2020-2030				
Total Consumption/year	28.452	26.946	5.295%	
Average Lower 48 Price	5.305	5.037	5.061%	1.05

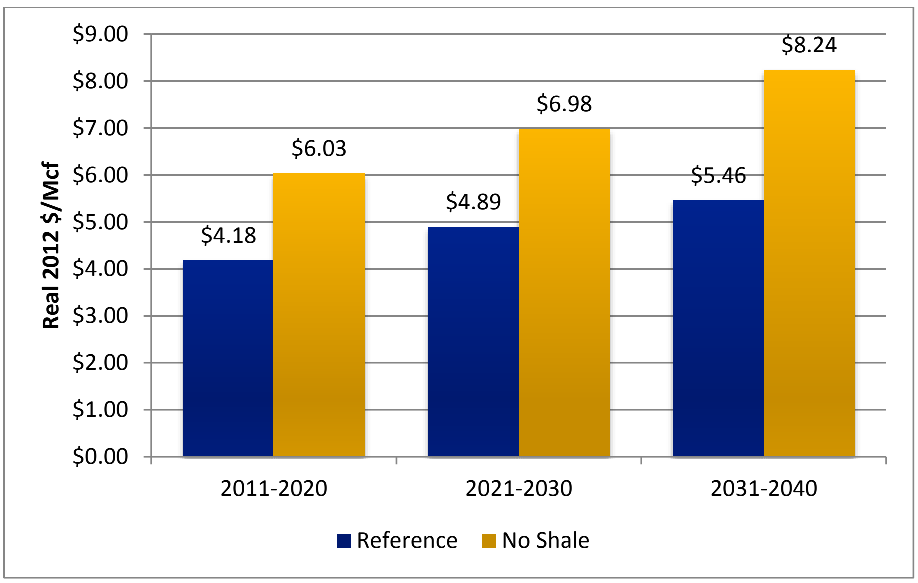
The foregoing analysis continues to have the difficulty plaguing other studies described above, namely, that the NEMS model was only gradually assimilating shale field realities and growth during mid-2013, when EIA was preparing AEO 2014. This concern may explain the rather low 2020-2030 estimate of elasticity we glean from this comparison.

Rice/Baker Studies

As discussed above, focusing specifically on the impact of shale gas, the Rice/Baker team makes use of its World Gas Trade Model, which is essentially the same model methodology employed by the Deloitte MarketPoint team. The Rice/Baker estimates of far greater gas supply price elasticity with shale versus without shale gas, i.e., 1.52 with shale nationally, versus 0.29 without shale – are derived from detailed assessment of field-level economics and emerging rig productivity (Medlock, 2013). EIA's process for reporting drilling productivity grew in part out of this pioneering work. Gas supply price-quantity curves (and, therefore, elasticities) form an inherent component of the Rice/Baker model. Such curves are derived by gleaning information from experienced geologists, field operators, and available local area data. Consequently, the Rice/Baker model comprehends a large number of disaggregated gas supply curves, some field by field. This fine-grained approach facilitates a shale-versus-no-shale analysis by adjusting supply curves for some regions to eliminate the influence of shale gas resources, or removing shale-only curves from the model altogether, depending on the locale. As an illustration, the gas supply curve for Pennsylvania would either include recoverable shale resources of, say, 400 Tcf or it would not, thus leaving only, say, 20 Tcf of recoverable resources. These and other (although not as pronounced) differences in gas supply curves for other locations were developed and incorporated into the Rice/Baker model. Building up regions to the nation as a whole, the Rice/Baker model was used to develop overall elasticities for with-versus-without shale gas scenarios, for the nation as a while. Along with aggregated elasticity measurements, the model results include Henry Hub and regional gas prices at more than 200 locations (hubs, pricing points, and the like), pipeline flows over time, sector-by-sector gas consumption in each of more than a dozen gas demand regions, pipeline gas and LNG imports and exports, and other information consistent with the scenario being examined.

The implications of the Rice/Baker analysis of the impact of shale gas production on Henry Hub prices are shown in Exhibit 7-12. These results illustrate the cost savings to U.S consumers inherent in the shale gas revolution, provided they have access to sufficient pipeline capacity.

Exhibit 7-12: Rice/Baker Estimate of Shale Gas Impact on Projected Henry Hub Prices



AESC 2015 Production Area Gas DRIPE - Conclusions

Based upon our review of the foregoing estimates and our own experience, the TCR team is proposing a production area supply price elasticity of 1.52, drawn from the Rice/Baker studies. That elasticity reflects the impact of Marcellus/Utica shale production, which has a relatively high production area price elasticity that is reasonably expected to last throughout most of the planning horizon. A production area supply price elasticity of 1.52 implies an inverse elasticity of 0.6579 (1/ 1.52) under which a 10% change in gas demand would produce a 6.58% change in the price of gas production. We note that Deloitte MarketPoint and a number of other model-based comprehensive studies (see Exhibit 7-10) produce higher estimates of elasticity than the one used by AESC 2015, thus we deem the 1.52 elasticity as a conservative estimate.

The following example places this elasticity in a New England perspective. If gas fired power plants throughout New England were to reduce gas demand by 100,000 MMBtu/day evenly during the study period (i.e. 0.1 Bcf/day) and if Marcellus/Utica gas production were to remain at 18.4 Bcf/day, the demand reduction would be 0.1 / 18.4 = 0.005435, or about 0.54%.[194] Applying the production area elasticity of 1.52 to that reduction in demand implies that Henry Hub gas prices would decline by 0.54% / 1.52 or about 0.3576%. Applying that decline to the AESC 2015 15 year levelized Henry Hub price of $4.99 per MMBtu (2015$) produces a production area price gas DRIPE effect of $0.0178 per MMBtu ($4.99 * 0.3576%).

The AESC 2015 production area price gas DRIPE is calculated and expressed in a different manner than the AESC 2013 estimate. The AESC 2013 estimate was a "$0.632/MMBtu decrease in Henry Hub gas price for every quad (quadrillion Btu or 10^9 MMBtu) decrease in annual gas consumption."[195] A one quad per year decrease in annual gas consumption is 27.4 times greater than the 100,000 MMBtu/day gas demand reduction example discussed above. Hence, to provide a production area gas DRIPE comparable to a 1 quad decrease in gas demand we multiply the AESC 2015 production area price gas DRIPE estimate of $0.0178 per MMBtu by 27.4 to get an impact of = $0.49/MMBtu for a 1 quad decrease in gas demand. Thus, the AESC 2015 estimate of production area gas DRIPE is approximately 23% less than the AESC 2013 estimate (i.e., 0.49/MMbtu versus 0.63/MMBtu).

7.3.3 New England Basis Gas DRIPE: Assumptions and Methodology

The second component of gas DRIPE is New England basis DRIPE. Much like natural gas, crude oil or agricultural products, some basis differentials are, themselves, commodities that may be traded fluidly in spot and commodity futures markets. Algonquin Citygate basis qualifies in that respect, i.e., Algonquin Citygate basis futures are actively traded on both the New York Mercantile Exchange (NYMEX) and the Inter-Continental Exchange (ICE), the latter with substantial front-month liquidity. As described earlier (see Chapter 2), Algonquin Citygate basis market on ICE (referred to as "ALQ") is a commodity that represents the difference between the wholesale Algonquin Citygate spot gas price and the corresponding price of gas at Henry Hub.

AESC 2013 estimated New England basis using the results of a correlation of daily pipeline nomination quantities and daily basis between Algonquin city-gates and TETCO M-3[196]. The correlation has an R^2 of

[194] Relatively close pricing and correlations among pricing points that lie purely within the supply region per se – Dominion Appalachia and Transco Leidy – suggests that natural gas moves about within the supply region from lower priced points to higher priced points, thus we cannot limit the supply field (the denominator) to volumes on one or another pipeline or within a particular sub-region, especially in a 15-year planning horizon.

[195] _____, AESC 2013, page 7-21.

[196] Ibid. Exhibit 7-21.

0.3525, which indicates that changes in daily nomination quantities do not correlate with changes in daily basis in the manner the regression model implies.

We considered estimating New England basis gas DRIPE from data on Algonquin Citygate basis, in a manner similar to AESC 2013. However, we determined that approach would not provide a reasonable estimate of New England basis gas DRIPE for two main reasons.

First, the attribution of gas basis DRIPE to gas efficiency measures assumes that LDCs will respond to reductions in retail gas use by existing retail customers by releasing temporarily spare pipeline capacity to allow deliveries of gas to gas-fired electric generators. The ASESC 2015 team do not consider this a reasonable assumption other than in the very short term. It is much more likely that LDCs in New England will want to use any pipeline capacity not required to supply existing customers to serve prospective new customers who wish to convert to gas from their existing fuel.

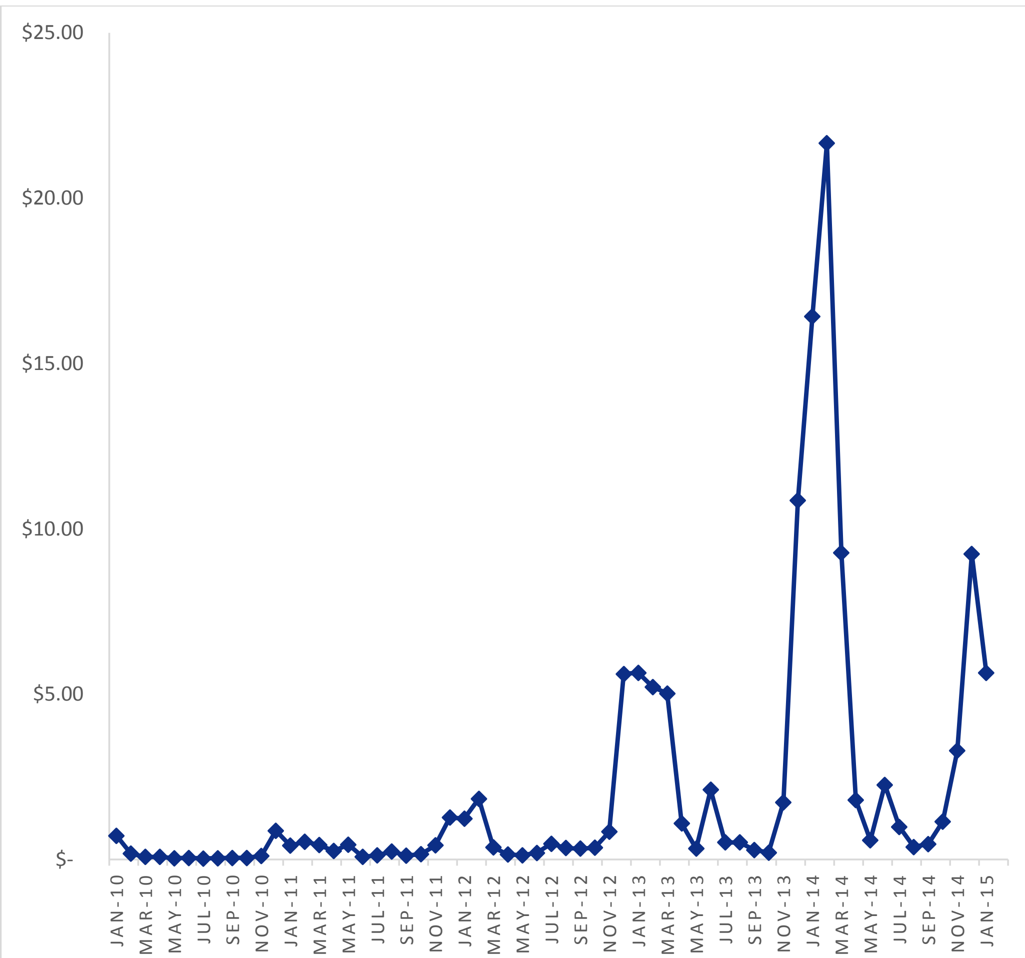
Second, numerous factors drive New England basis, whether referenced to Henry Hub or a Marcellus/Utica gas price index, making it extremely complicated to estimate. Basis on a given day is equal to the value of the marginal source of gas on that day minus the price of gas in the relevant supply region, which is the Henry Hub in this part of our analysis. During winter months the value of the marginal source of gas on a given day will be influenced by:

- The maximum price that marginal generating units are willing to pay for fuel that day. That value will in turn be driven by the market price of electricity expected for the day, the heat rates of their units, their ability to burn a fuel, low sulfur diesel, other than natural gas and the penalty, if any, they face for not generating.
- The price of low sulfur diesel
- The price of the marginal source of gas, which on peak days may be from LNG. (LNG is priced in global gas market competition, its price does not relate to New England so much as to other bidders that may be entirely reliant on its supply, e.g., Japan, South Korea, Taiwan and Spain are largely reliant on global LNG markets, and <u>their</u> alternate fuel is often gas priced to an index of costly liquid fuels.)
- The quantity of gas available from ALG & TGP
- The quantity of gas available from M&NP

Hence, efforts to correlate basis with one pipeline's nominations are problematic. Basis on any day is being driven by numerous factors in addition to pipeline nomination quantities. A correlation of basis with pipeline nomination quantities during winter months especially does not accurately reflect the impacts of these additional factors.

In addition, New England winter gas market conditions have changed dramatically beginning with the winter of 2012/2013, even before the "polar vortex." Falling gas prices in the Marcellus/Utica region coupled with declines in deliveries on M&NP, and costly LNG imports, have all led to dramatic increases in basis in the peak months of December, January and February. For example, Exhibit 7-13 shows how radically winter New England basis has changed since the AESC 2013 and a somewhat earlier study by Concentric[197] (Concentric 2012) were prepared. Not only were the correlations between Algonquin Basis and pipeline nominations presented in those reports clouded by the additional factors discussed above, particularly LNG, but they were prepared before there was a general recognition of the dramatic changes underway in New England winter gas markets. Neither study, however diligent they were, may be used as a foundation to estimate elasticities in the pipeline capacity-starved New England basis markets as we know them now.

Exhibit 7-13: Monthly Index Basis Differential between Algonquin Citygates and Tetco M-3, $/MMBtu



[197] Concentric Energy Advisors, "New England Cost Savings Associated with New Natural Gas Supply and Infrastructure," May 2012.

Consequently, we are proposing a relatively high-level generalized estimate New England basis DRIPE. Using a broad brush, we apply the same basic math described above in order to estimate production area gas DRIPE. Here, instead of referencing supply elasticities with respect to the Marcellus/Utica region's production of 18.4 Bcf/day, we consider the pipeline capacity available to deliver gas into the region from producing areas west of New England, particularly the Marcellus/Utica fields. As developed in Exhibit 4-5 of AESC 2015 Task 3A report, that existing Delivery Capacity equals 2.6 Bcf/day. Using our earlier example: a gas demand reduction of 100,000 MMcf/day (0.1 Bcf/day) amounts to a change of 0.10/2.6= 3.8%. We further assuming basis is highly inelastic in the winter months due to the limited quantity of capacity to deliver gas from the west, for a winter basis elasticity of 1:1, and highly elastic in the summer for a zero impact. The 0.1 Bcf/day reduction in demand in winter would produce a 3.8% reduction in winter month basis. AESC 2015 New England basis DRIPE is less than the 2013 estimates, as shown below.

Exhibit 7-14. Estimate of New England basis DRIPE

Estimate of New England basis DRIPE											
Month	Pipeline Capacity able to deliver Marcellus gas into western New England	Reduction in wholesale gas Use	% change	Basis Elasticity	New England basis to HH	Change in New England basis	Three Peak winter Months (D, J, F)			AESC 2013	Aesc 2015 vs AESC 2013
	bcf/Day	bcf/day			$/MMBtu	$/Mmbtu	coefficients			Exhibit 7-23	CHANGE - higher (lower)
							$/MMbtu reduction per reduction of				
							0.1 bcf/day	MMcf/day			
	a	b	c = b / a	d	e	f = e * c * d	g = avg DEC, Jan, Feb	h = g / 100		i	j = h / I - 1
December-13	2.6	0.1	3.8%	1	$ 11.36	$ 0.44					
January-14	2.6	0.1	3.8%	1	$ 17.65	$ 0.68	0.7566	0.00757		0.016	-53%
February-14	2.6	0.1	3.8%	1	$ 30.00	$ 1.15					
December-14	2.6	0.1	3.8%	1	$ 9.75	$ 0.38					
January-15	2.6	0.1	3.8%	1	$ 12.16	$ 0.47	0.4386	0.00439		0.0118	-63%
February-15	2.6	0.1	3.8%	1	$ 12.30	$ 0.47					
December-15	2.8	0.1	3.6%	1	$ 8.55	$ 0.31					
January-16	2.8	0.1	3.6%	1	$ 11.95	$ 0.43	0.3787	0.00379		0.0106	-64%
February-16	2.8	0.1	3.6%	1	$ 11.31	$ 0.40					
December-16	2.8	0.1	3.6%	1	$ 4.47	$ 0.16					
January-17	2.8	0.1	3.6%	1	$ 8.16	$ 0.29	0.2176	0.00218		0.004	-46%
February-17	2.8	0.1	3.6%	1	$ 5.64	$ 0.20					
December-17	3.2	0.1	3.1%	1	$ 4.39	$ 0.14					
January-18	3.2	0.1	3.1%	1	$ 2.50	$ 0.08	0.0953	0.00095		0.003	-68%
February-18	3.2	0.1	3.1%	1	$ 2.25	$ 0.07					
December-18	3.8	0.1	2.6%	1	$ 1.83	$ 0.05					
January-19	3.8	0.1	2.6%	1	$ 2.45	$ 0.06	0.0570	0.00057		0.003	-81%
February-19	3.8	0.1	2.6%	1	$ 2.21	$ 0.06					

7.4 Direct DRIPE Effects from Electric Efficiency

Section 7.2 provides estimates of the effect of reductions in electric energy use from energy efficiency programs on wholesale market prices for energy through May 2018. This section calculates the impact of those DRIPE effects on the retail rates of electric customers by year.

Electric energy DRIPE affects wholesale energy market prices immediately. Prior AESC studies have assumed that those wholesale energy price effects do not flow through to all retail electric customers immediately because most energy purchased for retail load is bought at prices set several months in advance of delivery. While that assumption is correct, it is reasonable to assume that the prices that are set several months in advance are based upon and /or tied to a projection of market prices for the period during which the electricity would be used. Moreover, the exact details of those contract quantities and prices are confidential. For those reasons, and because AESC 2015 is calculating energy DRIPE effects relative to a BAU Case, which is a realistic projection of market prices, we do not reduce the forecast load subject to wholesale energy market prices in each year by assumed levels of hedging.

Exhibit 7-15 presents the energy DRIPE effects by year by state.

Exhibit 7-15. Energy own-price DRIPE effects by year by state

Winter On-Peak						
Intrastate						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
2016	$ 6.60	$ 20.45	$ 3.72	$ 3.33	$ 2.43	$ 1.63
2017	$ 6.31	$ 19.57	$ 3.56	$ 3.18	$ 2.33	$ 1.56
2018	$ 3.34	$ 10.35	$ 1.89	$ 1.68	$ 1.23	$ 0.83
Rest-of Pool						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
2016	$ 5.83	$ 18.30	$ 3.88	$ 3.61	$ 1.21	$ 1.46
2017	$ 5.58	$ 17.51	$ 3.71	$ 3.46	$ 1.16	$ 1.40
2018	$ 2.95	$ 9.26	$ 1.96	$ 1.83	$ 0.61	$ 0.74

Summer On-Peak						
Intrastate						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
2016	$ 2.94	$ 34.19	$ (2.31)	$ 11.53	$ 11.67	$ (1.27)
2017	$ 3.03	$ 35.28	$ (2.38)	$ 11.90	$ 12.05	$ (1.31)
Rest-of Pool						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
2016	$ 2.73	$ 29.14	$ (2.75)	$ 4.44	$ 6.39	$ (3.05)
2017	$ 2.82	$ 30.07	$ (2.84)	$ 4.58	$ 6.59	$ (3.15)

Winter Off-Peak						
Intrastate						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
2016	**$ 8.79**	**$ 10.20**	**$ 2.27**	**$ 3.59**	**$ 1.01**	**$ 1.34**
2017	**$ 8.40**	**$ 9.75**	**$ 2.17**	**$ 3.44**	**$ 0.96**	**$ 1.28**
2018	**$ 4.39**	**$ 5.09**	**$ 1.13**	**$ 1.79**	**$ 0.50**	**$ 0.67**
Rest-of Pool						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
2016	**$ 7.84**	**$ 10.45**	**$ 2.45**	**$ 3.68**	**$ 0.91**	**$ 1.37**
2017	**$ 7.49**	**$ 9.99**	**$ 2.35**	**$ 3.52**	**$ 0.87**	**$ 1.31**
2018	**$ 3.91**	**$ 5.22**	**$ 1.22**	**$ 1.84**	**$ 0.45**	**$ 0.68**

Summer Off-Peak						
Intrastate						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
2016	**$ 9.03**	**$ 10.08**	**$ 0.72**	**$ (0.02)**	**$ 0.72**	**$ 0.94**
2017	**$ 10.70**	**$ 11.93**	**$ 0.85**	**$ (0.03)**	**$ 0.85**	**$ 1.12**
Rest-of Pool						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
2016	**$ 4.86**	**$ 9.26**	**$ 0.90**	**$ (0.00)**	**$ 0.40**	**$ 0.54**
2017	**$ 5.75**	**$ 10.96**	**$ 1.06**	**$ (0.00)**	**$ 0.48**	**$ 0.64**

7.5 Gas DRIPE and Electric Fuel-Related DRIPE Assumptions and Methodology

This section describes the major assumptions and methods AESC 2015 used to calculate natural gas efficiency direct and cross-fuel DRIPE as well as electric efficiency fuel-related and cross-fuel DRIPE.

Exhibit 7-16 provides an overview of our calculations of these three categories of DRIPE.

Exhibit 7-16. Summary of Gas-Related DRIPE Effects

Efficiency Programs	Value of Usage Reduction	Wholesale Gas Cost Component	Avoided Cost Calculation
Gas	Avoided Cost to retail gas consumers	Supply	Supply price DRIPE * retail gas use subject to wholesale gas supply price
		Pipeline transportation and Storage services	No impact
	Cross-fuel : Avoided Cost to retail electric consumers via reduction in fuel cost to gas-fired electric generation	Supply	Price DRIPE * retail electric use subject to wholesale electric energy market price
		Basis	Price DRIPE * retail electric use subject to wholesale electric energy market price
Electricity	Avoided Cost to retail electric consumers via reduction in fuel cost to gas-fired electric generation	Supply	Price DRIPE * retail electric use subject to wholesale electric energy market price
		Basis	Price DRIPE * retail electric use subject to wholesale electric energy market price
	Cross-Fuel : Avoided Cost to retail gas consumers via reduction in gas supply cost	Supply	Supply price DRIPE * retail gas use subject to supply price
		Pipeline transportation and Storage services	No impact

7.5.1 DRIPE Value of Reduction in Retail Gas Use – Assumptions and Method

The gas supply DRIPE effect of reductions in retail gas use is:

- the quantity of retail gas saved (MMBtu), multiplied by
- the gas supply DRIPE from Chapter 6 of \$0.49 × 10^{-9}/MMBtu per MMBTU saved, multiplied by
- the quantity of retail gas use (MMBtu) paying a price tied to the wholesale supply price. (AESC 2015 assumes this to be 100 per cent since the details of gas utility hedging arrangements, to the extent they exist, are confidential).

As in AESC we do not calculate a basis DRIPE because only a very small portion of gas delivered to retail gas users in New England is subject to market basis the reduction in retail gas use.

Cross-Fuel

The avoided cost to retail electric consumers from reductions in retail gas use results from the impact of savings from gas efficiency on the fuel cost of gas-fired electric generation. The reductions in retail gas use result in both gas supply DRIPE, (\$0.49 × 10^{-9}/MMBtu per MMBTU saved) and gas basis DRIPE. Those two sources of DRIPE result in a lower price for wholesale gas in New England, i.e. the fuel cost of gas-fired electric generating units. Those lower wholesale gas prices will, in turn, tend to reduce wholesale electric energy prices by reducing the production costs of gas-fired units. While generators are free to set their bid prices, the optimal bidding strategy for a gas fired generator that may set the market price is to bid an electric energy price close to its fuel price multiplied by its heat rate.

The cross-fuel gas supply DRIPE effect of reductions in retail gas use is:

- the quantity of retail gas saved (MMBtu), multiplied by
- the gas supply DRIPE from Chapter 6 of $\$0.49 \times 10^{-9}$/MMBtu per MMBTU saved, multiplied by
- the MMBtu required to produce a MWh of electricity. This is 7.2 MMBtu/MWh based on gas units setting the marginal energy price (directly or indirectly) in 85 percent of hours at an annual average heat rate of 8,500 Btu/kWh (i.e. 7.2 MMBTU/MWh = 8.5 MMBtu/MWh $\times$ 0.85), multiplied by
- the quantity of retail electric use (MWh) subject to wholesale energy prices.

Steps two and three reduce to $\$3.54 \times 10^{-9}$/MWh per MMBTU saved, which is the gas supply DRIPE of \$0.49 × 10 9/MMBtu per MMBTU multiplied by the quantity of MMBtu required to produce a MWh of electricity of 7.2 MMBtu/MWh.

The cross-fuel basis DRIPE effect of reductions in retail gas use each year is:

- the quantity of retail gas saved (MMBtu), multiplied by
- the basis DRIPE (\$/MMBtu per Mcf/day saved) from Chapter 6 each year multiplied by
- the MMBtu required to produce a MWh of electricity, i.e., 7.2 MMBtu/MWh, multiplied by
- the quantity of retail electric use (MWh) subject to wholesale energy prices.

7.5.2 Fuel and Cross-Fuel DRIPE Value of Reduction in Retail Electric Use – Assumptions and Method

The gas supply DRIPE effect on energy market prices of reductions in retail electric use is:

- the reduction in electric energy (MWh), multiplied by
- $\$3.54 \times 10^{-9}$/MMBtu per MWh saved, multiplied by
- the MMBtu required to produce a MWh of electricity, 7.2 MMBtu, multiplied by
- the quantity of retail electric use (MWh) subject to wholesale energy prices.

Steps two and three reduce to $\$2.55 \times 10^{-8}$/MWh per MMBTU saved. This is \$3.54 × 10 9/MMBtu per MMBTU multiplied by the quantity of MMBtu required to produce a MWh of electricity of 7.2 MMBtu/MWh.

The basis DRIPE effect of reductions in retail electric use each year is:

- the reduction in electric energy (MWh), multiplied by.
- the basis DRIPE from Chapter 6 each year , expressed as $/TWh per quad saved, multiplied by
- the quantity of MMBtu required to produce a MWh of electricity, i.e., 7.2 MMBtu/MWh, multiplied by
- the quantity of retail electric use (MWh) subject to wholesale energy prices.

Cross-Fuel

The cross-fuel gas supply DRIPE effect of reductions in retail electric use is:

- the reduction in electric energy (MWh), multiplied by
- $2.55 × 10^{-8}/MMBtu per MWh saved, multiplied by
- the quantity of retail gas use (MMBtu) paying a price tied to the wholesale supply price.

7.6 DRIPE Effects from Gas Efficiency on Retail Customers

7.6.1 Gas Efficiency Direct DRIPE

The gas supply DRIPE for each New England state, and the total benefit for all New England gas end-use consumers, is shown in Exhibit 7-17.

Exhibit 7-17. Supply DRIPE Benefit in Annual MMBtu Load Reduction, by State

	CT	MA	ME	NH	RI	VT	New England
Annual Use in 2013 (quads)	0.1232	0.2800	0.0423	0.0243	0.0380	0.0095	0.5172
Gas efficiency supply price DRIPE effect ($ x 10^{-9}/MMBTU per MMBtu saved)	$0.060	$0.137	$0.021	$0.012	$0.019	$0.005	$0.253

The speed at which that supply DRIPE is reflected in retail rates depends upon the extent to which utilities, marketers, and self-supplying customers are hedging their purchases. Since we do not know the extent to which the gas utilities, marketers, and self-supplying customers in each state hedge their purchases, and since the specific details of those hedging arrangements are confidential, AESC 2015 assumes no hedging. Thus 100 per cent of retail gas use is assumed to benefit from gas supply price DRIPE.

AESC 2015 assumes gas supply DRIPE benefits would continue as long as the efficiency measure continues to reduce load. Gas supply DRIPE is measuring the effect of demand on the marginal cost of extraction for a finite resource.

7.6.2 Gas Efficiency Cross-Fuel DRIPE

The gas supply price DRIPE effect on annual average wholesale electric energy prices in New England due to a one MMBtu reduction in annual gas use is $3.54 × 10^{-9}/MWh per MMBtu saved, as noted above.

The basis DRIPE effect on annual average wholesale electric energy prices in New England due to a reduction in annual gas use in each state would be a function of the reduction by time period, the basis DRIPE coefficients by time period, the MMBtu required to produce a MWh of electricity (i.e., 7.2 MMBtu/MWh), and the MWh of annual electric use paying prices tied to the wholesale energy price.[198]

The basis DRIPE coefficient for the three peak winter months, December through February, from Exhibit 1-1 is presented in column a. The basis DRIPE coefficient for the remaining two months of the gas industry winter, i.e. November and March, is approximately 29 percent of the three peak month value. The resulting basis DRIPE for the five month winter is a weighted average of those two periods, as presented in Exhibit 7-18. AESC 2015 assumes that basis DRIPE will terminate after 2020. The AESC 2015 Base Case assumes that significant additional pipeline capacity will be in service by that time, which will change the New England demand / supply situation substantially relative to current market conditions. In contrast, the AESC 2015 estimate of basis DRIPE for winter months is based on current market conditions in New England. Moreover it is a high level qualitative assumption of elasticity of 1. Thus it is reasonable to assume that basis elasticity will change after 2019.

Exhibit 7-18. Basis DRIPE Coefficients by Time Period, MMBtu per Mcf/Day Saved

Year	Three peak Winter months	Two shoulder Winter months	Gas Industry Winter (Nov - March)	Summer (April - October)
	a	b = a * 29%	c = ((a* 90 days) + (b * 61 days))/ 151 days	d
2016	0.00379	0.0011	0.0024	0.0000
2017	0.00218	0.0006	0.0014	0.0000
2018	0.00095	0.0003	0.0006	0.0000
2019	0.00057	0.0002	0.0004	0.0000
2020	0.00056	0.0002	0.0004	0.0000

The DRIPE coefficients in Exhibit 7-18 are stated in terms of reductions in average daily gas load in each time period in each year. For example, a one MMBtu/day of load reduction throughout the winter is a load reduction of 90 MMBtu. Therefore the DRIPE coefficient for one MMBtu reduction in total for a

[198] Since generation everywhere in ISO-NE serves load throughout New England, the cross-price effect on electric consumers in a state is not dependent on the amount of gas burned for electric generation in that state.

given time period is much lower than the coefficient for a one MMBtu/day reduction during that same time period. Exhibit 7-19 converts the gas basis price effect per MMBtu saved per day into a gas basis price effect per quad saved in each time period.

Exhibit 7-19 Gas Basis Coefficients, $/MMBtu Reduction per Quad Saved

Year	Three peak Winter months	Two shoulder Winter months	Gas Industry Winter (Nov - March)	Baseload
Days per Period	90	61	151	Winter portion
	a = (Basis per MCF per day / # days) * 10^6	a = (Basis per MCF per day / # days) * 10^6	c = ((a* 90 days) + (b * 61 days))/ 151 days	d = c * 151 / 365
2016	$ 42.07	$ 18.12	32.4	$ 13.40
2017	$ 24.17	$ 10.41	18.6	$ 7.70
2018	$ 10.59	$ 4.56	8.2	$ 3.37
2019	$ 6.33	$ 2.73	4.9	$ 2.02
2020	$ 6.22	$ 2.68	4.8	$ 1.98

Exhibit 7-20 summarizes the gas-on-electric cross-fuel basis DRIPE coefficients, stated in dollars per TWh (million MWh) per MMBtu saved.

Exhibit 7-20. Cross-Fuel DRIPE ($/TWh per MMBtu Gas Saved)

Gas Cross DRIPE $/TWh per MMBtu saved					
		Basis		total DRIPE	
	Supply (annual)	Gas Heating (Nov to March)	Gas Baseload (annual)	Gas Heating (Nov to March)	Gas Baseload (annual)
2016	0.00354	0.23408	0.09684	0.23762	0.10038
2017	0.00354	0.13449	0.05564	0.13803	0.05918
2018	0.00354	0.05890	0.02437	0.06244	0.02791
2019	0.00354	0.03521	0.01457	0.03875	0.01811
2020	0.00354	0.03462	0.01432	0.03816	0.01786
2021	0.00354	0.00000	0.00000	0.00354	0.00354
2022	0.00354	0.00000	0.00000	0.00354	0.00354
2023	0.00354	0.00000	0.00000	0.00354	0.00354
2024	0.00354	0.00000	0.00000	0.00354	0.00354
2025	0.00354	0.00000	0.00000	0.00354	0.00354
2026	0.00354	0.00000	0.00000	0.00354	0.00354
2027	0.00354	0.00000	0.00000	0.00354	0.00354
2028	0.00354	0.00000	0.00000	0.00354	0.00354
2029	0.00354	0.00000	0.00000	0.00354	0.00354
2030	0.00354	0.00000	0.00000	0.00354	0.00354

Exhibit 7-21 summarizes the own-state and ISO-wide cross-fuel DRIPE values for gas efficiency installations based upon the coefficients in Exhibit 7-20 and that approximately 50 percent of electric energy usage occurs in the heating season.

Exhibit 7-21. Gas-to-Electric Cross-Fuel Heating DRIPE, $/MMBtu, Gas Efficiency installations

Gas Winter Heating DRIPE							
Year	CT	MA	ME	NH	RI	VT	New England
2016	$ 3.11	$ 5.79	$ 1.10	$ 1.16	$ 0.77	$ 0.57	$ 12.49
2017	$ 1.84	$ 3.36	$ 0.64	$ 0.68	$ 0.44	$ 0.33	$ 7.29
2018	$ 0.83	$ 1.51	$ 0.29	$ 0.31	$ 0.20	$ 0.15	$ 3.29
2019	$ 0.51	$ 0.94	$ 0.18	$ 0.19	$ 0.12	$ 0.09	$ 2.04
2020	$ 0.51	$ 0.92	$ 0.17	$ 0.19	$ 0.12	$ 0.09	$ 2.00
2021	$ 0.05	$ 0.09	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.19
2022	$ 0.05	$ 0.09	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18
2023	$ 0.05	$ 0.09	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18
2024	$ 0.05	$ 0.09	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18
2025	$ 0.05	$ 0.08	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18
2026	$ 0.05	$ 0.08	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18
2027	$ 0.05	$ 0.08	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18
2028	$ 0.05	$ 0.08	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18
2029	$ 0.05	$ 0.08	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18
2030	$ 0.05	$ 0.08	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.18

Gas Annual Baseload DRIPE							
Year	CT	MA	ME	NH	RI	VT	New England
2016	$ 3.28	$ 6.12	$ 1.16	$ 1.23	$ 0.81	$ 0.60	$ 13.19
2017	$ 1.97	$ 3.60	$ 0.68	$ 0.73	$ 0.48	$ 0.35	$ 7.82
2018	$ 0.93	$ 1.69	$ 0.32	$ 0.35	$ 0.22	$ 0.17	$ 3.68
2019	$ 0.60	$ 1.09	$ 0.21	$ 0.23	$ 0.14	$ 0.11	$ 2.38
2020	$ 0.59	$ 1.08	$ 0.20	$ 0.22	$ 0.14	$ 0.10	$ 2.34
2021	$ 0.12	$ 0.21	$ 0.04	$ 0.04	$ 0.03	$ 0.02	$ 0.46
2022	$ 0.12	$ 0.21	$ 0.04	$ 0.04	$ 0.03	$ 0.02	$ 0.46
2023	$ 0.12	$ 0.21	$ 0.04	$ 0.05	$ 0.03	$ 0.02	$ 0.46
2024	$ 0.12	$ 0.21	$ 0.04	$ 0.05	$ 0.03	$ 0.02	$ 0.46
2025	$ 0.12	$ 0.21	$ 0.04	$ 0.05	$ 0.03	$ 0.02	$ 0.46
2026	$ 0.12	$ 0.21	$ 0.04	$ 0.05	$ 0.03	$ 0.02	$ 0.46
2027	$ 0.12	$ 0.21	$ 0.04	$ 0.05	$ 0.03	$ 0.02	$ 0.46
2028	$ 0.12	$ 0.21	$ 0.04	$ 0.05	$ 0.03	$ 0.02	$ 0.46
2029	$ 0.12	$ 0.21	$ 0.04	$ 0.05	$ 0.03	$ 0.02	$ 0.46
2030	$ 0.12	$ 0.21	$ 0.04	$ 0.05	$ 0.03	$ 0.02	$ 0.46

Exhibit 7-22 provides a comparison of the Gas direct DRIPE and cross-fuel DRIPE 2013 for CT. AESC 2015 results are lower than AESC 2013, primarily due to the lower AESC 2015 estimate of basis DRIPE. The AESC 2015 results for other states are similarly lower than the AESC 2013 results.

Exhibit 7-22. Gas Supply DRIPE and Cross-Fuel DRIPE, AESC 2015 vs AESC 2013, CT, 2016 Installations, 15 Year Levelized (2015$/MMBtu)

CT		Gas Supply DRIPE applicable to every MMBtu Reduction	Gas to Electric DRIPE						
			RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Study	Dollars		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
		1	2	3	4	5	6	7	8	9
AESC 2013	2013$	$ 0.07	$ 0.79	$ 1.23	$ 1.37	$ 1.25	$ 0.95	$ 1.23	$ 1.11	$ 1.19
	2015$	$ 0.07	$ 0.82	$ 1.27	$ 1.42	$ 1.30	$ 0.98	$ 1.27	$ 1.15	$ 1.23
AESC 2015	2015$	$ 0.06	$ 0.64	$ 0.57	$ 0.55	$ 0.57	$ 0.61	$ 0.57	$ 0.59	$ 0.58
AESC 2015 vs AESC 2013		-14%	-22%	-55%	-61%	-56%	-38%	-55%	-49%	-53%

7.7 Fuel DRIPE Effects from Electric Gas Efficiency on Retail Customers

7.7.1 Electric Efficiency Own Fuel DRIPE Effects

The gas supply DRIPE effect of a one MWh reduction in annual electric use is $\$2.55 \times 10^{-8}$/ per MWh saved. The basis DRIPE effect of that one MWh reduction is the reduction in electric energy (MWh) multiplied by the basis DRIPE multiplied by 7.2 MMBtu/MWh. Exhibit 7-23 shows the resulting electric efficiency gas supply and basis DRIPE effects by year.

Exhibit 7-23. Annual Electric-Gas-Electric Price Benefit per MWh Saved

	Winter					
	CT	MA	ME	NH	RI	VT
2016	$22.443	$41.851	$7.912	$8.407	$5.542	$4.094
2017	$13.283	$24.268	$4.607	$4.943	$3.211	$2.391
2018	$5.999	$10.945	$2.073	$2.249	$1.443	$1.067
2019	$3.715	$6.770	$1.279	$1.402	$0.889	$0.653
2020	$3.651	$6.649	$1.254	$1.387	$0.868	$0.636
2021	$0.338	$0.616	$0.116	$0.129	$0.080	$0.058
2022	$0.338	$0.615	$0.116	$0.130	$0.080	$0.058
2023	$0.338	$0.615	$0.115	$0.130	$0.079	$0.057
2024	$0.338	$0.614	$0.115	$0.131	$0.079	$0.057
2025	$0.338	$0.613	$0.115	$0.132	$0.078	$0.056
2026	$0.337	$0.612	$0.114	$0.132	$0.077	$0.055
2027	$0.337	$0.611	$0.114	$0.133	$0.077	$0.055
2028	$0.336	$0.610	$0.113	$0.133	$0.076	$0.054
2029	$0.336	$0.609	$0.113	$0.134	$0.076	$0.054
2030	$0.336	$0.608	$0.112	$0.135	$0.075	$0.053
levelized 15	$3.97	$7.31	$1.38	$1.49	$0.96	$0.71

	Summer					
	CT	MA	ME	NH	RI	VT
2016	$14.221	$26.519	$5.013	$5.327	$3.512	$2.594
2017	$8.543	$15.607	$2.963	$3.179	$2.065	$1.538
2018	$4.022	$7.338	$1.390	$1.508	$0.968	$0.715
2019	$2.604	$4.745	$0.896	$0.983	$0.623	$0.458
2020	$2.564	$4.669	$0.880	$0.974	$0.610	$0.447
2021	$0.508	$0.924	$0.174	$0.194	$0.120	$0.088
2022	$0.507	$0.923	$0.173	$0.195	$0.119	$0.087
2023	$0.507	$0.923	$0.173	$0.196	$0.119	$0.086
2024	$0.507	$0.921	$0.172	$0.197	$0.118	$0.085
2025	$0.506	$0.920	$0.172	$0.197	$0.117	$0.084
2026	$0.506	$0.918	$0.171	$0.198	$0.116	$0.083
2027	$0.505	$0.917	$0.171	$0.199	$0.115	$0.082
2028	$0.505	$0.915	$0.170	$0.200	$0.115	$0.081
2029	$0.504	$0.914	$0.169	$0.201	$0.114	$0.080
2030	$0.504	$0.912	$0.169	$0.202	$0.113	$0.080
levelized 15	$2.76	$5.08	$0.96	$1.04	$0.67	$0.49

7.7.2 Electric Efficiency Cross-Fuel DRIPE Effect on Retail Gas Rates

Exhibit 7-24 shows the results of multiplying the estimated supply price reduction per MWh of electric efficiency by the end-use gas consumption in each state and the region to estimate the electric cross-fuel effect on retail gas prices.

Exhibit 7-24. Annual Gas Price Benefit ($ x 10-9/MMBTU per MWh Saved)

	WINTER					
Year	CT	MA	ME	NH	RI	VT
2016	$22.748	$42.547	$8.017	$8.467	$5.636	$4.118
2017	$13.589	$24.964	$4.712	$5.003	$3.306	$2.414
2018	$6.304	$11.641	$2.178	$2.310	$1.538	$1.091
2019	$4.020	$7.466	$1.384	$1.462	$0.983	$0.677
2020	$3.957	$7.345	$1.359	$1.447	$0.963	$0.659
2021	$0.644	$1.312	$0.221	$0.189	$0.174	$0.082
2022	$0.644	$1.311	$0.221	$0.190	$0.174	$0.081
2023	$0.644	$1.311	$0.220	$0.191	$0.174	$0.081
2024	$0.643	$1.310	$0.220	$0.191	$0.173	$0.080
2025	$0.643	$1.309	$0.220	$0.192	$0.172	$0.080
2026	$0.643	$1.308	$0.219	$0.192	$0.172	$0.079
2027	$0.642	$1.307	$0.219	$0.193	$0.171	$0.078
2028	$0.642	$1.306	$0.218	$0.194	$0.171	$0.078
2029	$0.641	$1.305	$0.218	$0.194	$0.170	$0.077
2030	$0.641	$1.304	$0.217	$0.195	$0.170	$0.077
levelized 15	$4.27	$8.01	$1.49	$1.55	$1.06	$0.74
	SUMMER					
	CT	MA	ME	NH	RI	VT
2016	$14.352	$26.817	$5.058	$5.353	$3.552	$2.604
2017	$8.673	$15.905	$3.008	$3.205	$2.106	$1.548
2018	$4.152	$7.636	$1.435	$1.534	$1.008	$0.725
2019	$2.735	$5.043	$0.941	$1.008	$0.663	$0.468
2020	$2.695	$4.967	$0.925	$0.999	$0.650	$0.457
2021	$0.638	$1.222	$0.219	$0.220	$0.160	$0.098
2022	$0.638	$1.221	$0.218	$0.220	$0.160	$0.097
2023	$0.638	$1.221	$0.218	$0.221	$0.159	$0.096
2024	$0.638	$1.220	$0.217	$0.222	$0.158	$0.095
2025	$0.637	$1.218	$0.217	$0.223	$0.157	$0.094
2026	$0.637	$1.217	$0.216	$0.224	$0.157	$0.093
2027	$0.636	$1.215	$0.216	$0.225	$0.156	$0.092
2028	$0.636	$1.213	$0.215	$0.226	$0.155	$0.091
2029	$0.635	$1.212	$0.214	$0.227	$0.154	$0.091
2030	$0.634	$1.210	$0.214	$0.228	$0.154	$0.090
levelized 15	$2.89	$5.38	$1.00	$1.06	$0.71	$0.50

PUC 3-28

Request:

Referencing Schedule NG-8 on Bates page 365, please explain why National Grid is not proposing to increase energy efficiency spending as an alternative to offshore wind PPAs.

Response:

At the end of the Massachusetts Section 83C evaluation process, National Grid, in consultation with the Office of Energy Resources (OER) and the Division of Public Utilities and Carriers (Division), was invited to collaborate with the Massachusetts entities who had initiated the offshore wind solicitation. The Company voluntarily selected the DWW 400 MW Facility to pursue a long-term power purchase agreement under ACES because analysis of DWW's proposal indicated that it had favorable, competitive pricing and significant net benefits for Rhode Island, including the potential to produce valuable economic benefits for the state due to its proximity to Rhode Island. This selection was intended to facilitate Governor Gina M. Raimondo's goal of increasing Rhode Island's clean energy portfolio ten-fold by 2020, through the procurement of 1,000 MW of clean energy. The Company did not approach state stakeholders to review energy alternatives that may also help meet the Governor's goal, such as energy efficiency. The Company presumes that, given the Company's approved Rhode Island energy efficiency plan, which requires the Company to implement all energy efficiency measures that are cost effective and lower cost than acquisition of additional supply, the determination by the OER and the Division to support the Company's execution of a contract with DWW was based in part on an interest in ensuring the Governor's goals were met through a diverse array of clean energy options.

PUC 3-29

Request:

Referencing Schedule NG-8 on Bates page 365, please explain why National Grid is not proposing to seek PPAs for all renewable resource types as an alternative to offshore wind PPAs.

Response:

The opportunity to procure offshore wind presented itself to Rhode Island in the form of an invitation to collaborate with Massachusetts. Massachusetts has a legislative mandate to solicit bids for offshore wind, and its first solicitation was conducted in 2017. St. 2016, c. 188, s. 12. The Revolution Wind offshore wind project and the long-term PPA offer several benefits that can only be offered by the technology and scale of such a project. The 400 MW capacity of the project brings, to name a few benefits: (1) economies of scale that achieve higher output of renewable energy at lower cost; (2) significant local economic benefits and jobs to the state and region; (3) lower energy prices for consumers; and (4) large reductions in greenhouse gas emissions. In addition, offshore wind generation technology can: (1) deliver energy close to load; (2) contribute to winter peak reliability; and (3) add diversity of supply to the state's clean energy portfolio. This package of benefits associated with offshore wind energy generation is unique within the range of renewable energy resources, which is why the Company, in consultation with the Rhode Island Office of Energy Resources and the Rhode Island Division of Public Utilities and Carriers, chose to pursue it.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

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PUC 3-31

Request:

Referencing Schedule NG-8 on Bates page 365, what time frame was used to assess the net metering levelized nominal cost?

Response:

To provide a comparison to the Revolution Wind levelized nominal cost, the Company used the most current Net Metering Bill Credit Rates. The Company's response to Data Request PUC 3-33 provides the Rate Class C-06 calculation, as of January 1, 2019.

PUC 3-32

Request:

Referencing Schedule NG-8 on Bates page 365, please explain why RE Growth 2018 Program Year and net metering have different levelized nominal costs.

Response:

To provide a comparison to the Revolution Wind levelized nominal cost, the Company provided the most recent RE Growth 2018 Program Year weighted average price and current Net Metering Bill Credit Rates. The program costs are different, as shown in the Company's response to Data Request PUC 3-33, because the RE Growth 2018 Program Year is the calculated approximate weighted average of the Performance Based Incentives from projects that were approved and awarded during the 2018 program year, while the provided Net Metering cost is the current Rate Class C-06 calculation, as of January 1, 2019.

PUC 3-33

Request:

For RE Growth 2018 Program Year and Net Metering, please provide the inputs and mathematical equations that were used to generate both tables.

Response:

REG 2018 Program Year:	Nameplate (kW)	Estimated Capacity Factor	PBI Price ($/kWh)	Estimated Annual Output (kWh)	Estimated Annual Cost ($)
	(A)	(B)	(C)	(D = A x 8760 x B)	(E = C x D)
Small--Scale Solar (Total)	6,899	0.14	$0.2855	8,461,032	$2,415,625
Medium--Scale Solar (26--250 kW DC)	240	0.14	$0.1500	294,336	$44,150
Medium--Scale Solar (26--250 kW DC)	249	0.14	$0.2275	305,374	$69,472
Medium--Scale Solar (26--250 kW DC)	249	0.14	$0.2275	305,374	$69,472
Medium--Scale Solar (26--250 kW DC)	104	0.14	$0.2300	127,546	$29,335
Medium--Scale Solar (26--250 kW DC)	248	0.14	$0.2300	304,147	$69,954
Medium--Scale Solar (26--250 kW DC)	51	0.14	$0.2445	62,546	$15,293
Medium--Scale Solar (26--250 kW DC)	66	0.14	$0.2445	80,942	$19,790
Medium--Scale Solar (26--250 kW DC)	48	0.14	$0.2445	58,867	$14,393
Medium--Scale Solar (26--250 kW DC)	250	0.14	$0.2495	306,600	$76,497
Medium--Scale Solar (26--250 kW DC)	58	0.14	$0.2495	71,131	$17,747
Medium--Scale Solar (26--250 kW DC)	250	0.14	$0.2495	306,600	$76,497
Medium--Scale Solar (26--250 kW DC)	250	0.14	$0.2495	306,600	$76,497
Medium--Scale Solar (26--250 kW DC)	250	0.14	$0.2495	306,600	$76,497
Medium--Scale Solar (26--250 kW DC)	250	0.14	$0.2495	306,600	$76,497
Commercial--Scale Solar (251-999 kW DC)	999	0.14	$0.1590	1,225,174	$194,803
Commercial--Scale Solar (251-999 kW DC)	650	0.14	$0.1695	797,160	$135,119
Commercial--Scale Solar (251-999 kW DC)	999	0.14	$0.1800	1,225,174	$220,531
Large-Scale Solar (1,000--5,000 kW DC)	5,000	0.14	$0.1110	6,132,000	$680,652
Large-Scale Solar (1,000--5,000 kW DC)	5,000	0.14	$0.1160	6,132,000	$711,312
Large-Scale Solar (1,000--5,000 kW DC)	1,549	0.14	$0.1398	1,899,694	$265,577
Wind II (3,000--5,000 kW¿ 2-turbine)	3,000	0.40	$0.1755	10,590,840	$1,858,692
Wind II (3,000--5,000 kW¿ 2-turbine)	3,000	0.40	$0.1755	10,590,840	$1,858,692
Community Remote DG Large Solar (1,000--5,000 kW DC)	1,199	0.14	$0.1850	1,470,454	$272,034
Medium--Scale Solar (26--250 kW DC)	54	0.14	$0.1975	66,226	$13,080
Medium--Scale Solar (26--250 kW DC)	123	0.14	$0.2224	150,847	$33,548
Medium--Scale Solar (26--250 kW DC)	192	0.14	$0.2275	235,469	$53,569
Medium--Scale Solar (26--250 kW DC)	42	0.14	$0.2300	51,509	$11,847
Commercial--Scale Solar (251-999 kW DC)	999	0.14	$0.1750	1,225,174	$214,405
Commercial--Scale Solar (251-999 kW DC)	964	0.14	$0.1935	1,182,250	$228,765
Community Remote DG Commercial Solar (251--999 kW DC)	997	0.14	$0.2240	1,222,721	$273,889
Community Remote DG Large Solar (1,000--5,000 kW DC)	1,800	0.14	$0.1890	2,207,520	$417,221
Medium--Scale Solar (26--250 kW DC)	78	0.14	$0.2149	95,659	$20,557
Medium--Scale Solar (26--250 kW DC)	50	0.14	$0.2200	61,320	$13,490
Commercial--Scale Solar (251-999 kW DC)	499	0.14	$0.1695	611,974	$103,730
Large-Scale Solar (1,000--5,000 kW DC)	2,930	0.14	$0.1475	3,593,352	$530,019
Small Scale Hydropower II (251 kW to 1 MW)	740	0.40	$0.2455	2,592,960	$636,572
REG 2018 Program Year (total Nameplate, approximate weighted average price):	40,326 kW			(F = sum(E)/sum(D)):	$0.18311

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

Current Net Metering Bill Credit Rates as of 1/1/2019

Rate Class C-06	($/kWh)
Standard Offer Service	$0.10990
(less Renewable Energy Standard)	($0.00004)
	$0.10986
Distribution Charge	$0.04932
Transmission Charge	$0.02728
Transition Charge	($0.00087)
Total:	$0.18559