Analysis of Benefits of Clean Electricity Imports to Massachusetts Customers

Prepared for:

Massachusetts Clean Electricity Partnership

April 25, 2016

Power Advisory LLC

John Dalton
poweradvisoryllc.com
978 369-2465

Contents

Executive Summary

Introduction

Power Advisory was engaged by the Massachusetts Clean Electricity Partnership[1] to conduct a study of the benefits of Clean Electricity Imports (CEI) to Massachusetts and New England consumers. Specifically, Power Advisory performed computer simulations of the New England wholesale electricity and natural gas markets over a 25 year period with and without the importation of a combination of Canadian hydropower and on-shore wind generation. Scenarios considered reflect the potential for legislation to be enacted in Massachusetts that would authorize electric distribution companies to contract for the delivery of 18.9 TWh per year of such power with the goal of lowering and stabilizing electricity prices and reducing greenhouse gas (GHGs) emissions.

The price of natural gas is a key driver of electricity prices in the ISO-New England market. Power Advisory simulated the interaction between New England natural gas and electricity markets with and without CEI to predict the resulting prices in these markets and the impact on GHGs in the electricity sector. The simulations produced a holistic assessment of the impact of 18.9 TWh of CEI on natural gas prices and the corresponding impact on prices and emissions in the ISO-NE electricity market.

The methodology, assumptions and results of those simulations are described in this report. The highlights of the results from those simulations, as well as the assumptions used, are described below.

<u>Highlights:</u>

The simulations reveal that importing 18.9 TWh per year of clean energy from Canada will result in substantial annual savings to Massachusetts and New England energy consumers, as well as dramatic reductions in GHG emissions. These imports will:

- Reduce wholesale electricity costs (including both energy and capacity costs) across New England by about 6% and in Massachusetts by about 8%*;*
- Reduce greenhouse gas emissions caused by electricity generation in this region by an average of 7.2 million metric tons per year;
- Reduce natural gas requirements across the region by about 10%. A substantial portion of currently proposed gas pipeline expansions were assumed to take place; and
- Result in a 5% reduction in wholesale natural gas prices that will benefit retail gas customers.

The average savings for the New England region (before the cost of these facilities are considered) would be approximately $1.072 billion each year for the 25 year study period (all dollar amounts are in constant 2020 $). The average savings (before facility costs are considered) in Massachusetts would be $603 million each year for the 25 year period.

Four different impacts from substantial imports of clean electricity create these savings: reduced natural gas prices realized by New England gas customers (Gas Consumer Savings), reduced cost of power generation caused by lower natural gas prices (Electricity Fuel Cost Savings), reduced

[1] The Massachusetts Clean Electricity Partnership includes Brookfield Renewable Energy Partners, Emera Inc., Hydro-Quebec, Nalcor Energy, New Brunswick Power, SunEdison and TDI New England.

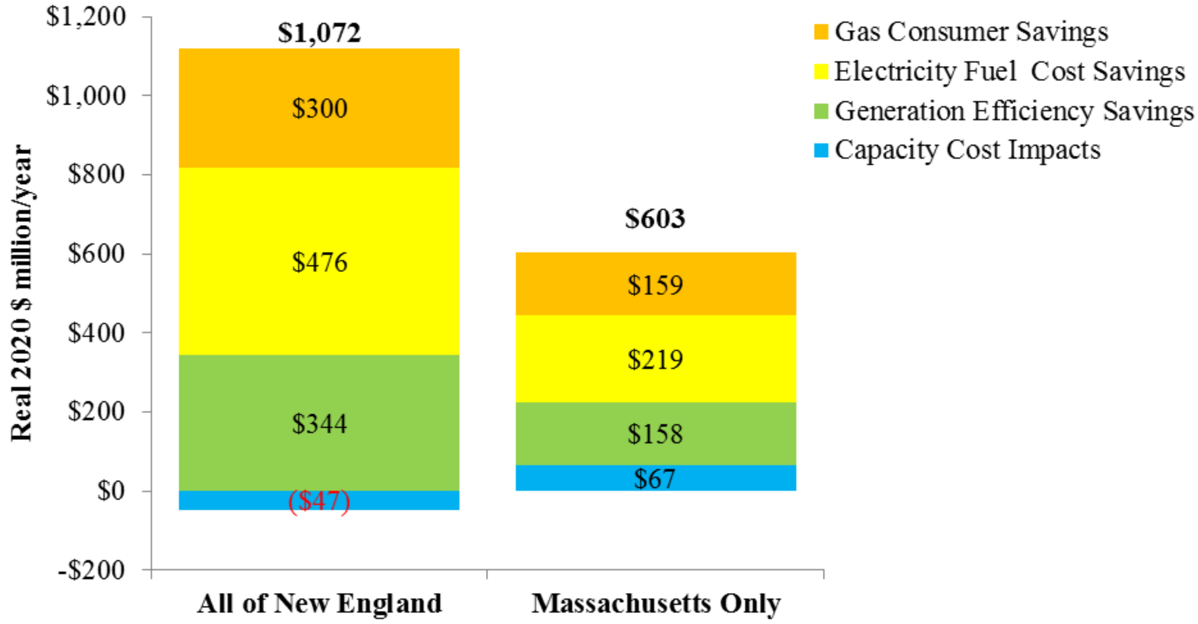
operation of the least efficient generating plants (Generation Efficiency Savings), and the capacity value of the required transmission facilities and associated long-term contracts (Capacity Cost Impacts).

1. **Gas Consumer Savings:** Consumers who use natural gas for space heating and other purposes in New England will benefit by a reduction in natural gas prices. This level of CEI is projected to result in an average savings to these customers of $300 million (2020$) per year, including $159 million per year for Massachusetts gas customers.[2]
2. **Electricity Fuel Cost Savings:** This volume of clean electricity imports will reduce the need for power to be generated by natural gas-fired power plants. As a result, regional demand for natural gas will be reduced and the price of natural gas used to produce electricity on peak demand days will be lower. This will cause a corresponding decrease in electricity prices. Therefore, this volume of clean energy imports is projected to reduce New England electricity costs by an average of $476 million per year over the study period. The portion of these savings that will be experienced by Massachusetts electricity customers is $219 million per year.
3. **Generation Efficiency Savings:** The addition of about 2,157 MW of CEI will reduce the requirements for higher cost, less efficient generating units, producing additional annual savings of $344 million in New England, including $158 million for Massachusetts customers.
4. **Capacity Cost Impacts:** Additional savings will come from the value of capacity provided by hydro power, wind power and transmission facilities combined to meet ISO-NE's Forward Capacity requirements. As a result of the capacity value of the CEI, these savings are projected to be on average $164 million per year. However, these capacity cost savings in the CEI scenario would be offset by increases in capacity prices as new entrant generators make up for revenue lost in the electricity market by seeking higher capacity prices. The simulations predict these will increase by an average of $211 million per year for all of New England, including $97 million per year for Massachusetts. (The analysis assumes that all of this capacity value can be captured by Massachusetts customers given that they are paying for the facilities and contracts that provide the capacity.) For New England as a whole, this represents an increase in costs of $47 million per year, but for Massachusetts customers it is a net savings of $67 million per year because they see only a portion of the price increase and realize all of the capacity value.

The average annual savings of these four categories of savings is shown in Figure ES-1 for both the entire New England region and the portion of those savings that will be experienced by Massachusetts customers. As mentioned earlier, the average annual savings for the region would be approximately $1.072 billion and the average savings in Massachusetts would be $603 million each year.

[2] All $ values presented are 2020$.

Figure ES-1: Average Annual Savings from Clean Electricity Imports (Millions of 2020$ per year)



Source: Power Advisory

Greenhouse Gas Reductions

In addition to energy cost savings, this volume of CEI would also produce dramatic reductions in GHGs compared to scenarios where the region does not increase the use of clean energy beyond that called for by existing state Renewable Portfolio Standards. The simulations show that this volume of CEI would reduce greenhouse gas emissions by about 7.2 million metric tons per year. This reduction is equal to about 10% of the 2050 GHG reduction required by the *Massachusetts Global Warming Solutions Act (GWSA)* and would represent about 20% of the interim 2030 target that has been adopted by the New England Governor's Conference and Eastern Canadian Premiers. The *GWSA* requires an 80% reduction in GHG emissions relative to 1990 levels by 2050 and there is no doubt the electricity sector will be relied upon to provide a substantial share of these emission reductions.

Projected Net Benefits of CEI

The costs and benefits of the CEI scenario were compared to a "Business as Usual" (BAU) scenario (that complies with the requirements of the various state Renewable Portfolios Standards but does not make a meaningful contribution to achieving the GHG reductions required by the *GWSA).*[3]

To compare these two scenarios, Power Advisory developed estimates of the range of delivered costs of the CEI to Massachusetts load centers. Low, base and high delivered cost estimates were

[3] By offering 18.9 TWh of clean energy in 2020, the CEI case front loads its GHG emission reductions, a benefit that hasn't been quantified, but is significant given that GHG emissions impacts are cumulative.

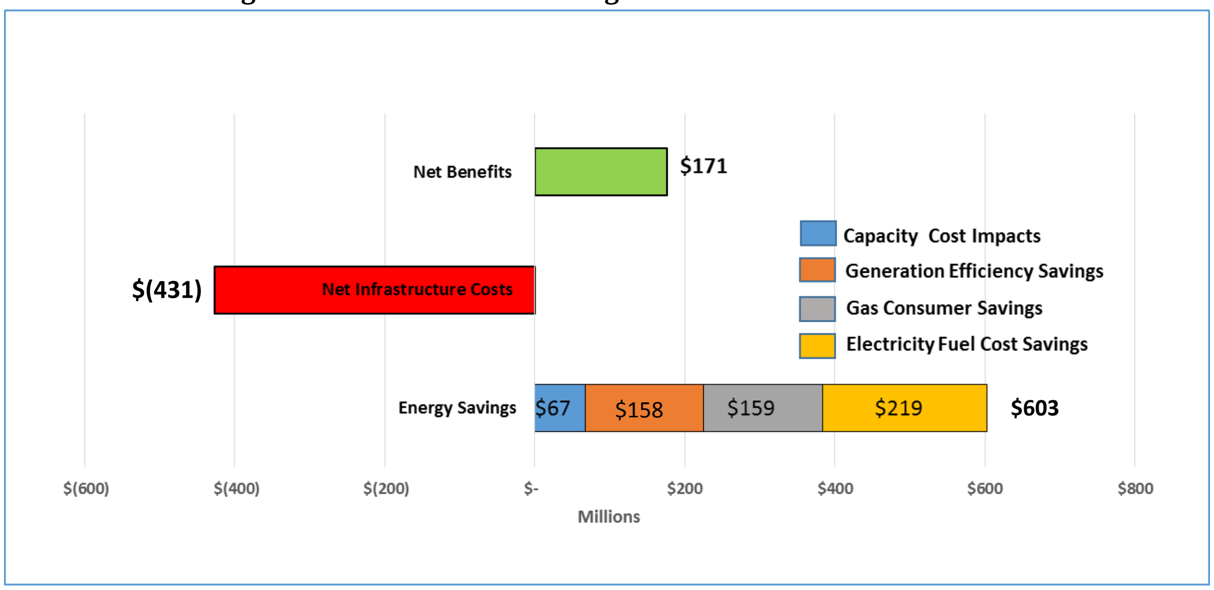
developed, but only the results of the base case are reported here.[4] Three major cost components were included to arrive at the cost estimates for clean electricity imports:

- costs of power generation;
- costs of transmission incurred in Canada to deliver the power to the New England border; and
- costs of transmission to deliver the power from the Canadian border to New England load centers.

The delivered cost for the CEI scenario reflects the capital and fixed operating and maintenance costs for hydroelectric generation found in the *Capital Cost Review of Power Generation Technologies*, increased by the cost of Canadian transmission. The CEI scenario assumes that 100% of the energy is provided by hydroelectric generation, but ultimately would likely include some wind generation.

Figure ES-2 shows the annual net savings to Massachusetts Consumers from the CEI scenario. The Net Infrastructure Costs are the combined costs of: (1) the required generation resources; (2) transmission in Canada; and (3) transmission facilities in New England to deliver the CEI from the border with Canada to Massachusetts load centers, after the value of the energy deliveries (18.9 TWh per year) are considered. These Net Infrastructure Costs are then compared to the four benefits discussed above: (1) Capacity Cost Impacts; (2) Generation Efficiency Savings; (3) Gas Consumer Savings; and (4) Electricity Fuel Cost Savings. After these benefits are considered and the Net Infrastructure Costs subtracted from them, Massachusetts Consumers would realize a Net Benefit of $171 million per year.

Figure ES-2: Annual Net Savings to Massachusetts Consumers



Source: Power Advisory

[4] The results of the low and high case are reviewed in the body of the report.

The comparison reveals that the CEI scenario offers savings of $171 million per year[5] in wholesale electricity and natural gas costs relative to Business as Usual. As noted above, the CEI scenario provides a reduction of 7.2 million tons in GHG emissions each year compared to no incremental GHG emission reductions beyond those achieved by meeting Renewable Portfolio Standards.

Methodology

Given the amount of new clean energy generation that has been proposed in several bills now before the Massachusetts legislature, the study modeled the impacts that 18.9 TWh per year of around-the-clock CEI would have on Massachusetts and New England electricity customers. This scenario was compared to a Business As Usual (BAU) scenario where no additional action is taken to achieve the *GWSA* mandates. A 25-year study period (2020-2044) was considered.

Recognizing the critical role that natural gas prices play in setting energy prices in the ISO-New England market, the interrelationship between New England natural gas and electricity markets and prices in these markets was modeled. This is a major refinement in the electricity market modeling which has not been reflected in other studies that have evaluated the benefits of such imports.

The analysis also separately modeled the capacity revenues that new natural gas plants (either combustion turbine or combined cycle) would need to earn to commit to build new capacity under ISO-NE's Forward Capacity Auction. Capacity prices are generally set by the residual revenue requirements of new natural gas plants, which are their capital and fixed operating costs minus what they expect to earn in the wholesale energy market. Therefore, if electricity market prices fall, new plants will require higher capacity prices to meet their total revenue requirements.

Capital costs for hydroelectric resources were based on the recommended values presented in the *Capital Cost Review of Power Generation Technologies.*[6] While Canadian transmission costs would be project- and location-specific, the basis for the Canadian transmission cost estimate is the Hydro-Quebec TransEnergie transmission tariff. The costs of transmission facilities to deliver the electricity from the Canadian border to Massachusetts load centers, are derived from project cost estimates for major transmission projects that have been proposed to deliver energy from the New England border to Southern New England load centers.[7] For the purposes of the cost comparisons, the report assumes that the cost of these New England transmission facilities would be paid by Massachusetts customers.

[5] Differences between BAU and CEI total costs shown in Figure 2 are $176 million and reflect rounding.
[6] Energy and Environmental Economics, Inc., March 2014.
[7] TDI's New England Clean Power Link has a cost of $1.2 billion and delivery capability of 1,000 MW and Northern Pass has a cost $1.6 billion and a delivery capability of 1,090 MW. A capital cost of $2.8 billion was used to deliver CEI to Massachusetts load centers.

1 Introduction

1.1 Background

The Massachusetts Legislature is considering several legislative proposals that would encourage electric distribution companies to contract for the delivery of 18.9 TWh per year of clean electricity imports from Canada.[8] The Massachusetts Clean Electricity Partnership (Partnership) engaged Power Advisory to conduct a study on the impacts of importing Canadian hydroelectric energy and wind power on electricity prices and greenhouse gas emissions in Massachusetts and the broader ISO-New England (ISO-NE) electricity market, which establishes the wholesale electricity prices that Massachusetts customer typically pay.[9] This report presents the results of this study.

1.2 Relevant Experience of Power Advisory

Power Advisory is an electricity sector focused management consulting firm. We specialize in electricity market analysis and strategy, power procurement, policy development, regulatory and litigation support, market design, and project development and feasibility assessment, focusing on North American electricity markets.

Power Advisory has extensive experience performing evaluations of major generation and transmission investments including a market study and testimony before the Nova Scotia Utility and Review Board on the $1.6 billion high voltage Direct Current (HVDC) undersea transmission link between Newfoundland and Nova Scotia and a market study on the $1.3 billion Western Grid, a proposed HVDC transmission between Manitoba, Saskatchewan, and Alberta. We offer a strong understanding of New England energy policy issues and its electricity sector. We have provided energy and capacity price forecasts for generation developers and asset owners and various governments and defended these forecasts before investors, lenders and regulators.

1.3 Report Outline

The first Chapter is this introduction. Chapter 2 reviews our modeling approach and assumptions. Chapter 3 reviews the results of our analysis focussing on benefits. Chapter 4 compares these benefits with the costs of necessary infrastructure and energy to be procured under long-term contract and assesses the net benefits of the CEI under different cost scenarios.

[8] A TWh represents a million MWh. New England’s forecast electricity demand for 2020 is about 150 TWh, such that this volume of energy would represent about 13% of forecast New England energy consumption.
[9] The Massachusetts Clean Electricity Partnership includes Brookfield Renewable Energy Partners, Emera Inc., Hydro-Quebec, Nalcor Energy, New Brunswick Power, SunEdison and TDI New England.

2 Assumptions and Modeling Approach

2.1 Study Methodology

Given the amount of new clean energy generation that has been proposed in several bills now before the Massachusetts legislature, the study modeled the impacts that 18.9 TWh per year of around-the-clock CEI would have on Massachusetts and New England electricity customers. This scenario was compared to a Business As Usual (BAU) scenario where no additional action is taken to achieve the *GWSA* mandates. A 25-year study period (2020-2044) was considered.

The BAU scenario incorporates current Renewable Portfolio Standard policies in New England and the development of renewable energy to satisfy these policies. The supply mix has not been adjusted further to meet New England's emissions cap under Regional Greenhouse Gas Initiative (RGGI) or the potential need for additional greenhouse gas (GHG) emission reductions under the 2020 interim targets in the *Global Warming Solutions Act* or The Conference of New England Governors and Eastern Canadian Premiers agreement to cut GHG emissions as much as 45% below 1990 levels by 2030. The CEI scenario assumes the same amount of renewable generation not including the CEI.

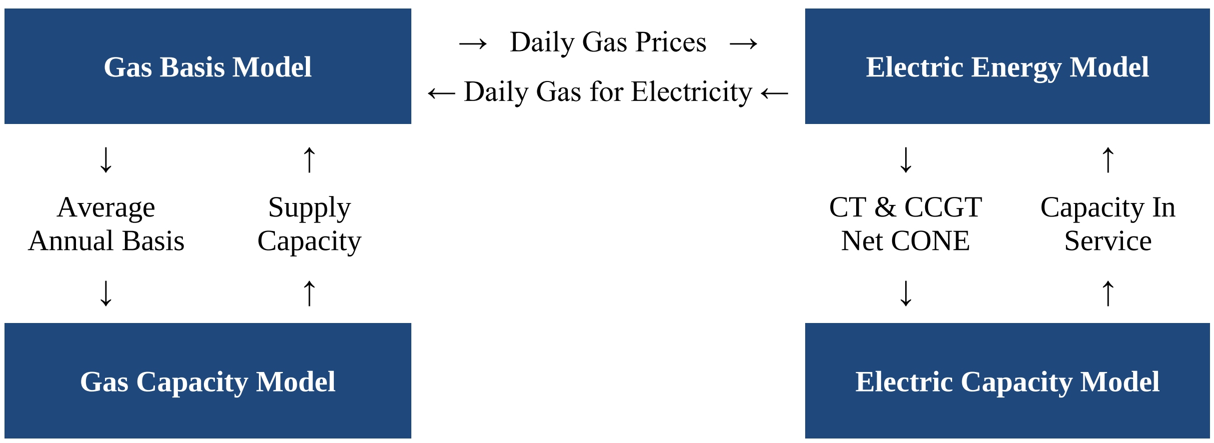
Recognizing the critical role that natural gas prices play in setting energy prices in ISO-NE and the impact on natural gas prices of competition between natural gas-fired generators and local gas distribution companies for natural gas supplies during peak natural gas demand periods, Power Advisory modeled the interrelationship between New England natural gas and electricity markets and prices in these markets. This allowed us to assess the impact of this volume of CEI on natural gas prices and the corresponding impact on prices in the ISO-NE energy market.

Specifically, Power Advisory linked a natural gas model that projected basis differentials based on pipeline utilization rates with our New England electricity market model. The natural gas model forecasts the daily New England basis differential (Algonquin Citygate versus Henry Hub) based on delivery capability (including LNG) and projected natural gas consumption for both electricity generation and for heating and industrial uses for that day. Gas delivery capability is added as needed to keep the basis within reasonable levels, as a consistently high average basis will incent local gas distribution companies to contract for additional pipeline capacity.

Total electricity capacity additions are driven by demand growth and retirements, and are the same in both scenarios. The incremental capacity requirements are assumed to be met by either simple cycle combustion turbines (SCCTs) or combined cycle combustion turbines (CCGTs), with the mix varying in the two scenarios based on which has the lowest Net Cost of New Entry (Net CONE). This is a function of the net margins that each earns in the energy market and their respective revenue requirements.

Our dispatch and market analysis model reflects anticipated changes in generation resources over time as well as changes in fuel costs and carbon allowance prices under RGGI. The model also calculates net energy market revenues for SCCTs and CCGTs, which are then fed into the capacity model to calculate Net CONEs, which determines the form of capacity additions (SCCTs or CCGTs). Hourly gas-fired generation levels are used to calculate daily gas consumption for electricity generation, which is fed into the gas price model and drives that daily gas price basis differentials, as discussed above. The gas capacity and energy models and the electricity capacity and energy models are iterated until the gas and electricity capacity additions are consistent with gas and electricity energy market prices.

Figure 1: Information Flows Between Model Components



2.2 Key Assumptions

This section reviews the key assumptions including electricity load growth, natural gas prices, electricity capacity requirements, and GHG emissions and allowance prices.

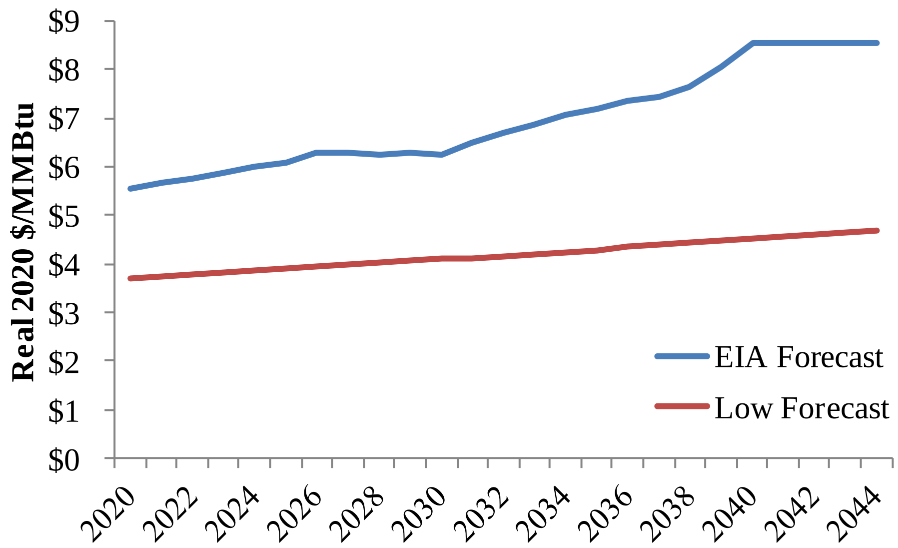
2.2.1 Load Growth

Annual electric energy demand growth is based on the net load growth forecast presented in the 2015 ISO-NE Capacity, Energy, Load and Transmission (CELT) Report after deducting Behind-the-Meter PV and Passive Demand Resources.   The load growth forecast in the CELT Report is held constant throughout the end of the forecast horizon. The peak demand growth is also from the 2015 CELT Report and also takes Behind-the-Meter PV and Passive Demand Resources into account. This results in a peak demand growth rate of about 0.6% per year throughout the analysis period. This peak demand growth doesn't account for the potential for increased electrification of the transportation sector and heating end-uses (e.g., increased penetration of mini-split heat pumps).

2.2.2 Natural Gas Prices

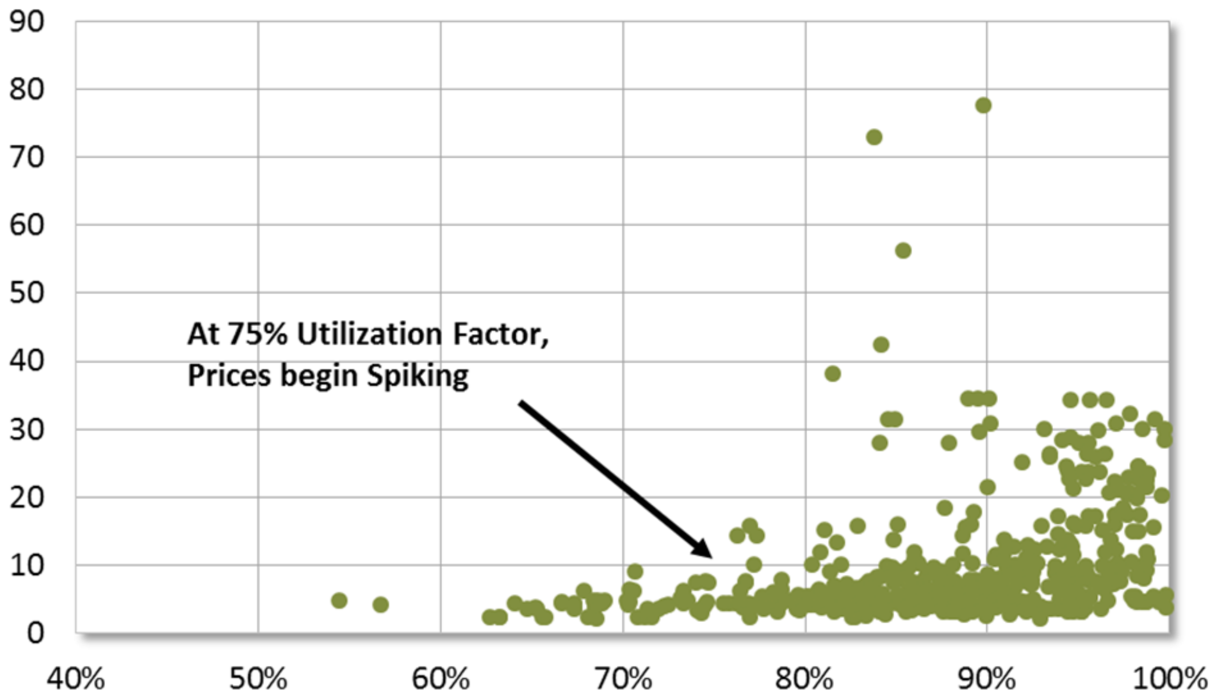
We evaluated two separate Henry Hub natural gas price forecasts to assess the impact of the considerable uncertainty associated with natural gas prices. We used the US Department of Energy Energy Information Administration's Henry Hub natural gas price forecast presented in its *Assumptions to the Annual Energy Outlook 2015*. This is the Base Case given that it is from an independent, widely-relied-upon source. We also reran the models using a lower natural gas price outlook to test the robustness of results.   These two Henry Hub natural gas forecasts are presented in Figure 2.

Figure 2: Henry Hub Natural Gas Price Forecasts



As discussed above, we have forecast the Henry Hub - Algonquin Citygate basis differential based on the historical relationship between this basis differential and natural gas pipeline capacity, and gas demand. This relationship is shown in Figure 3. Experience indicates that as this basis differential increases, New England customers, primarily New England gas distribution companies who have responsibility for serving natural gas customers, contract for additional pipeline capacity. However, it appears that building additional pipeline capacity and securing the necessary regulatory approvals to do so is increasingly difficult. To reflect this market response, we assumed that additional delivery capability will be added when the annual average basis differential is above $2.50/MMBtu (2015$), which is marginally higher than the estimated cost of new pipeline capacity that is being proposed to serve New England. Assuming that this pipeline capacity can be built without significant delays or incremental costs in the BAU scenario is another conservative assumption since delays or the inability to develop this capacity would result in higher natural gas costs than we have projected and greater benefits attributable to the CEI. Over time natural gas prices in the BAU and CEI scenarios converge and the gas price reduction benefits offered by the CEI are forecast to disappear. Ultimately, less incremental gas pipeline capacity is needed in the CEI scenario than in the BAU scenario. This is considered a production cost savings.

Figure 3: Algonquin Citygate Basis to Henry Hub ($/MMBtu) versus Pipeline Utilization Rates



Source: ICF

In both the BAU and CEI scenarios, New England's gas supply capacity is assumed to increase by 0.342 Bcf/day in 2017 due to the Algonquin AIM project, 0.072 Bcf/day in 2018 due to the Tennessee Connecticut Expansion project, and 0.55 Bcf/day in 2019.[10]

2.2.3 Electricity Capacity Requirements

The transmission facilities built to deliver the 18.9 TWh per year of energy to New England load centers and the long-term energy supply contracts that underpin these facilities are assumed to have a capacity value of about 2,100 MW.[11] We assume that this capacity value is realized over a three-year period, not in one year – i.e., that the approximately 700 MW of additional capacity value in each of these three years is used to avoid the need for new capacity that would otherwise be required to address load growth and retirements. Given forecasted retirements and load growth, such a phase-in schedule would limit the impacts on prices in the FCA. This is another conservative assumption.

[10] On April 20, 2016, Kinder Morgan Inc. indicated that it hadn't received sufficient contractual commitments from electric customers to make its Northeast Energy Direct project viable. Spectra Energy Corporation continues to pursue the development of its Access Northeast project, which would serve customers in New England. If this project were not go forward our analysis may significantly understate the benefits of this CEI.

[11] Ultimately, what suppliers offer will be determined by the form of competitive solicitation. However, based on the Clean Energy RFP and past Class I Renewable Energy RFPs, we expect that the evaluation framework will be focused on comparing costs with the power supply benefits. Therefore, providing firm energy which has a capacity value will enhance the value of a supplier's offer. Alternatively, some suppliers might elect offer a non-firm product, but at a price that they view as more competitive than firm power offerings.

2.2.4 Electricity Capacity Prices

As discussed above, capacity prices are projected based on our estimate of the form of natural gas-fired generating capacity that offers the lowest overall capacity cost and as such would be selected in the Forward Capacity Auction. We first estimate the annual fixed capital and operating and maintenance costs for these units, recognizing the difference between different technologies (e.g., SCGTs vs. CCGTs) and then subtract from these annual fixed costs the net energy margins that these units are projected to earn in the capacity market. The cost of new entry for CCGTs estimated by ISO-NE for FCA #10 as part of the Minimum Offer Price Rule was $12.64/kW-month. ISO-NE projects a higher CONE for SCGTs than for CCGTs, which we find counter intuitive, particularly given that two of the successful natural gas-fired bidders in the last two Forward Capacity Auctions (FCAs) were SCGTs. We estimate a CONE for SCGTs of $9.48/kW-year for FCA #10 (2019-2020). CONEs for future auctions are assumed to increase at the rate of inflation.

An important refinement to the market modeling and these savings estimates is to recognize that the reductions in energy market prices are likely to affect capacity prices. In the FCA administered by ISO-NE, prices are set by new entrants. Given the structure of the FCA, generation developers typically estimate the net margins that they will be able to earn based on the participation in the energy and ancillary services market and subtract these net energy margins from their estimated annual revenue requirements to determine the incremental annual revenues that they will require from the FCA. Therefore, reductions in net energy margins earned by such generating units are likely to result in an increase in FCA prices.

Setting capacity prices is therefore an iterative process. The energy model produces forecasts of hourly energy market prices. Based on these, and forecasts of daily gas prices, the capacity model estimates the expected net market revenue of both SCGTs and CCGTs. This is used to calculate Net CONE for each (CONE minus net market revenue). The model fills capacity needs (growth in capacity requirements plus retirements minus increased capacity from renewables) with either SCGTs or CCGTs, whichever has the lowest Net CONE. This changes the supply mix, which changes the energy price forecasts, which requires further changes in the supply mix.

2.2.5 GHG Emissions and Allowance Prices

The BAU scenario is not optimized to ensure that RGGI targets are satisfied. The supply mix in the BAU scenario assumes a continuation of existing policies, such as the current Renewable Portfolio Standards, rather than assuming additional efforts to meet a specific goal. The CEI scenario makes the same assumptions, except with CEI reducing the need for domestic generation and associated carbon emissions. GHG emissions are therefore significantly lower in the CEI scenario than in the BAU scenario.

Carbon allowance are projected to reach $43/ton (in nominal dollars) by 2044. This assumes a continuation of RGGI with moderate annual increases rather than a higher regional or nation-wide price. Conservatively, we have assumed that GHG allowance prices are the same in both scenarios. A case could be made that by reducing requirements for GHG allowances, the CEI scenario would result in lower GHG allowance prices, which would further reduce consumer energy costs. This would represent an incremental benefit of the CEI scenario, but one that we haven’t attempted to quantify. In effect, we are assuming that the emission reductions due to CEI are used to decrease the RGGI cap and provide a net reduction in GHG emissions relative to the cap or alternatively are banked and used for compliance with future year GHG emission reduction obligations. (If the cap was unchanged, then the emission reductions would mean a lower RGGI price, with higher emissions elsewhere in the RGGI area – i.e., the decrease in New England's emission would be offset by an increase in emissions elsewhere and no net emissions reduction.)

It is possible that GHG allowance prices could be significantly higher than what we have assumed. Allowance prices are likely to be an important component of policies to achieve state, regional and national emission reduction targets, and the allowance price levels required to incent the required level of emission reductions may be considerably higher than the moderate annual increases used in our model. High allowance prices would increase the benefits of CEI.

2.3 Cost Analysis

To estimate the net benefits provided by these CEI, estimates of the delivered cost of these imports to Massachusetts load centers were developed. Given the uncertainty regarding these delivered CEI costs low, base and high delivered cost estimates were developed. There are three major cost components for these imports: (1) the costs of generation; (2) transmission costs incurred in Canada; and (3) the cost of transmission to deliver the energy and capacity from the Canadian border to Massachusetts load centers. The basis for estimating each of these costs components are reviewed below.

2.3.1 Generation Costs

Generation costs were estimated for hydroelectric and wind resources. The capital costs and fixed operating and maintenance costs for the hydroelectric resources were based on the recommended values presented in the *Capital Cost Review of Power Generation Technologies*, which reviewed a range of hydroelectric generation capital and fixed operating and maintenance costs. This source was used because it was recently published and considered a range of cost estimates for hydroelectric projects.

Given their long useful life (upwards of 100 years with appropriate capital replacement), a forty-year cost recovery period was assumed for a hydroelectric plant. A sixty percent capacity factor was assumed and 8% losses for energy deliveries to Southern New England.[12][13] The wind project capital and fixed operating and maintenance costs were based on estimates presented in the U.S. Energy Information Administration's *Assumptions to the Annual Energy Outlook 2015*. A 40% capacity factor was used for wind generation given the attractive wind regimes in Atlantic Canada and Quebec and the increased application of larger rotor diameters, which offer increased yields.

[12] We would expect that suppliers with large portfolios would supplement this energy with existing supply or other clean energy resources.
[13] This 8% losses is appropriate given the assumed reliance on HVDC transmission facilities, which reduce losses relative to AC transmission facilities.

2.3.2 Transmission Costs

The Canadian transmission costs clearly would be project and location specific. With Québec a possible source for such imports, the starting point for our Canadian transmission cost estimate was the Hydro-Québec TransÉnergie transmission tariff. In the high delivered cost scenario, we assumed a doubling of this transmission tariff. Given the relatively high cost of the TransÉnergie tariff, the transmission costs in the high delivered cost scenario can be viewed as not inconsistent with transmission costs in other jurisdictions with lower transmission tariffs for facilities where there's an additional capital contribution required to reinforce the transmission network or connect to the network.

Finally, for the costs of transmission facilities to deliver the electricity from the Canadian border to Massachusetts load centers we relied on project cost estimates for other major import projects (i.e., Northern Pass ($1.6 billion) and the New England Clean Power Link ($1.2 billion)). Our US transmission facilities cost estimate of $2.8 billion recognized that two such HVDC facilities would likely be required to deliver 18.9 TWh per year of energy.

While this volume of imports would produce significant production cost savings and as a result the New England transmission facilities could qualify as Market Efficiency Transmission Upgrades under the ISO-NE transmission tariff, we did not assume that the cost of these facilities would be rolled into the ISO-NE transmission tariff such that their costs would be shared by all New England customers. This can be viewed as another conservative assumption given that other New England states are contemplating purchases of such clean energy as indicated by the recent Clean Energy RFP issued jointly by Massachusetts, Connecticut, and Rhode Island.

3 Study Results

This chapter summarizes the results of the analysis.

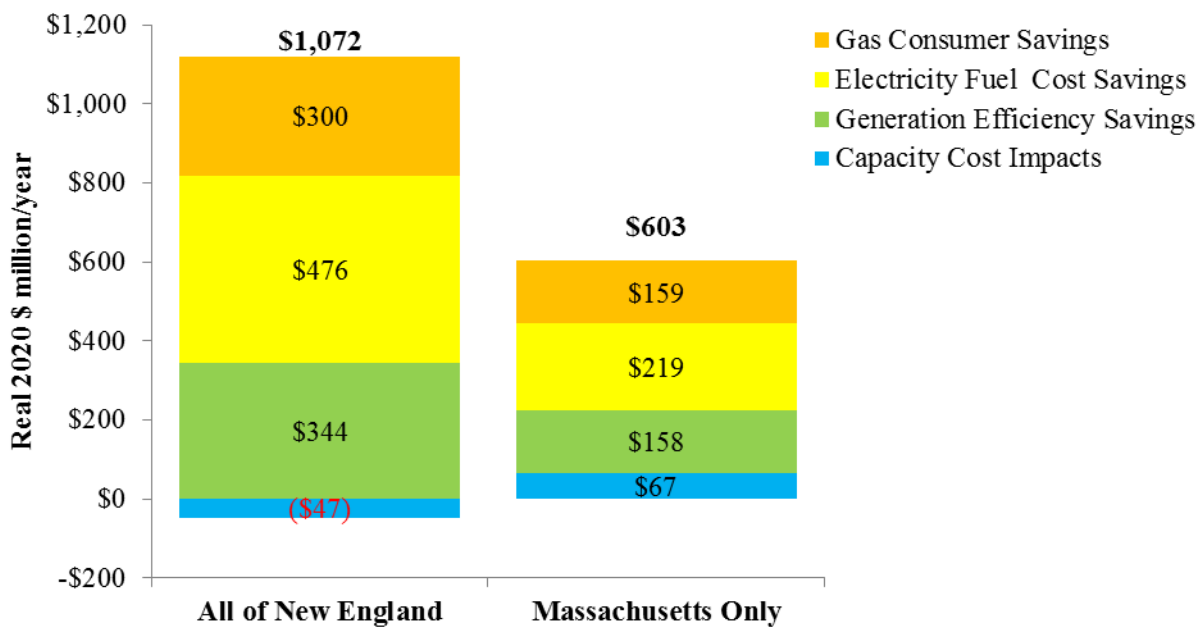
Importing 18.9 TWh per year of CEI produces four different types of impacts which generate the savings realized by customers: reduced natural gas prices realized by all New England gas customers (Gas Consumer Savings), reduced cost of power generation caused by lower natural gas prices (Electricity Fuel Cost Savings), reduced operation of the least efficient generating plants (Generation Efficiency Savings), and the capacity value of the required transmission facilities and associated long-term contracts (Capacity Cost Impacts). Each of these impacts is summarized below for the base case natural gas outlook and then discussed in greater detail in a subsequent section of this chapter.[14]

1. **Gas Consumer Savings:** Consumers who use natural gas for space heating and other purposes in New England will also benefit by a reduction in natural gas prices. This level of CEI is projected to result in an average savings to these customers of $300 million (2020$) per year, including $159 million per year for Massachusetts gas customers.[15]
2. **Electricity Fuel Cost Savings:** This volume of clean electricity imports will reduce the need for power to be generated by natural gas-fired power plants. As a result, regional demand for natural gas will be reduced and the price of natural gas used to produce electricity on peak demand days will be lower. This will cause a corresponding decrease in electricity prices. Therefore, this volume of clean energy imports is projected to reduce New England electricity prices by an average of $476 million per year over the study period. The portion of these savings that will be experienced by Massachusetts electricity customers is $219 million per year.
3. **Generation Efficiency Savings:** The addition of about 2,157 MW of CEI will reduce the requirements for higher cost, less efficient generating units, producing additional annual savings of $344 million in New England, including $158 million for Massachusetts customers.
4. **Capacity Cost Impacts:** Additional savings will come from the value of capacity provided by that hydro power, wind power and transmission facilities combined to meet ISO-NE's Forward Capacity requirements. As a result of the capacity value of the CEI, these savings are projected to be on average $164 million per year. However, these capacity cost savings in the CEI scenario would be offset by increases in capacity prices as new entrant generators make up for revenue lost in the electricity market by seeking higher capacity prices. The simulations predict these will increase by an average of $211 million per year for all of New England, including $97 million per year for Massachusetts. (The analysis assumes that all of this capacity value can be captured by Massachusetts customers given that they are paying for the facilities and contracts that provide the capacity.) For New England as a whole, this represents an increase in costs of $47 million per year, but for Massachusetts customers it is a net savings of $67 million per year because they see only a portion of the price increase and realize all of the capacity value.

[14] The results of the low natural gas price case are presented in Appendix A.
[15] All $ values presented are 2020$.

The average annual savings of these four categories of savings is shown in Figure 4 for both the entire New England region and the portion of those savings that will be experienced by Massachusetts customers. As mentioned earlier, the average annual savings for the region would be approximately $1.072 billion and the average savings in Massachusetts would be $603 million each year.

Figure 4: Average Annual Savings from Clean Electricity Imports (Millions of 2020$ per year)



3.1 Projected Natural Gas Cost Savings

As discussed in the previous chapter, the impacts of the 18.9 TWh per year of clean energy imports were derived by comparing the results of the BAU case to the base CEI case over the 25-year study period from 2020 to 2044. This volume of imports will have a substantial impact on New England's gas market; the delivery of 2,157 MW per hour around the clock is projected to reduce natural gas consumption by about 0.3 Bcf/day on average over the analysis period. Given the significant pressure on New England's natural gas supply infrastructure, particularly on very cold days when natural gas demand is highest, this reduction in demand is forecast to result in a 5% reduction in natural gas prices in the CEI scenario.

However, with increasing natural gas demand, New England will require additional gas supply capacity. In the BAU case, new natural gas pipeline capacity is projected to be needed around 2031, but in the CEI case this is delayed until approximately 2041. The CEI case is projected to reduce the cumulative need for delivery capability by 0.5 Bcf/day.[16] The model assumes that enough gas infrastructure is added to keep the gas price basis at a reasonable level (the same in both scenarios), so the difference in gas prices between the two scenarios narrows starting in 2031, and disappears by 2041.

Lower gas prices translate into a direct benefit to New England residential, commercial and industrial natural gas consumers. With natural gas costs largely a pass through for electricity generators, gas generators don't benefit to the same degree as electricity customers.[17] Savings to electricity generators are not included in our estimates of total consumer savings in order to avoid double-counting. New England consumers save an average of $300 million per year (2020$) over the entire study period (2020-2044).[18] Massachusetts gas customers realize savings of $158 million per year over the study period.

3.2 Electricity Fuel Cost Savings

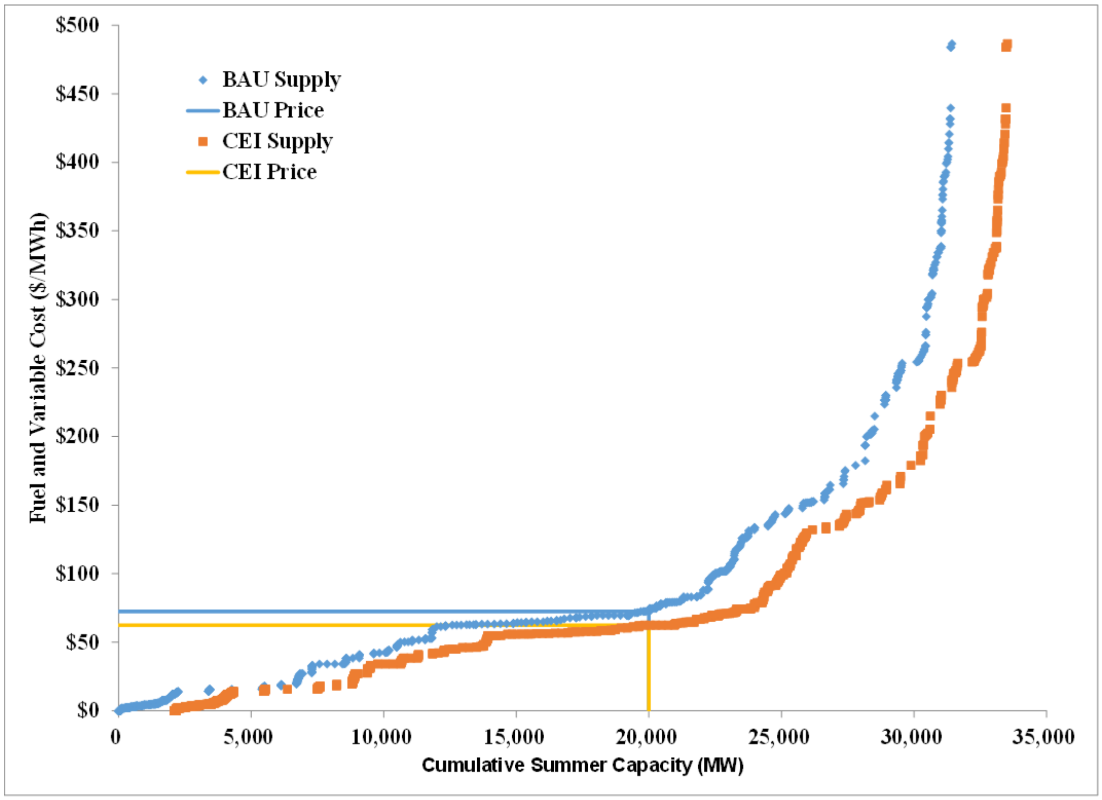
Given that natural gas is the predominant fuel for electricity generation in New England, the reduction in regional natural gas supply costs identified above also results in a significant reduction in fuel costs for electricity generators and this translates into reduced electricity prices for customers. New England customers are projected to realize average savings of $476 million per year and Massachusetts customers savings of $219 million per year.

3.3 Generation Efficiency Savings

Adding about 2,157 MW of CEI to the ISO-NE supply mix will displace less efficient higher cost generating units and produce meaningful savings for customers. In essence this volume of CEI shifts the supply curve to the right and by so doing reduces electricity prices. This is shown in Figure 5.

[16] The difference between delivery capability and impact on natural gas demand reflects the fact that delivery facilities operate below their capability during shoulder periods.
[17] Lower gas prices result in some margin compression for more efficient natural gas-fired generators.
[18] All $ values presented are in 2020$ unless otherwise noted.

Figure 5: ISO-NE Electricity Supply Curve With and Without 2,157 MW of CEI

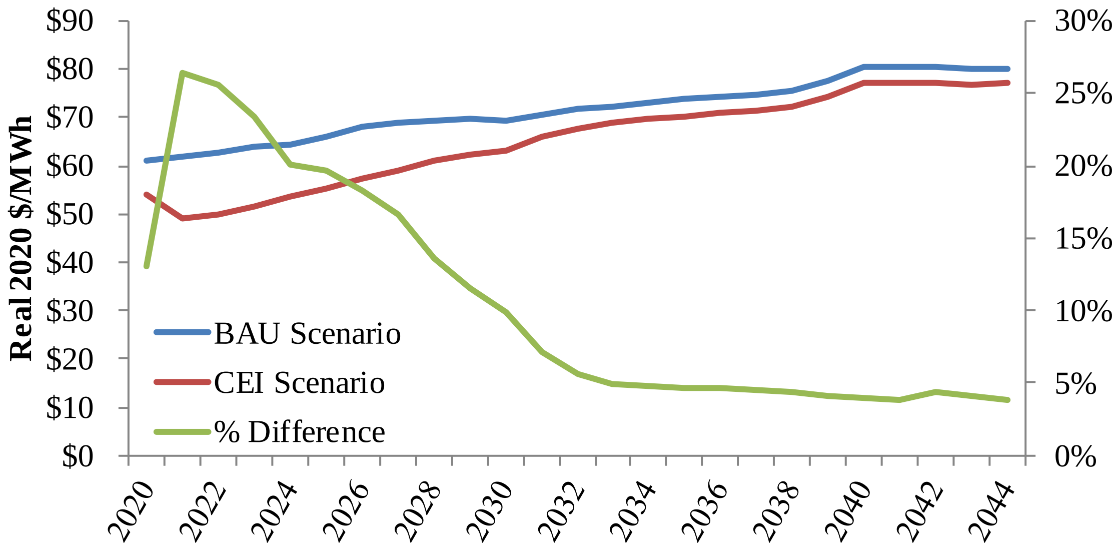


Source: SNL

Adding 2,157 MW of CEI would produce annual average savings of $344 million for all of New England and $158 million for Massachusetts customers.

Figure 6 shows the combined impact on electricity fuel cost savings and generation efficiency savings on wholesale electricity prices.

Figure 6: New England Wholesale Electricity Price Forecasts



Source: Power Advisory

3.4 Capacity Impacts

Massachusetts customers will realize additional savings from the capacity value of the proposed transmission facilities and the volumes of energy flowing over these facilities under the long-term contracts that ensure the delivery of the CEI. We assumed that the transmission facilities and energy deliveries supported by these contracts would have a capacity value of almost 2,100 MW. The assumptions for CONE and estimating capacity prices were reviewed in the previous chapter.

We estimated the anticipated increase in capacity prices by projecting the change in net margins earned by SCGTs and CCGTs. The energy cost savings that we projected for the CEI scenario are anticipated to result in an increase in capacity prices over the analysis period of about $211 million per year.

Not surprisingly, these forecasted increases in capacity prices reduced the anticipated number of generator retirements. The generating units that are at greatest risk of retirement generally operate relatively few hours and are heavily reliant on capacity revenues. Therefore, a forecast increase in capacity revenues is likely to reduce the level of such retirements.[19]

Taking into account both decreases in net market revenue and increases in capacity prices, overall margins for baseload generators are projected to decline. Given their importance in generating non-carbon emitting electricity, the reduction in gross margins earned by nuclear units are particularly

[19] ISO-NE recently introduced the Pay for Performance Program, which will penalize generating units that are not available during periods when additional capacity is required. This is expected to increase the level of retirements of such generating units given that the Pay for Performance Program will potentially reduce these generator's capacity revenues and increase their operating risks. This is an impact of the Pay for Performance Program not of increased levels of clean energy imports.

important. These are forecast to decline by 7% for nuclear units over the study period. The decrease in nuclear revenues is not expected to be substantial enough to induce retirements. Given their higher variable operating costs, the gross margins for coal are projected to decline by 16% from 2020 to 2026 when the last of New England's coal plants is forecast to retire in both the BAU and CEI scenarios.

3.5 Carbon Emission Impacts

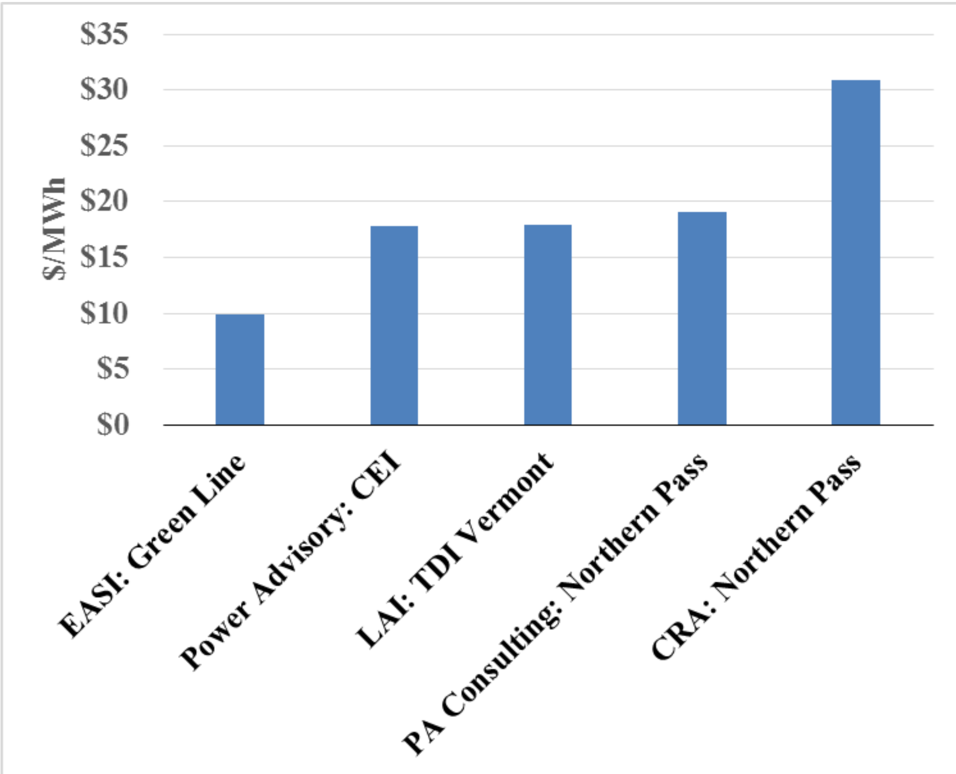
Not surprisingly, 18.9 TWh per year of CEI would also produce dramatic reductions in GHGs compared to scenarios where the region does not increase the use of clean energy beyond that called for by existing state Renewable Portfolio Standards. The simulations show that this volume of CEI would reduce regional greenhouse gas emissions by about 7.2 million metric tons per year. This reduction is equal to about 10% of the 2050 GHG reduction required by the *Massachusetts Global Warming Solutions Act (GWSA)* and would represent about 20% of the interim 2030 target that has been adopted by the New England Governor's Conference and Eastern Canadian Premiers. The *GWSA* requires an 80% reduction in GHG emissions relative to 1990 levels by 2050. In addition, Massachusetts has a mid-term goal of a 25% reduction of GHG emissions from a 1990 baseline by 2020 and 32.8% of this goal is anticipated to be achieved by the electricity sector, with 30% of the electricity sector's contribution expected from CEI.[20]

3.6 Comparison of Price Suppression Benefits

As a check on reasonableness of our modeling results, Power Advisory's analysis of the price impacts of 18.9 TWh of CEI can be compared to those produced by other studies that have quantified the price impacts of imports. For such a comparison to be meaningful, it should focus on equivalent types of savings, recognizing that different studies considered different types of savings and that our study also projected electricity fuel cost savings. In addition, it is important to consider differences in the assumed volumes of imports by presenting the savings in terms of $/MWh impact for energy imported. Figure 7 presents such a comparison to four different studies.

[20] Executive Office of Energy and Environmental Affairs, *Massachusetts Clean Energy and Climate Plan for 2020*, p. 35.

Figure 7: Project Price Suppression Benefit (2020$/MWh of Import)



The electricity sector is expected to respond to the additional supply by substantially reducing construction of CCGTs (by around 9,000 MW over the study period), increasing construction of CTs (by approximately 6,900 MW), and accelerating retirements of coal plants.

4 Net Benefits of Clean Electricity Imports

The costs and benefits of the CEI case (considering three different cost estimates) were compared to a "Business as Usual" (BAU) case. Recall that the BAU case complies with the requirements of the various state Renewable Portfolios Standards but does not make a meaningful contribution to achieving the GHG reductions required by the *GWSA*.

The benefits of the CEI case are outlined in the previous chapter. In this chapter the costs of CEI are estimated and then compared to the benefits, along with the market value of energy and capacity that would be provided by the CEI.

Recognizing the uncertainty associated with the costs of CEI and that it will be procured in a competitive process where sellers will be incented to meet "the market" may incent suppliers to accept a lower return or a longer amortization period given that these are long-lived assets. Therefore, Power Advisory developed low, base and high delivered cost estimates of the CEI to Massachusetts load centers. Three major cost components were included to arrive at the cost estimates for clean electricity imports: (1) costs of power generation; (2) costs of transmission incurred in Canada to deliver the power to the New England border; and (3) costs of transmission to deliver the power from the Canadian border to New England load centers.

4.1 Low Delivered Cost

The low delivered cost CEI scenario assumes that owners of existing Canadian hydro assets would accept New England market energy prices, net of Canadian transmission costs, and that Massachusetts customers would pay for the cost of new transmission in New England. This case is similar to the Delivery Commitment model that was employed in the Clean Energy RFP, whereby electric distribution companies (EDCs) and their customers pay for the costs of transmission to the degree that the volumes of clean energy delivered over the facilities are consistent with the volumes committed by the supplier. This cost scenario results in annual cost savings to Massachusetts consumers of $311 million per year (in 2020$).

4.2 Base Delivered Cost

The base delivered cost scenario reflects the capital and fixed operating and maintenance costs for hydroelectric generation found in the *Capital Cost Review of Power Generation Technologies*[21,22] The base delivered cost case assumes that 100% of the energy is provided by hydroelectric generation, but ultimately would likely include some wind generation. The Canadian transmission cost estimate is based on the Hydro-Quebec TransEnergie transmission tariff.

Figure 8 shows the annual net savings to Massachusetts Consumers from the CEI scenario. The Net Infrastructure Costs are the combined costs of: (1) the required generation resources; (2) transmission in Canada; and (3) transmission facilities in New England to deliver the CEI from the border with

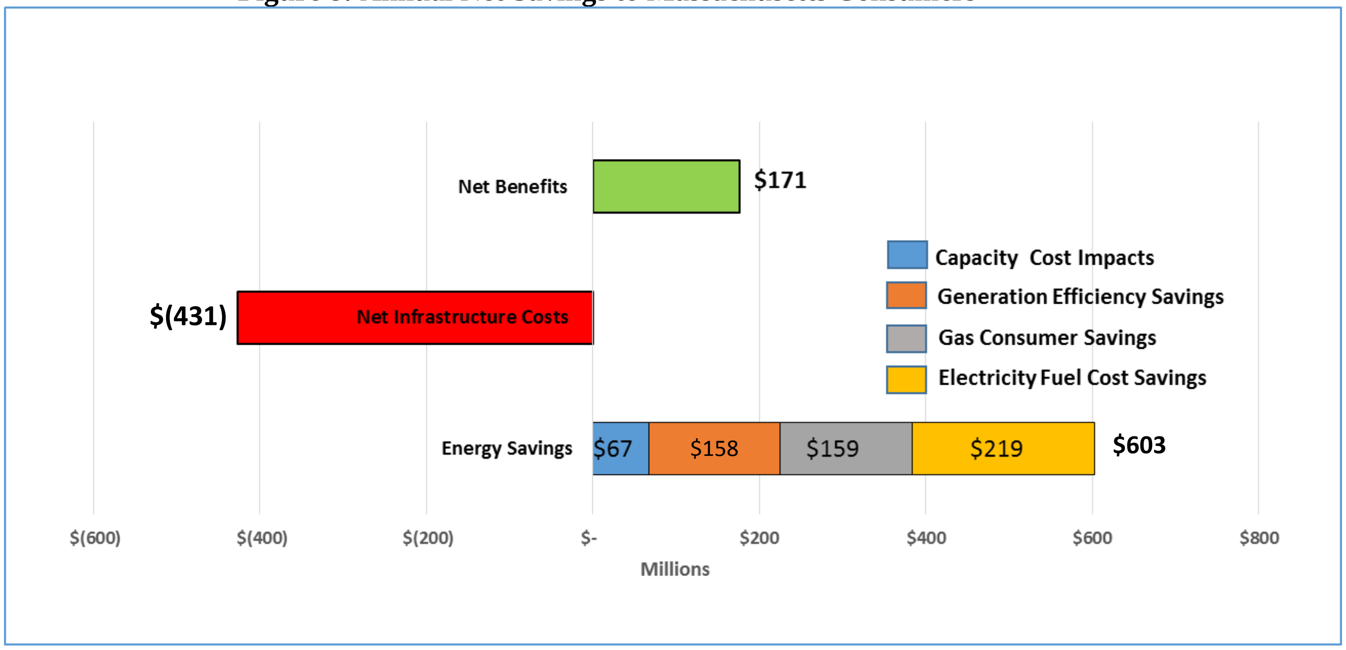
---

[21] Energy and Environmental Economics, March 2014.

[22] One of the sources considered in this report was the Assumptions to the Annual Energy Outlook, which provides a comprehensive review of the costs of a wide range of technologies. The capital cost estimates presented in the Assumptions to the Annual Energy Outlook, were generally consistent with those relied upon in the *Capital Cost Review of Power Generation Technologies*.

Canada to Massachusetts load centers, after the value of the energy deliveries (18.9 TWh per year) are considered. These Net Infrastructure Costs are then compared to the four benefits discussed above: (1) Capacity Cost Impacts; (2) Generation Efficiency Savings; (3) Gas Consumer Savings; and (4) Electricity Fuel Cost Savings. After these benefits are considered and the Net Infrastructure Costs subtracted from them, Massachusetts consumers would realize a Net Benefit of $171 million per year.

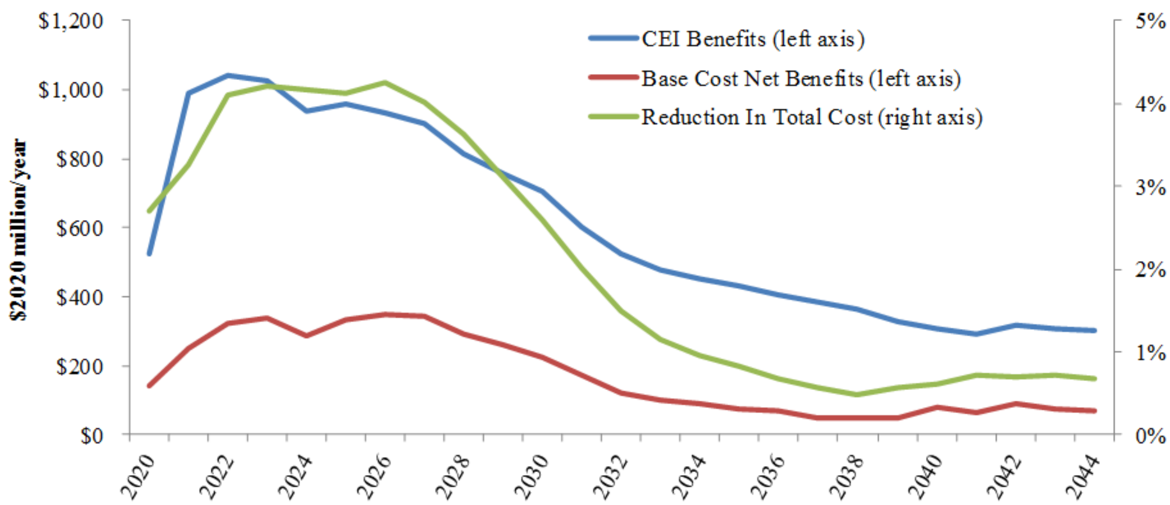
Figure 8: Annual Net Savings to Massachusetts Consumers



Source: Power Advisory

While costs and benefits have been presented as annual averages, they are not evenly distributed over time, as shown in Figure 9 below. Savings are initially high, as lower gas demand for electricity generation translate into lower gas prices in New England, and movements along the generation supply curve result in efficiency savings. The gas price savings begin to decrease around 2031, as new gas supply capacity becomes economically attractive, and completely disappear by 2041. The generation efficiency savings decrease as well, as the supply mix adjusts with less CCGT capacity and more SCGT capacity. Net benefits are therefore somewhat higher on a Net Present Value basis than the annual average figures presented would indicate.

Figure 9: Costs and Savings to Massachusetts Consumer by Year



Source: Power Advisory

4.3 High Delivered Cost

The high delivered cost scenario reflects a 25% increase in hydroelectric project costs compared to the base case and a doubling of Canadian transmission costs. These higher hydroelectric and transmission costs are mitigated by the availability of Canadian wind generation that would be cost-effective at these higher costs. In this scenario, wind generation located in Canada is assumed to provide 35% of the total electricity supplied in the high case, with hydroelectric generation providing the balance. In this scenario, Massachusetts consumers would pay an average of $116 million more than in the BAU scenario, while achieving GHG emission reductions of 7.2 million metric tonnes per year.

4.4 Production Cost Savings

The costs and benefits discussed above are from the perspective of electricity and gas consumers. Electricity producers will also experience costs and savings, which may not align with consumer costs and savings. This section quantifies production cost savings from CEI and compares them to consumer savings.

4.4.1 Gas Supplier Production Costs

The costs incurred by gas suppliers (i.e., producers, pipelines and LNG terminals) would be lower in the CEI scenario than in the BAU scenario for three reasons:

- Lower gas procurement costs due to lower gas consumption volumes;
- Lower delivery costs for existing facilities; for example, in years of higher demand, a greater share of supply would come from LNG; and
- Reduced capital and fixed operating expenditures on expanding pipeline capacity.

Power Advisory's gas market model estimates reductions in procurement costs to average $84 million/year, and delivery cost savings to average $347 million/year, based on an average reduction in gas volumes (for both electricity generation and other uses) of 105 million MMBtu/year.

As discussed above, additional gas supply capacity will be developed by 2031 in the BAU scenario and by 2041 in the CEI scenario, based on high average basis differences between Algonquin Citygate and other North American gas hubs. In total, an additional 0.7 bcf/day of pipeline capacity will be needed by 2044 in the BAU scenario, and 0.2 bcf/day in the CEI scenario, a difference of 0.5 bcf/day. The average annual cost of this additional capacity is estimated to be $76 million in the BAU scenario and $15 million in the CEI scenario, for an average savings of $61 million/year. Costs are levelized (so spread over the entire expected life of the new capacity, rather than the entire capital cost been incurred in the year of installation), and the costs are averaged over the entire 25-year study period.

4.4.2 Electricity Supplier Production Costs

Electricity supply costs will differ between the BAU and CEI scenario due to differences in

- Capacity in service, with more SCGT capacity, less CCGT capacity, and less domestic capacity overall in the CEI scenario;
- Fuel costs, including the associated GHG allowance costs, due both to lower gas prices and to the reduced need for domestic generation; and
- Variable and start costs, due to the reduced need for domestic generation.

Table 1 below shows the differences between the BAU and CEI scenario in each of these costs for each type of plant, for New England as a whole; a positive number means a production cost savings in the CEI scenario (i.e., lower costs in the CEI scenario), whereas a negative number means higher costs in the CEI scenario. Coal costs are slightly lower due to earlier retirements and lower generation in the CEI scenario. CCGT costs are lower largely due to much less CCGT capacity in service; capacity needs are largely met by SCGTs in the CEI scenario. SCGT costs are much higher for the same reason. Use of oil units is reduced slightly. The nuclear and renewable capacity in service and generation output are the same in both scenarios, so there should be no significant change in production costs.

Table 1: Production Cost Impacts

(2020$ million per year)	Fuel & GHG Allowance Savings	VOM & Savings	Capital and FOM Savings	CEI Supply Costs (Base Case)	Net Production Cost Savings
Coal	$16	$2	$1		
CCGT & Cogen	$1,750	$39	$1,038		
SCGT	-$374	-$9	-$555		
Oil Peakers	$29	$3	$0		
Total	**$1,420**	**$35**	**$485**	**-$1,561**	**$379**

Source: Power Advisory

Overall, the model estimates an average of $1.94 billion/year in fossil-fuel production cost savings. Table 1 compares this to the Base Case cost of CEI supply, including generation, transmission within Canada, and transmission within New England. (This is the gross cost; the net cost shown in Figure 8 is the gross cost minus the value of CEI on the wholesale energy market.) The net production cost savings is $379 million/year.

For comparison, consumer savings for New England electricity customers (i.e., excluding the impact of lower gas prices directly on gas consumers) are estimated to be $772 million. If $379 of this comes from production cost savings, the remaining $393 million must come from reducing electricity supplier profits. While a significant portion of the consumer savings would ultimately correspond to reductions in generator profits, the decreases in profits are not forecast to be sufficient to drive retirements, other than some coal plants which are expected to retire a few years earlier in the CEI scenario than in the BAU scenario.

Appendix A: Low Gas Price Sensitivity Case Results

The forecast of Henry Hub gas prices is a key input to Power Advisory's analysis, with almost all of our results tied to it either directly (e.g., New England gas prices, which affect gas consumers directly and are the single most important determinant of wholesale electricity prices) or indirectly (e.g., electricity capacity prices, which are in part of function of the net market revenue that CCGTs and SCGTs will earn, which in turn are in part a function of gas prices). The forecast used is taken from the Energy Information Administration's Annual Energy Outlook for 2015, and was chosen because it is from an independent and widely-relied-upon source.

In order to test the robustness of the results presented in this report, we re-ran the set of models using a significantly lower gas price, developed internally by Power Advisory and shown in Figure 2 in the main report. This resulted in a different set of electricity price forecasts, which changed the relative profitability of CCGTs and SCGTs resulting in a different supply mix, which changed gas consumption volumes for electricity production, which changed the need for and timing of gas supply improvements, which affected the New England-Henry Hub gas price basis and affected forecast electricity prices. The models were iterated as shown in Figure 1 above to find a consistent set of prices and capacity additions.

Key results from the Base (EIA Gas Price) Case and the Sensitivity (Low Gas Price) Case are shown in Table 2 below. Net benefits to Massachusetts consumers are slightly higher with lower gas prices. However, this is more than offset by the reduction in the value of the CEI due to lower wholesale electricity market prices. In the Base CEI Cost case shown in Table 2, there is still a net benefit to Massachusetts consumers, but it is smaller than in the EIA Gas Price Case. The difference of $154 million represents approximately 2% of Massachusetts consumers' wholesale energy (electricity and natural gas) costs. On the other hand, GHG emission reductions are 5% higher in the Low Gas Price Case than in the EIA Gas Price Case.

Overall, using a substantially lower gas price forecast does not significantly change this report's results and conclusions.

Table 2: Base Case and Low Gas Price Sensitivity Case Impacts On Massachusetts Consumers

(2020$ million/year)	EIA Gas Price Forecast	Low Gas Price Forecast	Difference
Impacts on MA Electricity Consumers			
Consumer Gas Costs	$159	$164	$5
Impact of Gas Prices on Electricity Prices	$219	$244	$25
Supply Curve Shift	$158	$167	$9
Capacity Price	($97)	($70)	$27
Capacity Volume	$164	$180	$16
Total Benefits to MA Consumers	**$603**	**$684**	**$81**
CEI Supply Costs			
CEI Generation and Transmission Costs	$1,561	$1,561	$0
Energy Revenue	$1,135	$900	($235)
Net Procurement Costs	**$426**	**$661**	**$235**
Net Benefit to MA Consumers	**$177**	**$23**	**($154)**
Reduction in GHG Emissions (million tonnes/year)	7.2	7.6	0.4

Source: Power Advisory