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REF: 3731-01

To: NESCOE

From: Chris Parent, Rebecca Widiss, Exeter Associates, Inc.

RE: Analysis of Carbon Pricing Impacts to the New England Power Sector

Date: Fall 2020

NESCOE engaged Exeter Associates, Inc. (Exeter) to explain the mechanics and impacts of a hypothetical, incremental price on carbon dioxide emissions (carbon pricing), provide a general assessment of carbon pricing mechanisms currently being discussed, or in effect, across North America, and assess and explain the marginal carbon price levels and emissions reduction results from recent studies. Exeter evaluated, at a high level, the impacts of carbon pricing in the New England electricity markets and analyzed the anticipated consumer cost and emissions reduction associated with a new, incremental carbon pricing mechanism using recent analyses of the ISO New England (ISONE) system and other relevant studies referenced in the Technical Appendix.

EXECUTIVE SUMMARY

There are two primary approaches to carbon pricing, Cap and Trade and Carbon Tax/Fee. Both of these approaches result in product (e.g., electricity, fuel) market prices reflecting the cost assigned to carbon. Governing bodies are responsible for determining how to handle the distribution of carbon pricing funds collected from affected parties. Other approaches can also be used to address power sector emissions.

There are two recent studies that provide perspective on the implications of an incremental carbon price in New England. One commissioned by the New England Power Generators Association (NEPGA) in 2020 determined that carbon prices ranging between $25-$35/short ton in 2025 and $55-$70/short ton in 2030 and 2035 would help to maintain sufficient progress toward the states' collective greenhouse gas (GHG) reduction standard. The second by ISO-NE in 2016 presented the results of a carbon allowance cost sensitivity analysis conducted on behalf of the New England Power Pool (NEPOOL). Based on certain scenarios, the ISO-NE analysis indicated that a change from the base price of $24/short ton to $64/short ton (incremental carbon price of $40/short ton) would add $1.9-$2.8 billion in total costs and would lower carbon emissions by an additional 2.8-8.3 million short tons annually, or 14-25%.

Exeter's analysis determines that the incremental carbon price necessary to support the investment in utility-scale solar is $45/short ton, onshore wind is $60/short ton, and offshore wind is $167-168/short ton. These levels, while eliminating or minimizing the need for mechanisms outside the wholesale markets to support these resources, could increase annual total costs to New England load (excluding pumping load and external transaction) by between $2.6-$9.7 billion. This increase, when netted against carbon pricing fees/taxes collected from emitting suppliers and refunded back to wholesale load, results in a net impact to consumers between $1.0-$3.7 billion annually.

Carbon pricing reduces system emissions: (1) through the ability to dispatch lower-emitting resources in place of higher-emitting resources;[1] and (2) over time, through investment in zero- and lower-emitting technologies that replace retiring higher-emitting technologies. While emissions impacts were not specifically assessed in this analysis, other available studies provide some perspective on the range of potential carbon emissions reductions that could result from a similar carbon price increase. Annual emissions could be reduced by 1-3 million short tons annually (3-9% reduction as compared to 2018 emissions levels) associated with dispatching lower-emitting resources for all project scenarios with a potential to reduce an additional 3-12 million short tons annually over time (9-35% reduction) depending on the amount of investment that occurs in zero- and lower-emitting technologies driven by proposed carbon price levels and growth in demand resulting from electrification of the transportation and heating sectors.[2] [3]

[1] Higher-emitting resources must increase their offers to sell electricity to reflect the cost of carbon, making lower-emitting resources lower-cost and thus dispatched ahead of the higher-emitting resources.

[2] Based on the *2016 ISO-NE Economic Study*, total emissions declined between 3-8 million short tons due to dispatching lower-emitting resources, with a $40/short ton incremental carbon price increase; however, the 2018 emissions are at 34 million short tons which is already below the level identified in three of the six scenarios which reduces the expected level carbon emissions reduction associated with dispatching lower-emitting resources.

[3] The same ISO-NE study shows incremental annual reductions in emissions ranging from 3-22 million short tons driven by the level of zero- and lower-emitting resources assumed in each scenario; however, the study does not reflect the impacts of increased demand due to electrification of transportation and heating sectors and, as previously noted, has cases in which emissions exceeded the 2018 levels. The NEPGA study from 2020, which uses carbon prices ranging from $25-$70/short ton, shows that total emissions decline from 2020 to 2035 by about 11 million short tons annually in the power sector under a scenario with high electrification in the transportation and heating sectors.

This analysis provides a simple approach to estimating the carbon price levels required to support the economic development of renewable energy projects by changing only the incremental price paid to suppliers (and charged to load) in the electricity market—thus showing the mechanics and potential impacts of the addition of a carbon price. This high-level directional assessment of an incremental carbon price mechanism to meet the particular objectives identified below is not, and should not be interpreted as, analysis appropriate to inform adjustments to the New England states' current carbon pricing mechanism, the Regional Greenhouse Gas Initiative (RGGI). When states assess that programmatic changes may be in order, they will commence a program review with associated in-depth analysis and opportunity for broad stakeholder engagement.

CARBON PRICING OVERVIEW

Assigning a cost to carbon dioxide emissions is one of the tools used in the United States, and throughout the world, as a means to represent the negative impacts of carbon emissions and to reduce power sector carbon emissions. Carbon pricing may also be applied to other carbon-intensive sectors, such as heating and transportation, or the economy as a whole. The resulting price signal provides a market-based mechanism to curb emissions through reduced consumption; investment in alternative, lower-emitting technologies; or investment in existing technologies to reduce emissions.

There are two primary approaches to carbon pricing. Both of these approaches result in product (e.g., electricity, fuel) market prices reflecting the cost assigned to carbon.

- Cap and Trade sets a limit on total carbon emissions for one or more sectors. A governing body then issues allowances (each representing a permit to emit an amount of carbon) to affected parties, either through direct allocation or an auction. These allowances are then bought or sold by companies whose emissions are over or under their limit, respectively. Thus, the price of carbon is determined by the market.
- Carbon Tax/Fee sets a carbon price based on studies of the price required to achieve a certain level of carbon reduction or the social cost of carbon (SCC).[4] This price is then applied to the emissions associated with one or more sectors. Under this approach, there is no explicit limit on emissions. However, the price of carbon can be calibrated over time to influence emissions levels.

[4] There are numerous studies on what the "right" price is for valuing carbon emissions. For example, in 2017, an international commission supported by the World Bank recommended a carbon price of between $44-$88/short ton by 2020 and $55-$110/short ton by 2030 to meet the Paris Agreement (see link, values converted from metric tons). These ranges comport with carbon values selected by Synapse and Brattle for recent carbon pricing studies focused on New England (see link and link).

Governing bodies, such as, for example, state government agencies or their representatives, determine how to handle the distribution of carbon pricing funds collected from affected parties. Judgements about how to distribute funds are often based on policy preferences. Carbon pricing funds are commonly used to fund environmental/efficiency programs that reduce emissions or to provide consumer rebates that mitigate cost increases (e.g., higher electricity bills).

Carbon pricing can affect power sector emissions through both short- and long-term economic substitutions by:

- Changing Dispatch Order. Carbon prices may make higher-emitting resources more expensive than lower-emitting alternatives, thus causing the latter to be used more frequently to provide energy.
- Changing the Resource Mix. Carbon prices may reduce potential revenues from higher-emitting technologies (i.e., less energy provided and lower net price) and increase potential revenues for lower- and zero-emitting technologies (i.e., more energy provided at higher net price) over time, promoting investment in lower- and zero-emitting technologies and investment in (e.g., retrofitting existing oil/coal resources for natural gas or installing new, more efficient gas turbines) or retirement of higher-emitting technologies.

The impact of carbon pricing on power sector emissions is highly dependent on the price of carbon, the resource mix in a given region, and long-term expected load growth.

COMPLEMENTARY MECHANISMS

Carbon pricing is not the only tool used to address power sector emissions. Other approaches include fuel taxes, the removal of fossil fuel subsidies, and payments for emissions reductions or offsets. Alternatively, numerous state and federal programs provide direct support for lower- or zero-emitting generation technologies. The most widely utilized state programs include Renewable Portfolio Standards (RPS) and Clean Energy Standards (CES), which require that a certain percentage of a state’s electricity come from lower- or zero-emitting sources. Long-term contracts are also used to meet a portion of state RPS/CES requirements. Federal programs establishing targeted tax credits/benefits (e.g., federal production and investment tax credits) have also promoted the development of new lower- or zero-emitting sources.

CARBON PRICING IN NORTH AMERICA

Table 1 provides a summary of carbon pricing approaches that have been implemented or are actively being discussed across North America. Additionally, there are numerous carbon-related bills being considered by the U.S. Congress in its current session.[5]

Table 1. Carbon Pricing in North America

Locations	Program Type	Status	Sectors Impacted	Price ($ U.S./short ton)
CT, DE, MA, MD, ME, NH, NJ, NY, PA,[1] RI, VA,[2] VT	Cap & Trade	Implemented	Power	$5-6 in 2020
MA	Cap & Trade	Implemented	Power	$7-8 in 2019
CA	Cap & Trade	Implemented	Power, Industry, Transportation	$21 in 2020
OR[3]	Cap & Trade	Pending	TBD	TBD
NY	Tax	Under discussion	Power	$47 in 2020[4] $69 in 2030[4]
WA	Cap & Trade	Pending	Power & Other Stationary Sources	TBD
CANADA[5]	Tax	Implemented	Fuel	$41 in 2022
	Cap & Trade		Industry	Unknown

[1] Pennsylvania is currently considering joining the Regional Greenhouse Gas Initiative (RGGI).

[2] Virginia is scheduled to join RGGI on January 1, 2021.

[3] Oregon lawmakers opposed to a cap-and-trade rule have prevented a final vote on enabling legislation in both 2019 and 2020. A subsequent Executive Order to reduce greenhouse gas (GHG) emissions has been challenged in court.

[4] The New York PSC will determine an SCC if key stakeholders and the New York Independent System Operator (NYISO) Board approve the concept of carbon pricing. The prices shown here reflect SCC levels consistent with values used by the PSC to date.

[5] Canada allows provinces and territories to use their own carbon pricing systems, provided they meet a federal benchmark. All other provinces and territories are subject to a national fuel charge and a carbon trading system for large industry.

Sources: S&P Global Market Intelligence (RGGI, CA); ISO-NE Market, Monitor (MA), link; NYISO (NY), link; Canada.ca (Canada), link, link.

RECENT STUDIES SPECIFIC TO NEW ENGLAND

There are two recent studies that provide perspective on the implications of a new, incremental carbon price in New England. In June 2020, the Analysis Group released the results of a study commissioned by the New England Power Generators Association (NEPGA) and in April 2017, the Independent System Operator of New England (ISO-NE) presented the results of

[5] Carbon Pricing Proposals in the 116th Congress, http://priceoncarbon.org/wp-content/uploads/2020/03/116th-Leg-Table.jpg.

a carbon allowance cost sensitivity analysis conducted on behalf of the New England Power Pool (NEPOOL). These studies demonstrate both of the economic properties of carbon pricing by using models that changed the dispatch order and resource mix over time to evaluate the long-term effects of a carbon price on the power sector.

2020 NEPGA Carbon Pricing Study for New England

This study determined that carbon prices ranging between $25-$35/short ton in 2025 and $55-$70/short ton in 2030 and 2035 would help to maintain sufficient progress toward the states' collective greenhouse gas (GHG) reduction standards while reducing reliance on long-term contracts.[6] As illustrated in Figure 1, carbon pricing—*in conjunction with rapid electrification of the heating and transportation sectors, increased energy efficiency, and increased reliance on storage and zero-emissions resources*—was projected to reduce regional emissions by 53.5 million metric tons (59 million short tons) in 2035, relative to the study's base case, which reflects emissions reductions due solely to *planned* renewable resource additions. According to the Analysis Group, the "introduction of a carbon price in the power sector would increase wholesale electricity prices, but would not drive up consumers cost materially if states choose to rebate carbon revenues."[7] Notably, this study did not quantify the change in wholesale prices or the sum of carbon revenues available to be rebated.

[6] For reference, under the marginal emissions rate assumed for wholesale load in this analysis, the NEPGA study's carbon price estimates are approximately $12-$16/MWh in 2025 and $26-$33/MWh in 2030 and 2035.

[7] NEPGA Carbon Pricing Study at 28.

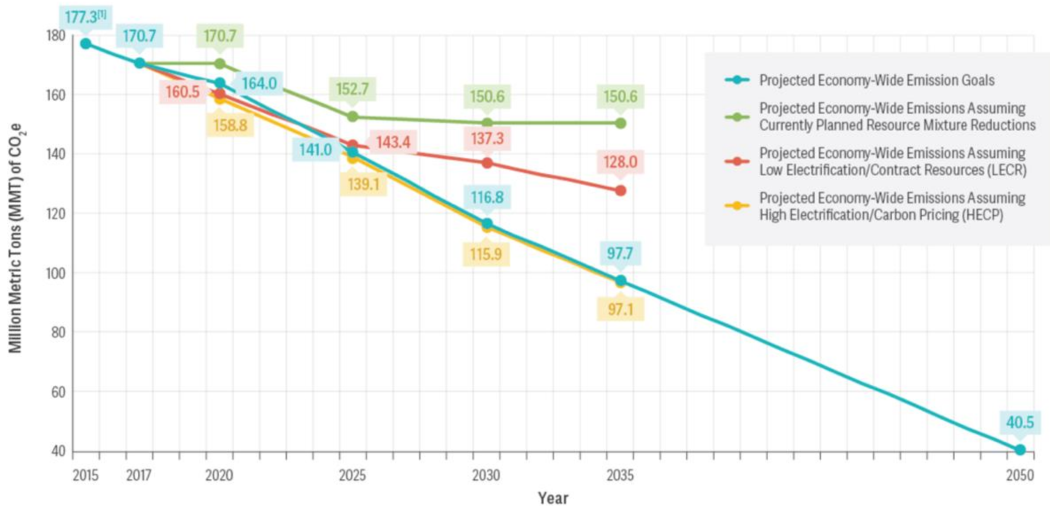


Figure 1. New England Emission Reduction Goals Compared with Projected Reductions Due to: (1) Planned Renewable Resource Additions; (2) Such Additions with Increased Electrification; or (3) Such Additions with High Electrification and Carbon Pricing

Source: Joseph Cavicchi and Paul Hibbard, *Carbon Pricing for New England: Context, Key Factors, and Impacts*, Analysis Group, June 2020, (NEPGA Carbon Pricing Study) https://www.analysisgroup.com/globalassets/insights/publishing/2020-june-analysis-group-carbon-pricing-for-ne-main-report.pdf.

2016 ISO-NE Economic Study: Carbon Allowance Cost Sensitivity for New England

This study simulated six "base" scenarios for the year 2030, each of which involved fulfilling New England state RPS requirements and replacing natural gas retirements in New England through different combinations of new resources and, in some cases, alternative compliance payments. The scenarios were simulated with a base carbon price of $24/short ton and $64/short ton.[8] Figure 2 shows the resulting carbon emissions. Depending on the scenario, a carbon price of $64/short ton lowered carbon emissions by 2.8 to 8.3 million short tons, or 14-25%, relative to the base price of $24/short ton. In this study, the carbon prices result in changes to the dispatch order, based upon that scenario's assumed resource mix.

[8] For reference, under the marginal emissions rate assumed for wholesale load in this analysis, the 2016 ISO-NE study's $24/short ton and $64/short ton carbon price assumptions are approximately equal to $11/MWh and $30/MWh, respectively.

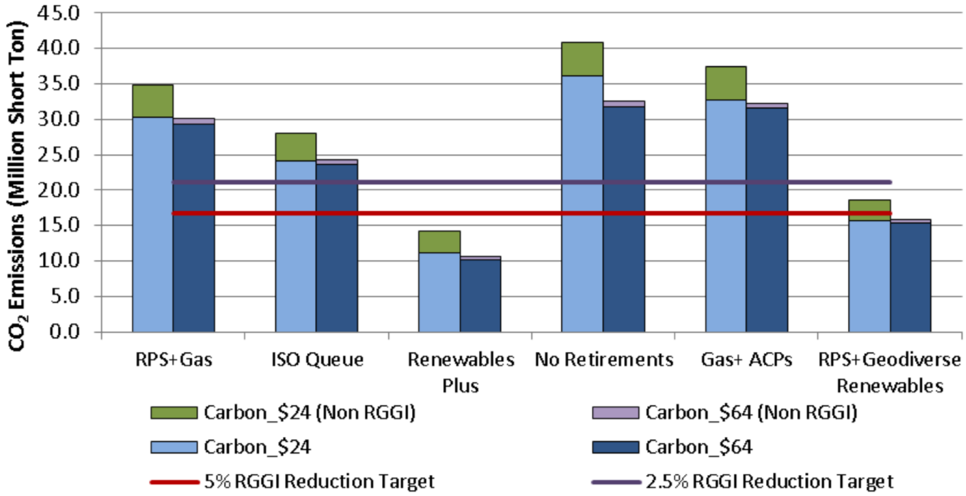


Figure 2. Annual New England Power Plant CO_2 Emissions in 2030, Transmission Constrained

Source: 2016 Economic Study: Carbon Allowance Cost Sensitivity Draft Results, ISO-NE, April 2017, https://www.iso-ne.com/static-assets/documents/2017/04/a6_2016_economic_study_carbon_cost_.pdf.

ISO-NE's sensitivity analysis also evaluated the impact to load-serving entity (LSE) electricity market and uplift costs.[9] Depending on the scenario, Figure 3 shows a carbon price of $64/short ton increased the combined electricity market and uplift costs by $1.9-$2.8 billion, or 32-33%, relative to the price of $24/short ton. Combined, the scenarios show that a $1.9-$2.8 billion cost would lower carbon emissions by an additional 2.8- 8.3 million short tons, or 14-25%. The ISO-NE study did not include any estimate of the carbon tax charged to emitting power plants or the total carbon tax disbursement fund available to be used as an offset to the increased costs.

[9] Uplift refers to payments that power plants receive when prices do not fully compensate them for following reliability dispatch instructions from ISO-NE.

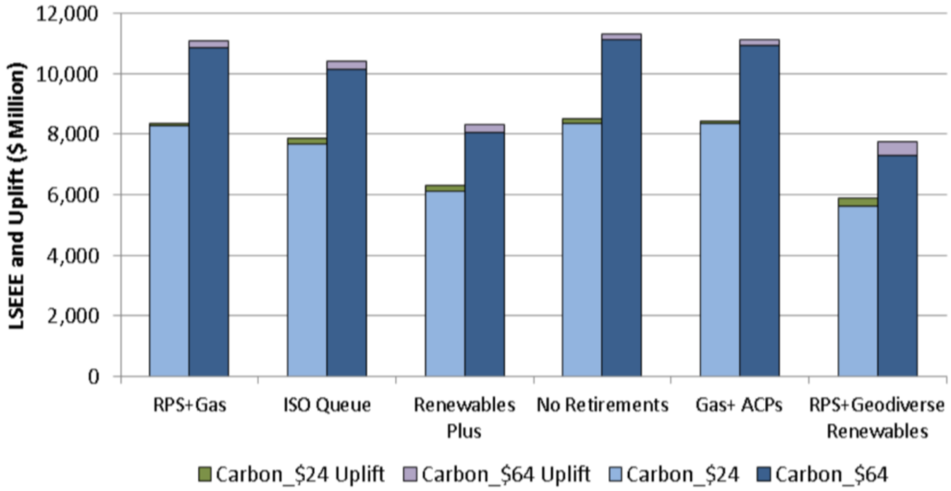


Figure 3. Annual New England LSE Energy Cost in 2030, Transmission Constrained

Source: 2016 Economic Study: Carbon Allowance Cost Sensitivity Draft Results.

EXETER ECONOMIC ANALYSIS OF THE CARBON PRICE REQUIRED TO SUPPORT ECONOMIC DEVELOPMENT OF ZERO-EMITTING TECHNOLOGIES

This high-level economic analysis seeks to better understand the impacts to the New England region of adding an incremental carbon price in the power sector to promote investment in zero-emitting technologies.[10] To that end, this analysis estimates the carbon prices that would be required to increase electricity market prices to levels that would support the economic development of utility-scale solar (20 MW nameplate), onshore wind (82.5 MW), and offshore wind (800 MW) under various cost assumptions,[11] without the need for long-term contracts or other non-market payments beyond what is currently in place (i.e., renewable energy certificates [RECs]). Two scenarios, one for onshore wind and one for offshore wind, include additional transmission costs to ensure that power can be delivered to loads in New England.

For each of the five scenarios, a carbon price is established that is estimated to provide sufficient annual incremental electricity market revenue—in addition to existing electricity market revenue, RECs, and an assumption of $2/kW-month in capacity market revenues—to

[10] This high-level directional assessment of an incremental carbon price mechanism to meet the particular objectives identified below is not, and should not be interpreted as, analysis appropriate to inform adjustments to the New England states' current carbon pricing mechanism, RGGI. When states assess that programmatic changes may be in order, they will commence a program review with associated in-depth analysis and opportunity for broad stakeholder engagement.

[11] The addition of a carbon price raises the electricity market price in many hours because resources setting the price in the electricity market are often carbon-emitting and must increase their supply offers to cover their anticipated cost of carbon. The hypothetical new resources in this analysis are based upon Concentric Energy Advisors and Mott MacDonald's preliminary analysis of the Cost of New Entry for 2025-26 (the capacity commitment period associated with forward capacity auction #16).

cover the given technology's costs over the 20-year life of each project. This incremental carbon price is then used to estimate the economic impacts to the New England wholesale electricity markets including the incremental costs to load, incremental payments to supply, incremental carbon tax applied to carbon-emitting supply, the overall carbon tax distribution fund level, and then using other studies' estimates a potential range of impacts to emissions.

The analysis uses 2018 historical data to establish a baseline for electricity production, consumption, and associated emissions in the future. The economic analysis assumes that over the life of each project scenario: (1) the marginal emissions rate and average emissions rate by technology remain unchanged;[12] (2) the incremental carbon price has no impact on how the system is dispatched, rather uniformly shifting the portion of the supply curve up which is setting the electricity price; and (3) the resource mix on the system remains unchanged. Therefore, this simple economic analysis does not show a change to the total emissions on the system. In reality, over the 20-year life of these projects, the total system emissions would likely decline as more electricity is produced from lower- and zero-emitting technologies driven by the level of investment in these technologies. However, increases in consumption resulting from the electrification of the transportation and heating sectors would also put upward pressure on power sector emissions for the New England region depending on how the resource mix evolved.

Carbon Price Increases Costs to Load

Under the least expensive resource type scenario analyzed (utility-scale solar), an incremental carbon price is estimated to increase electricity market costs (for wholesale load, pumping load, and export transactions) annually by $2.7 billion. Carbon pricing revenue collected from suppliers and rebated to load could be used to reduce these costs by $1.7 billion, resulting in a net impact to all load of $1.0 billion.[13] For resource-type scenarios with higher annual revenue requirements to cover costs, the carbon price increases significantly, as do the annual costs.

Table 2 provides a summary of the results, showing a net impact to all load (including pumping load and export transactions) ranging from $1.0-$3.8 billion annually. Exeter also ran a

[12] The all-hours marginal emissions rate (for 2018) used in this analysis is 916 lbs/MWh or a natural gas machine heat rate of 7.83 MMBtu/MWh. Exeter used this emissions rate since it aligned with the current resource mix, so better matched the underlying average emissions rates used to determine the carbon tax for emitting supply. Reducing the marginal emissions rate increases the carbon price, while increasing the marginal emissions rate reduces the carbon price; however, overall costs should remain about the same since the electricity market price paid to suppliers and charged to load remains unchanged.

[13] For reference, wholesale electricity market costs in 2018 were approximately $9.8 billion. A net impact to load of $1.0 billion resulting from a hypothetical new, incremental carbon price would approximately equal a 10% increase in wholesale market costs in one year.

sensitivity analysis with a higher assumption for capacity revenues (i.e., $4/kW-mo) that reduced the net impact to load by $0.1-$0.2 billion.

Table 2. Incremental Carbon Price Impact Summary Results, by Scenario

Scenario	Incremental Carbon Price ($/short ton)[1]	Electricity Price Increase for Load ($/MWh)	Incremental Costs ($ billions)	Carbon Tax Disbursement Fund ($ billions)	Net Impact to Load ($ billions)
Utility-Scale Solar	$45	$21	$2.7	$1.7	$1.0
Onshore Wind [2] (Load Deliverable)	$60	$28	$3.6	$2.2	$1.4
Offshore Wind	$167	$78	$9.9	$6.1	$3.8
Offshore Wind (Load Deliverable)	$168	$78	$10.0	$6.2	$3.8

[1] All analysis is based on 2025 U.S. dollars.

[2] Without considering the cost of ensuring that onshore wind could be deliverable to major load centers in New England, onshore wind was determined to be economic, even without an incremental carbon price.

Table 3 provides a breakdown of total costs by state and scenario (excluding pumping load and export transactions) based on the 2018 annual load ratio share.[14]

Table 3. Costs by State and Scenario ($ millions)

Scenario	VT	RI	ME	NH	CT	MA	**Total**
Utility-Scale Solar	$115	$170	$244	$246	$625	$1,173	**$2,572**
Onshore Wind (Load Deliverable)	$154	$228	$327	$330	$839	$1,573	**$3,451**
Offshore Wind	$428	$633	$909	$918	$2,334	$4,377	**$9,600**
Offshore Wind (Load Deliverable)	$431	$638	$916	$925	$2,351	$4,409	**$9,670**

Carbon Price Reduces Emissions

While this economic analysis did not specifically evaluate how a carbon price impacts system emissions, other available studies for New England provide a point of comparison. Based on these studies, Exeter approximates that the carbon prices proposed in this analysis could result in a decrease in annual carbon emissions related to dispatching lower-emitting resources in place of higher-emitting resources of about 1-3 million short tons (3-9% reduction as compared to 2018 emissions levels) with an additional 3-12 million short ton reduction annually (9-35% reduction) occurring over time, depending on the level of investment driven by the proposed carbon price and other mechanisms to support renewable and clean energy resources, and the impacts to demand of the electrification of the transportation and heating sectors.

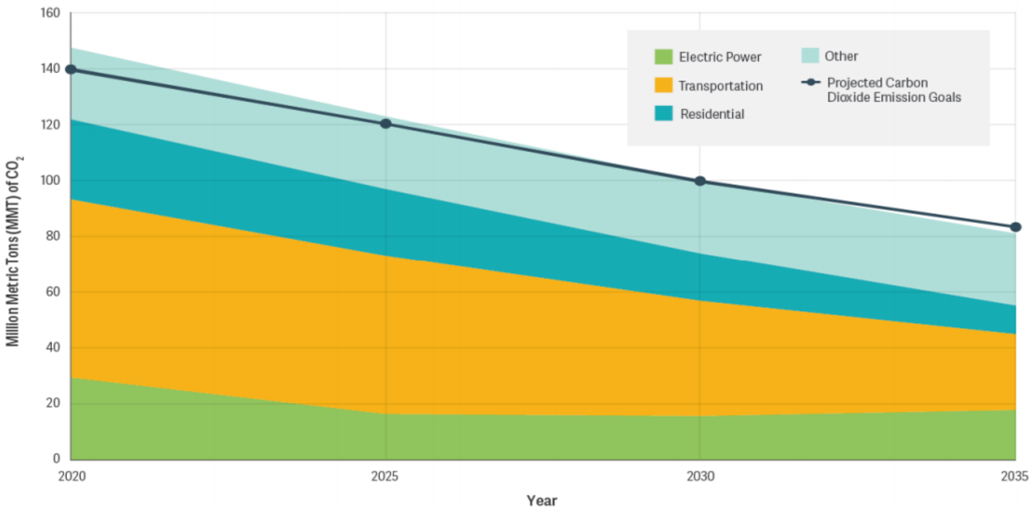
[14] This does not reflect any reduction in costs associated with the portion of the carbon tax disbursement fund that would be allocated to the wholesale load.

Figure 2 above (from the *2016 ISO-NE Economic Study*) shows the potential reduction in emissions that could occur related to both dispatching lower-emitting resources with a higher carbon price and if investment is made at various levels of lower- and zero-emitting resources.

- This shows a reduction in annual emissions ranging from 3-8 million short tons related to dispatching lower-emitting resources generally resulting from increasing natural gas generation and reducing coal, oil, and biomass/refuse generation.[15]
- The other scenarios in this study provide examples of how different resource mixes would impact total emissions, ranging in reductions of 4-22 million short tons annually, relative to the 'No Retirements' scenario (which most closely resembles the 2018 actual system underlying the Exeter analysis). The reduction in carbon emissions would be a function of the level investment in lower- and zero-emitting technologies driven by (1) the proposed carbon price, with higher carbon prices resulting in greater emissions reductions, and (2) other mechanisms to support renewable and clean energy resources. However, this study does not reflect the potential significant impacts to demand of electrification of the transportation and heating sectors.

Figure 4 (from NEPGA's 2020 carbon pricing study) provides some context as to how increased electrification of heating and transportation sectors could impact New England economy-wide emissions. According to NEPGA's analysis, *reductions in power sector emissions are modest* over time and begin to increase again as 2035 approaches, even with installation of lower- and zero-emitting resources, with an overall net decline of about 11 million short tons in the power sector over the 15-year period. As shown in Figure 4, most of the economy-wide carbon emission reductions would likely come from the transportation sector.

[15] Carbon emissions levels for 2018 were around 34 million short tons. Three of the cases in the *2016 ISO-NE Economic Study* have emissions levels with hypothetical future resource mix in the year 2030 that are above 2018 emissions levels, ranging from 35-41 million short tons.



Notes:

[1] Economy-wide emission reduction goals are determined by aggregating each New England state's historical emissions by sector and annual GHG emission targets. If data is unavailable for a given year in a state, the goal is estimated by interpolating results from years where it is available. The carbon-specific emission goal is estimated by using historical data on the share of total GHG emissions derived from carbon emissions.

[2] Power generation adjustments include higher levels of electrification, the retirement of fossil-fuel plants, the addition of renewable resources, additional energy efficiency, and a $25/short ton price on carbon in 2025, $65/short ton in 2030, and $70/short ton in 2035.

[3] Electrification assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating. It also assumes 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles.

Figure 4. Projected CO_2 Emissions Changes by Sector: High Electrification

Source: Joseph Cavicchi and Paul Hibbard, *Carbon Pricing for New England: Context, Key Factors, and Impacts*, Analysis Group, June 2020, https://www.analysisgroup.com/globalassets/insights/publishing/2020-june-analysis-group-carbon-pricing-for-ne-main-report.pdf.

EXETER DETAILED ANALYSIS RESULTS

CARBON PRICE IS DRIVEN BY REVENUE REQUIREMENT AND ENERGY PRODUCTION

Figure 5 shows that incremental carbon prices range to meet the annual required revenue requirement by resource type from $45/short ton (utility-scale solar scenario) to $168/short ton (offshore wind scenario), resulting in increases in the electricity market prices of $21/MWh to $77/MWh.[16] These results are comparable with modeling conducted by The Brattle Group on behalf of NYISO Integrating Public Policy Task Force (IPPTF); namely, a carbon price of $49/short ton raised wholesale electricity market prices in New York by $17.90/MWh.[17]

[16] The average increase in electricity market prices is different by resource type, load category and external interface due to the different weighted, marginal emissions rates used for each group in the analysis. Exeter calculated a unique MW-weighted marginal emissions rate per external interface, generation fuel type and load category using the hourly marginal emissions data published by ISO-NE for 2018 and adjusted to better reflect the impact of a carbon price on pumped-storage facility bidding. *Source:* ISO-NE, *2018 ISO New England Electric Generator Air Emissions Report*, May 2020.

[17] The Brattle Group on behalf of NYISO Integrating Public Policy Task Force, "Carbon Charge Customer Cost Impact" (scenario results and abatement detail tabs), November 28, 2018.

These carbon and electricity market prices are a function of each technology's annual revenue requirement (based on ISO-NE's most recent publication of these technologies' annualized costs and revenues)[18] and annual energy production.[19] In the case of offshore wind, a significant gap between annualized costs (assumes $1.5 billion in transmission costs) and revenues drives the carbon price ($168/short ton) and associated incremental electricity market price ($77/MWh) relatively high compared to other scenarios.[20]

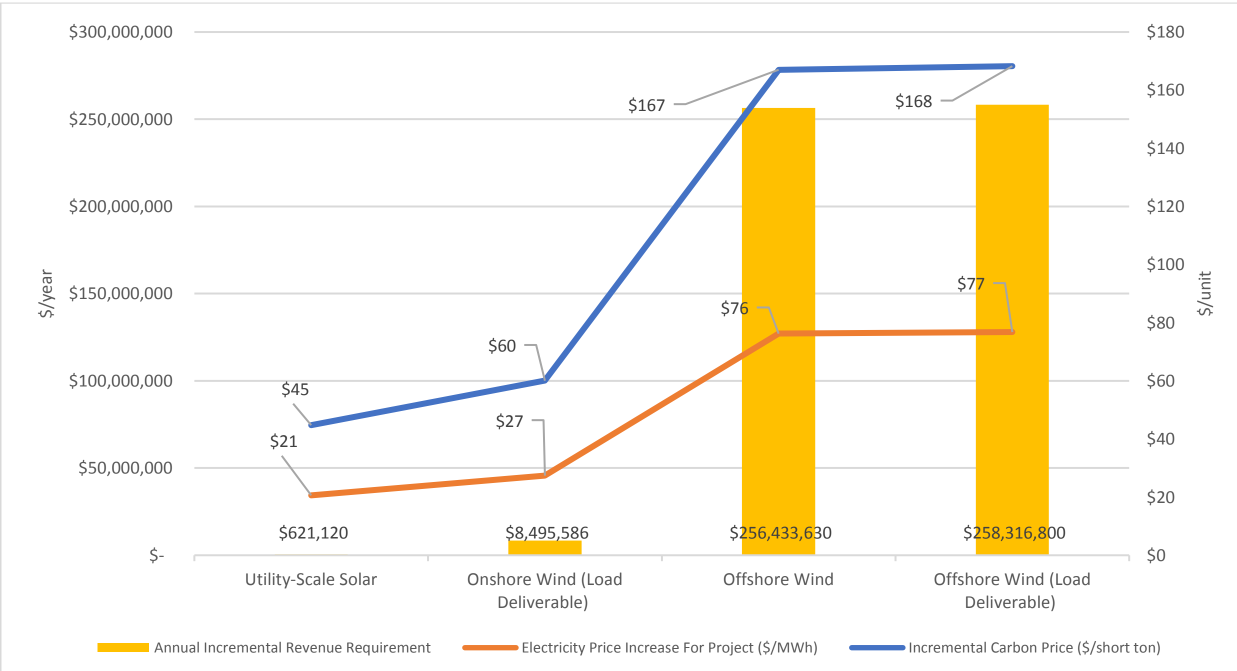


Figure 5. Annual Revenue Requirement and Incremental Energy and Carbon Prices, by Scenario

LOWER- AND ZERO-EMITTING TECHNOLOGIES BENEFIT FROM THE CARBON PRICE

The carbon price (as reflected in electricity market prices) results in an increase in revenues to suppliers with lower- or zero-emitting technologies (including nuclear, solar, wind, hydropower, and import transactions from other control areas and more efficient natural gas resources), while higher-emitting technologies are charged for much or all incremental payments through the carbon tax (creating the source for the carbon tax disbursement fund). The net supplier

[18] The onshore wind scenario includes a proxy for costs of upgrading transmission to make the project deliverable to load in southern New England of $139.6 million (2019$) in installed costs associated with 82.5 MW of an HVDC line installation. This was developed based on a New England State Committee on Electricity (NESCOE) study in 2017. *Source:* NESCOE, *Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study*, Phase I: Scenario Analysis, Winter 2017, p. 57.

[19] ISO New England, NEPOOL Markets Committee, Agenda Item #4, August 11-13, 2020.

[20] The $1.5 billion in transmission costs for interconnecting offshore wind resources is from Concentric Energy Advisors and Mott MacDonald's preliminary analysis of the Cost of New Entry for 2025-26 (the capacity commitment period associated with forward capacity auction #16).

settlement in Figure 6 reflects the incremental revenues that would be earned by lower- or zero-emitting technologies.

The incremental payments to suppliers or gross cost to load (ranging from $2.7-$10.0 billion annually) and the tax charged back to emitting technologies (ranging from $1.7-$6.2 billion annually), with the net supplier settlement or cost to consumers[21] ranging from about $1.0-$3.8 billion annually, this reflects the total gross payments minus the carbon tax reimbursement on carbon emissions are shown in Figure 6 by resource type. The *ISO-NE 2016 Economic Study* used a similar increase in the assumed carbon price ($40/short ton) as the utility-scale solar (compared to $45/short ton in this analysis), and the incremental electricity costs for supporting utility-scale solar of $2.7 billion are in the range of the $1.9-$2.8 billion cost increase published in the ISO-NE study. Accordingly, Exeter's results are comparable to the *ISO-NE 2016 Economic Study's* findings .

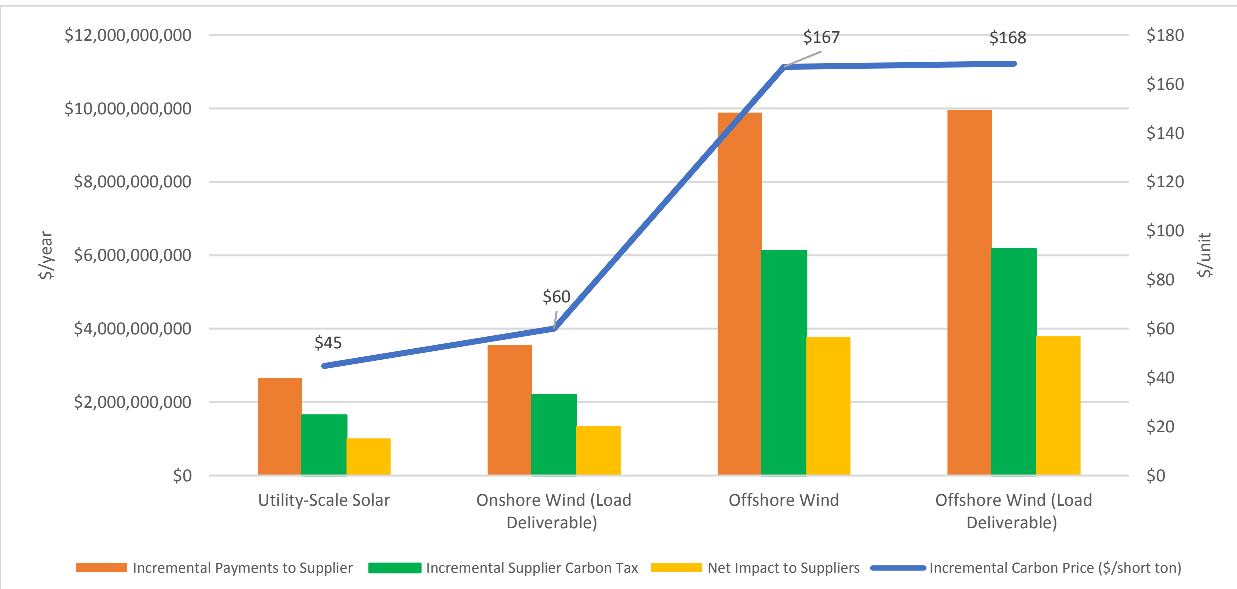


Figure 6. Net Supplier Impact of Carbon Price, by Scenario

[21] This assumes that all fees/taxes collected from emitting suppliers are credited back to consumers.

ELECTRICITY COSTS INCREASE IN LINE WITH INCREASES IN PAYMENTS TO SUPPLIERS

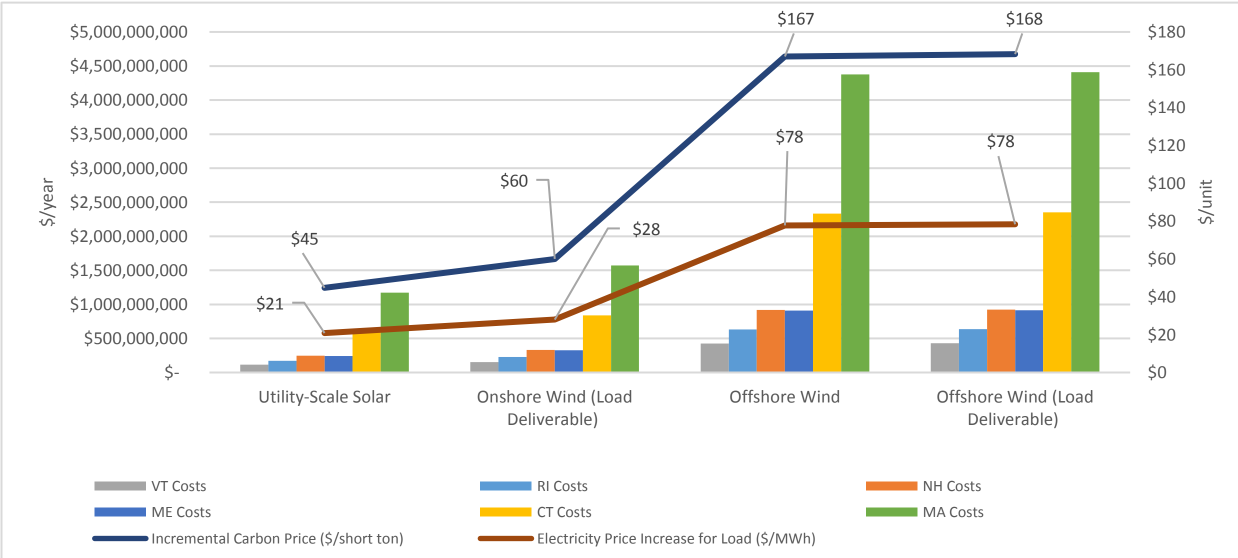


Figure 7 provides a breakdown of costs by state (based on the annual load ratio share and exlcuding pumping load and export transactions) as compared to the incremental carbon price and incremental energy price paid by load. These costs mirror the total payments made to suppliers, ranging from $2.6-$9.7 billion annually .

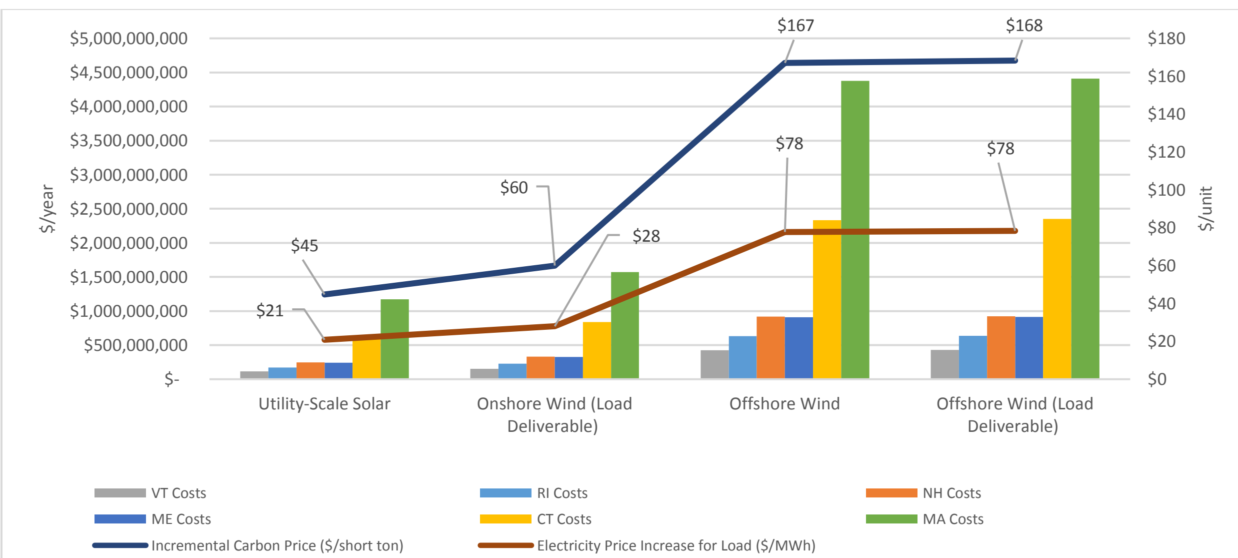


Figure 7. Incremental Costs from Carbon Price by State and Scenario

MATERIAL NET CONSUMER COSTS REMAIN EVEN WHEN THE CARBON TAX DISBURSEMENT FUND IS USED TO OFFSET THE INCREMENTAL COST

While total cost increases mirror the payments, and these costs can potentially be largely offset by the carbon tax collected from suppliers depending on the allocation mechanism selected, material net costs related to the carbon price are still charged to consumers. Figure 8 shows the net impact of fully rebating carbon tax revenues back to all load to be between $1.0-$3.8 billion in incremental annual costs. This is a 62% reduction in each scenario from the total costs, leaving 38% of costs that would not be offset.

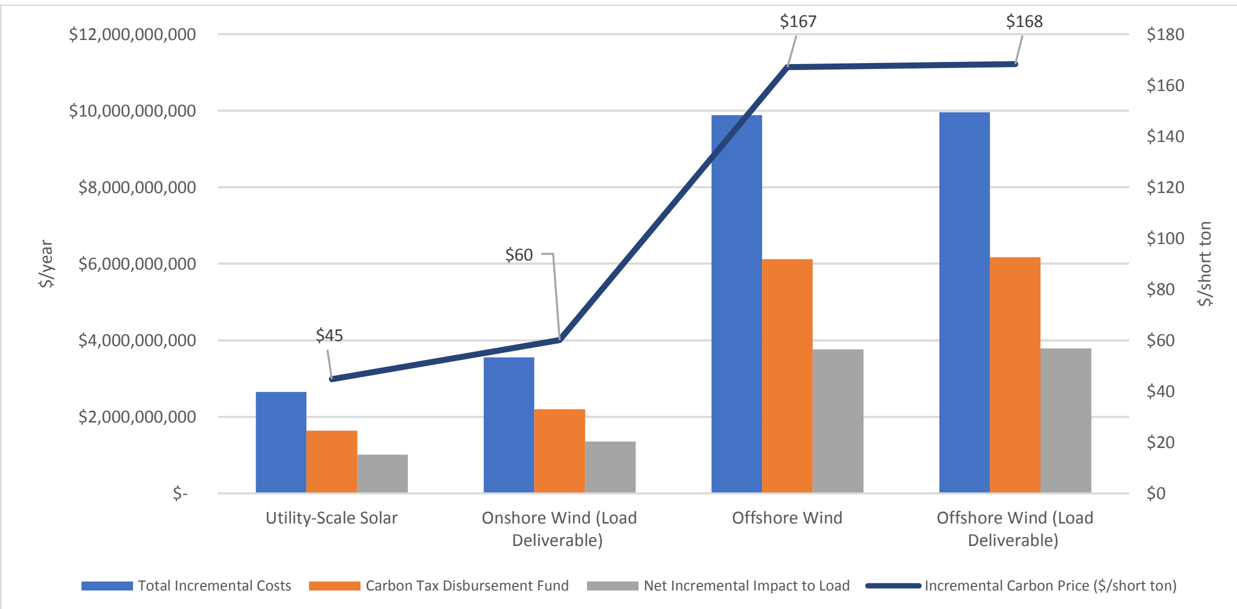


Figure 8. Net Impact to Wholesale Load, Pumping Load, and Export Transactions of Carbon Price, by Scenario

TECHNICAL APPENDIX

Note: This technical appendix provides details on the approach used in the analysis, key assumptions, how various calculations are performed and the source data being used for the analysis.

APPROACH

This analysis uses a simplified approach to estimate the potential costs of the addition of an incremental carbon price set at a level that would enable utility-scale solar and onshore and offshore wind (under different transmission cost assumptions) to be developed economically without support of long-term contracts.[22] This analysis only changes the incremental price paid to suppliers and charged to load in the electricity (or energy) market (effectively holding all other variables constant over the life of these projects), allowing for the mechanics and potential impacts of the addition of a carbon price to be demonstrated in a straight-forward manner.

This was done by (1) calculating an annualized revenue shortfall for each identified scenario which would have to be recovered through an incremental carbon price being reflected in the electricity market prices; (2) calculating the associated impacts to electricity market payments to suppliers and charges to load servers; (3) calculating the carbon tax charged back to emitting-supply resources and the associated aggregate carbon tax disbursement fund; and (4) the directional impacts of an incremental carbon price to the net cost of new entry (CONE) resources.

Key Assumptions

The following simplifying assumptions were used for this analysis:

- 2018 calendar year data are the basis for the production, emissions, and consumption profile, and analysis is performed using aggregated annual data.
- Only those generation technologies participating in the New England electricity markets directly as supply resources are included in the analysis (i.e., excludes all behind-the-meter generation impacts when assessing carbon tax).
- Assumptions around costs and revenues are based on ISO-NE's most recent proposed offer review trigger price (ORTP) models.

[22] Financing certain renewable energy projects without long-term contracts has been challenging, but for purposes of this analysis it is assumed that a carbon price with expected electricity market revenues would provide adequate certainty to support financing these projects.

    - Historical (2017-2019) energy and REC price revenues (adjusted for inflation) are used to determine revenues over the life of the project.
    - Project life is assumed to be 20 years for all technologies.
    - Incremental transmission costs were provided by NESCOE staff.
- Incremental carbon price does not change the real-time dispatch results, real-time energy, or REC prices or the resource mix over time and thus cannot simulate changes to total emissions levels.
    - Analysis does not show how an incremental carbon price would impact dispatch and the resource mix over time.
    - Analysis focuses only on real-time and did not evaluate the day-ahead market implications of impacts of the new day-ahead reserve products.
- Changes in revenues resulting from the carbon price are constant (levelized) over the life of the project.

EMISSIONS RATES

Since the analysis is being performed on an annual basis, it is not possible to estimate the hourly marginal emissions, so an approach needed to be developed to establish appropriate emissions rates to use for purposes of estimating the incremental payments and charges (marginal emissions rate) and carbon tax (average emissions rate).

Marginal Carbon Emissions Rates

One of the critical inputs to this analysis is the appropriate marginal emissions rate for determining both the necessary carbon price for the identified project scenarios to recover their costs and the rate paid to suppliers and charged to load servers.[23] Three different options were examined for determining the marginal emissions rate with a goal of calculating representative system marginal emissions rates for external interfaces (export and import transactions), wholesale load, pumping load, and generation (by fuel type).

OPTION 1: NATURAL GAS-BASED EMISSIONS RATE

Since natural gas resources are generally on the margin in New England, Exeter considered using an average natural gas generation heat rate to calculate the marginal emissions level.

[23] This is the emissions rate associated with the resource(s) that are setting the electricity market price (or locational marginal price) in the wholesale electricity markets.

Figure 1 shows the supply curve for the New England system and minimum and maximum load to provide some context for different fuel types and where they show in the supply curve.[24]

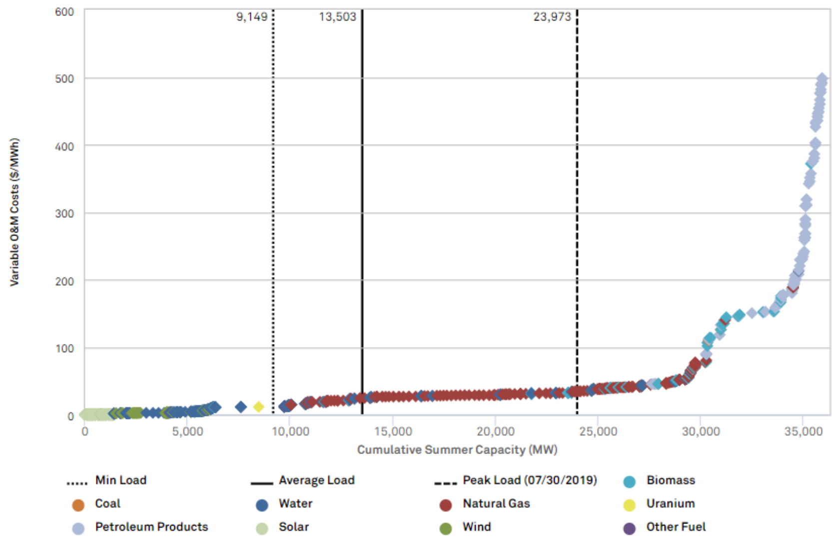


Figure 9. Summer Generic New England Supply Curve (S&P Global 2019 data)

Exeter reviewed multiple data sources to determine an appropriate heat rate for the natural gas resource mix in New England.

- The weighted generation production average using hourly S&P Global hourly generation data from 2018 of 7.399 MMBtu/MWh.
- The weighted generation capacity average of 7.373 MMBtu/MWh using the full-load heat rates published for the 2016 Net CONE/ORTP review.[25]

Using this information, Exeter selected a heat rate of 7.4 MMBtu/MWh with a calculated marginal emissions rate of 867 lbs/MWh.[26] This emissions rate would be applied universally to all hours, external interfaces (exports and imports), wholesale load, pumping load, and generation (by fuel type), so is not able to have differentiated marginal emissions rates by group.

OPTION 2: ISO-NE 2018 MARGINAL EMISSIONS RATES

ISO-NE publishes marginal, system-wide, load-weighted marginal emissions rates for the region, most recently in 2018. The load-weighted emissions approach provides a reasonable value that

[24] Natural gas generation was on the margin in 73% of the pricing intervals. Source: ISO-NE, "2018 ISO New England Electric Generator Air Emissions Report," May 2020, p. 22.

[25] ISO-NE, Markets Committee, "Net CONE Supporting Data Part 1," December 3, 2017 (Revision 3 posted on February 8, 2017).

[26] Assumes 117 lbs/MMBtu as the conversion factor.

reflects the average, marginal emissions rate for the system for all-hours, on-peak, and off-peak periods.[27] These are shown in Table 4 with the associated natural gas heat rate.

Table 4. ISO-NE Marginal Emissions Rates and Implied Natural Gas Heat Rates		
	Marginal Emissions Rate (lbs/MWh)	Est. Natural Gas Heat Rate (MMBtu/MWh)
Load Weighted: All-Hours	745.0	6.4
Load Weighted: On-Peak[28]	779.0	6.7
Load Weighted: Off-Peak[29]	720.0	6.2

While these values are calculated for the entire system, the underlying hourly data are available which provide for the ability to calculate an annual, weighted average, marginal emissions rate by external interfaces (exports and imports), wholesale load, pumping load, and generation (by fuel type) where hourly generation, load, and external transaction data are available.

OPTION 3: ADJUSTED ISO-NE 2018 MARGINAL EMISSIONS RATES

Exeter identified two shortcomings with the ISO-NE approach to marginal emissions rates in the context of carbon pricing, both related to pumped-storage hydro.

1. **Pumped-storage hydro is treated as a zero emissions resource when it is pumping.**

   The ISO-NE analysis treats pumping load as having zero emissions, and while this is technically correct, there is the potential that the pumping load is being served by an emitting resource and the assignment of this interval as having a marginal emissions rate of zero is just a function of the clearing/pricing algorithm.[30] The pumped-storage hydro should be willing to bid higher in the off-peak hours (i.e., pay more to pump) based on its expectations of how the emissions rates would impact on- and off-peak prices, so the carbon price impacts their bids and thus the prices when marginal and pumping.

   To correct for this in the ISO-NE five-minute dataset, Exeter used the on-peak (779 lbs/MWh) and off-peak (720 lbs/MWh) marginal emissions rate as calculated by

[27] ISO-NE, "2018 ISO New England Electric Generator Air Emissions Report," May 2020, p. 33.

[28] *Id.,* pg. 13, "On-peak annual, consisting of all weekdays between 8:00 a.m. and 10:00 p.m."

[29] *Id.,* pg. 13, "Off-peak annual, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours."

[30] Imagine the circumstance where load is marginal in real-time in nearly every hour. This does not mean that the price that load is paying does not reflect the cost of emissions; rather, it means demand is driving the pricing (i.e., a reduction in demand is the least-cost solution). The underlying resource that is meeting the increment of demand is really what should be used in determining the marginal emissions rate.

ISO-NE as a proxy and modified the emissions rates in all five-minute intervals when the pumping load is marginal from zero to these values. This resulted in the off-peak marginal emissions rate increasing from 720 lbs/MWh to 798 lbs/MWh.

2. **Pumped storage is treated as a zero emissions resource when it is supplying.**

   With an incremental carbon price, pumped-storage hydro would be expected to increase its supply offer by the impact of the incremental cost increase associated with the carbon price when pumping (consuming).[31]

   To account for this in the ISO-NE five-minute dataset, the revised off-peak, marginal emissions rate of 798 lbs/MWh is increased by 30% (reflecting the estimated 70% efficiency of the pumped-storage hydro facilities) resulting in a marginal emissions rate of 1,037 lbs/MWh for intervals when the pumped-storage hydro is supplying power and marginal (in both on- and off-peak intervals).

Table 5 shows the impact to the adjusted marginal emissions rates and associated natural gas heat rate, building upon the results from treating the pumped-storage hydro marginal emissions rate as non-zero.

Table 5. ISO-NE Adjusted Marginal Emissions Rates and Implied Natural Gas Heat Rates

	Adjusted Marginal Emissions Rate (lbs/MWh)	Est. Natural Gas Heat Rate (MMBtu/MWh)
Load Weighted: All-Hours	916	7.8
Load Weighted: On-Peak	965	8.2
Load Weighted: Off-Peak	880	7.5

RECOMMENDATION

Exeter used Option 3 results since (1) data were available to calculate a weighted, marginal emissions rate by external interfaces (exports and imports), wholesale load, pumping load, and generation (by fuel type); (2) this approach accounted for the incorrect assessment of a zero emissions rate associated with the pumped-storage facilities; and (3) accounts for other, non-natural gas technologies being marginal.

[31] Offering storage into the market is a complicated calculation which would reflect both a minimum spread, generally reflecting the efficiency of the facility, and a forecast of future prices to ensure that the energy is bought and sold to maximize profits. The spread can be simply represented as a function of the efficiency of the facility and the cost of the power. If a pumped-storage facility paid $10/MWh to pump, it would need to be paid at least $13/MWh to break even, assuming willingness to take a zero return and 70% efficiency. If the pumping costs increases to $15/MWh because of a carbon price, the supply offer would need to be at least $19.50/MWh, thus the cost of carbon is reflected in the pumped-storage supply offers.

- The Option 1 approach did not provide hourly information to determine a generation fuel type, external interface, and load category-specific values since only one value is calculated for the period. Further, this approach does not reflect other emitting and non-emitting resources being marginal on the system, but does indirectly address the pumped-storage hydro issues.
- The Option 2 approach provides time series data to determine a weighted emissions rate by external interfaces (exports and imports), wholesale load, pumping load, and generation (by fuel type), but likely understates the cost impact because of the treatment of the pumped-storage hydro.

A comparison of the results is included in Table 6. The adjustment to the ISO-NE marginal emissions rate increased these values, but also did not adjust them beyond the emitting units-only case, which provides further support that these emissions rates are a reasonable proxy for the cost impact of an incremental carbon price

Table 6. Marginal Emissions Options Comparison

	Option 1: Average Natural Gas Emissions (lbs/MWh)	Option 2: ISO-NE Marginal Emissions All Units (lbs/MWh)	Option 3: Adjusted ISO-NE Marginal Emissions All Units (lbs/MWh)	Comparison: ISO-NE Marginal Emissions Emitting Units (lbs/MWh)
All-Hours	867	745	**916**	971
On-Peak	867	779	**965**	987
Off-Peak	867	720	**880**	960

MARGINAL EMISSIONS RATES BY GENERATION FUEL TYPE, EXTERNAL INTERFACE, AND LOAD CATEGORY

The marginal emissions data are time-weighted for the annual period and thus do not reflect how different energy profiles for load, generation, and external transactions impact their marginal emissions rates. The time-weighted approach results in the off-peak hours inherently having a greater impact on the all-hours value that is calculated by ISO-NE.

To better reflect the different hourly energy profiles for load, generation and external transactions, Exeter used hourly 2018 load,[32] generation,[33,34] and external transactions,[35] and the adjusted, hourly, marginal emissions rates to produce an annual, weighted, marginal

[32] Hourly wholesale load (excluding pumping load) was used from 2018 as available in S&P Global.

[33] ISO-NE, "2018 – Hourly Solar Generation," "2018 – Hourly Wind Generation."

[34] Hourly coal, oil, natural gas, and biomass/refuse generation were used from 2018 as available from S&P Global.

[35] ISO-NE, "2018 – External Interchange."

emissions rate that is more reflective of the price impact for each group where hourly data were available.[36]

Table 7 shows the results of this analysis by category.

Table 7. Weighted Marginal Emissions Rate by Category

Category	Hourly Weighted Marginal Emissions Rate (lbs/MWh)	Hourly Weighted Marginal Emissions Rate (short tons/MWh)
Wholesale Load[37]	931	0.4656
Coal	1,077	0.5383
Gas	939	0.4694
Oil	1,207	0.6037
Biomass/Refuse	926	0.4628
Solar[38]	921	0.4605
Wind[39]	913	0.4564
New Brunswick Import	917	0.4586
New York-North Import	935	0.4677
Hydro Quebec Phase II Import	911	0.4556
Hydro Quebec-Highgate Import	917	0.4583
New York-Shoreham Import	962	0.4811
New York-Northport Import	958	0.4790
New Brunswick Export	972	0.4858
New York-North Export	931	0.4653
New York-Shoreham Export	962	0.4811
New York-Northport Export	958	0.4790

[36] Load, import, exports, solar, coal, biomass/refuse, wind, oil, and natural gas had hourly data available. Nuclear and hydro (including pumped-storage hydro) did not have hourly data available, so had to be estimated based on the all-hours, on-peak, or off-peak marginal emissions rates.

[37] The same value was assumed for all New England states.

[38] Using the ORTP generation data for solar for 2018 resulted in a slightly higher marginal emissions rate of 933 lbs/MWh.

[39] This rate was used for both onshore and offshore wind even though this value is largely driven by onshore wind. Using the ORTP generation data for offshore and onshore wind for 2018 resulted in slightly higher marginal emissions rates of 921 lbs/MWh and 917 lbs/MWh, respectively.

Table 8 reflects the assumptions used for those categories where hourly data were not available.

Table 8. Estimated Marginal Emissions Rate by Category			
Category	Hourly Weighted Marginal Emissions Rate (lbs/MWh)	Hourly Weighted Marginal Emissions Rate (short tons/MWh)	Basis
Nuclear	916	0.4578	Option 3: All-Hours
Pumped Storage – Load	798	0.3990	As calculated above
Pumped Storage – Supply	965	0.4824	Option 3: On-Peak
Hydro (non-Pumped Storage)	916	0.4578	Option 3: All-Hours
PRD	965	0.4824	Option 3: On-Peak
Other	916	0.4578	Option 3: All-Hours

This approach resulted in the total incremental payments to suppliers and the total charges to load being about equal (0.1% difference) when adjusting for the difference between the total consumption and total supply in 2018. This outcome is consistent with what would be expected in an unconstrained system since the load is paying the same incremental price as that being paid to supply. Any differences between the load charges and supply payments are allocated to supply categories by prorating the imbalance across generation/scheduled imports for 2018 to ensure the supply payments and load charges are balanced.

Average Emissions Rates for Supply Resources

In addition to the marginal emissions rates which drive the incremental price that is paid to supply and charged to demand, an average emissions rate is required to determine the amount of a carbon tax that should be assessed for each type of emitting supply, including external transaction imports and coal, oil, natural gas, and biomass/refuse (which includes landfill gas, wood, trash burner) based generation.

Using the 2018 generation and emissions data from S&P Global (which are from EPA Clean Air Markets Division data), Exeter calculated an annual, generation-weighted average emissions rate by fuel type. These calculated average emissions values resulted in less than the total emissions (by about 2.7 million short tons) as compared to the ISO-NE published value for 2018, so Exeter adjusted each fuel type's average emissions rate up based on the generation prorated share to ensure that the total emissions in 2018 from the generation resources equaled the value that ISO-NE reported.

Table 9 provides the average emissions rates by generation fuel type and the associated adjustment for total emissions, the 2018 supply and total estimated emissions.

Table 9. ISO-NE Marginal Emissions Rates and Implied Natural Gas Heat Rates

Fuel Type	Average Emissions Rate (short tons/MWh)	Adjusted Average Emissions Rate (short tons/MWh)	2018 Supply (MWh)	2018 Emissions (short tons)
Coal	1.3335	1.4472	1,109,000	1,604,953
Natural Gas	0.4456	0.4836	50,515,000	24,428,869
Oil	0.9009	0.9777	1,161,000	1,135,133
Biomass/Refuse	1.0300	1.1178	6,228,000	6,961,834
TOTAL:			**59,013,000**	**34,130,789**

For import transactions, Exeter used the ISO-NE published average emissions rate by control area for 2018 without adjustments since the ISO-NE value was within 34,000 short tons of what was calculated in this analysis.[40] Table 10 provides the average emissions rates by importing interface, the 2018 supply and total estimated emissions.

Table 10. ISO-NE Marginal Emissions Rates and Implied Natural Gas Heat Rates

Interface	Average Emissions Rate (short tons/MWh)	2018 Supply (MWh)	2018 Emissions (short tons)
New Brunswick	0.3086	4,058,000	1,252,489
New York-Northern AC Ties	0.2238	5,394,000	1,207,010
Hydro-Quebec Phase II	0.0014	12,032,000	17,242
Hydro-Quebec Highgate	0.0014	1,934,000	2,771
New York-Cross Sound Cable	0.2238	7,000	1,566
New York-Norwalk/Northport	0.2238	189,000	42,292
TOTAL:		**23,614,000**	**2,523,370**

CARBON TAX CALCULATION

In concept, the carbon tax that is charged to suppliers should generally be equal to or less than the incremental payments; however, there are a number of reasons why in this simplified analysis this may not be the case: (1) the carbon price would have changed system commitment and dispatch, so resources would no longer be operating and thus would not be incurring a carbon tax greater than their payment or, if they were operating, they would now be the marginal resource at a higher overall energy price (this is not shown in this analysis which assumes no change in the marginal resource/dispatch); (2) resources would be getting paid

[40] ISO-NE, Environmental Advisory Group, "Estimating Environmental Attributes of System Imports to New England," p. 5.

uplift to cover the costs of the carbon tax (these costs would be reflected in their offers into the electricity market and be paid when revenues did not cover their costs), but not paid through the incremental payment methodology in this analysis; or (3) resources with higher emissions rates that were inframarginal would be earning less inframarginal revenues (i.e., this analysis would show this as an incremental charge) because a lower-emitting, but still more expensive, resource is setting the price.[41] Further, since the value used for the average emissions rate is estimated using a non-ISO-NE data source and is further adjusted to match the total emissions for the region in 2018, this adds further noise to the average emissions rates.

Since this analysis applied a simplified approach and is performed on an annual basis, there is no easy way to differentiate between these three cases, the frequency of these events, or define a more refined emissions rate by technology, so Exeter focused on the net outcome in its results, rather than providing a breakdown by supply resource type. This net charge to emitting suppliers was 10.6% in each scenario, so could be interpreted as a further increase in costs, even though Exeter did not include this impact in its results for the reasons noted above.

Emissions Rate Changes Over Time

Exeter assumed that fixed marginal and average emissions rates over the life of each project aligned with the 2018 data that was used as the basis for determining these values. Using constant values over the period is a reasonable approximation because the average energy price that needs to be paid to a project to meet the annual revenue requirement is not impacted by the marginal emissions rate or the carbon price, as the model solves for this incremental energy price first and then determines the carbon price by the marginal emissions rate associated with the project.

- If the marginal emissions rate for the project declines, the carbon price would need to increase to maintain the same level of electricity market revenues to meet the project's annual revenue requirement; however, the cost to load and payments to suppliers should not change significantly assuming the marginal emissions rates are fairly consistent across the different categories. In concept, if marginal emissions rates are declining, then the average technology emissions rates (which form the basis for assessing the carbon tax) should also be reduced, so a higher carbon price should produce a similar netting impact.
- If the system marginal emissions rate increases (which seems unlikely with more efficient emitting technologies entering the power system, even if load is increasing), the carbon price would need to decrease to maintain the same level of energy revenues to meet the annual revenue requirement for the projects; however, similar to the above, the cost to load and payments to suppliers should not change significantly since

[41] This would be applicable to coal and oil resources under circumstances where natural gas is on the margin.

the incremental energy price required is driving the carbon price. In concept, if marginal emissions rates are increasing, then the average technology emissions rates (which form the basis for assessing the carbon tax) should also be increasing, so a lower carbon price should produce a similar netting impact.

MODELED CALCULATIONS

Incremental Carbon Price

For each identified project scenario (utility-scale solar, onshore wind, and offshore wind, plus additional cases for increased transmission costs), the calculation for additional revenue required from the energy market ($/year) to allow a technology to be economically developed assuming a specific amount of forward capacity market revenue each year over the life of the project can be represented as:

$$\text{Annualized Qualified Capacity}_{\text{Project}} = ((4 \text{ months} \times \text{Summer Qualified Capacity}_{\text{Project}}) + (8 \text{ months} \times \text{Winter Qualified Capacity}_{\text{Project}})) / 12 \text{ months}$$

$$\text{Adjusted Net Levelized Costs Qualified}_{\text{Project}} = \text{Net Levelized Costs Installed}_{\text{Project}} \times \text{Annualized Qualified Capacity}_{\text{Project}} / \text{Max Capacity}_{\text{Project}}$$

$$\text{Energy Market Required Revenue}_{\text{Project}} = (\text{Adjusted Net Levelized Costs Qualified}_{\text{Project}} - \text{Average Expected Capacity Price}) \times 1000 \text{ kW/MW} \times 12 \text{ months} \times \text{Annualized Qualified Capacity}_{\text{Project}}$$

Where:

- *Annualized Qualified Capacity* $_{Project}$ references the specific renewable project scenario for which the analysis was performed.
- *Summer Qualified Capacity* $_{Project}$ is the qualified capacity based on the ISO-NE ORTP dispatch model,[42] measuring performance in hour ending (HE) 18 and 19 during the summer months (June through September) and calculating the average of each year's seasonal summer median value for 2017, 2018, and 2019.
- *Winter Qualified Capacity* $_{Project}$ is the qualified capacity using the ISO-NE ORTP dispatch model,[43] measuring performance in HE 14 to 18 during the winter months (October through May) and calculating the average of each year's winter summer median value for 2017, 2018, and 2019.
- *Net Levelized Costs Installed* $_{Project}$ is the ORTP in $/kW-mo calculated by ISO-NE and presented at the August 2020 Markets Committee meeting and adjusted for

[42] ISO-NE, Markets Committee, August 11-13, 2020, "Concentric Energy Advisors ORTP Models."

[43] *Ibid.*

transmission costs provided by NESCOE of an incremental $20 million (2019$) for offshore wind and an incremental $133 million (2019$) for onshore wind.[44,45]

- *Max Capacity Project* is the nameplate capability of the resource as provided for in the ORTP assumptions.[46]
- *Average Expected Capacity Price* is the level of expected capacity revenues over the life of the project. This is set at $2.00/kW-mo for the base case analysis reflecting the most recent forward capacity auction results. Exeter ran a sensitivity analysis at $4/kW-mo (average of last five auctions' prices).

The calculation for the average, hourly energy price increase ($/MWh) required to provide adequate compensation for each identified project scenario to allow for the resource to clear and earn a fixed amount of capacity revenue can be represented as:

$$\text{Annual Energy Production}_{\text{Intermittent Project}} = \text{Energy-based Capacity Factor}_{\text{Project}} \times \text{Max Capability}_{\text{Project}} \times \text{Performance Days}$$

$$\text{Annual Energy Production}_{\text{Storage Technology}} = \text{Round-Trip Efficiency}_{\text{Project}} \times \text{Energy Storage}_{\text{Project}} \times \text{Performance Days}$$

$$\text{Incremental Energy Price}_{\text{Project}} = \text{Energy Market Required Revenue}_{\text{Project}} / \text{Annual Energy Production}_{\text{Project}}$$

Where:

- *Performance Days* is the number of days the resource is expected to perform during the period. For intermittent resources, this is assumed to be 365 days since the capacity factor already takes into account some level of non-performance. For storage resources, this is assumed to be 350 days, which assumes a daily cycle approach to operation that is limited based on contractual arrangements with the manufacturer/supplier.
- *Energy-based Capacity Factor Project* is the average capacity factor from the ORTP models.[47]

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[44] ISO-NE, Markets Committee, August 11-13, 2020, "Discounted Cash Flow Model."

[45] The "ORTP Qualified" calculated by ISO-NE is not used in this analysis because ISO-NE's approach uses an "all-hours" capacity factor as opposed to applying the intermittent qualification rules which only measure specific peak hour performance. The qualified values are slightly lower than the values that will become the basis for which these projects are paid.

[46] ISO-NE, Markets Committee, August 11-13, 2020, "Discounted Cash Flow Model."

[47] *Ibid.*

- *Round-Trip Efficiency* $_{Project}$ is the value used in the ORTP models for storage.[48]

The incremental (to RGGI and Massachusetts emissions limits) carbon tax ($/short ton) required to provide adequate compensation for each identified technology scenario to have adequate revenue to be developed can be calculated as:

$$\textit{Incremental Carbon Price}_{\textit{Intermittent Project}}\ (\$/\textit{short ton}) = \textit{Incremental Energy Price}_{\textit{Project}} \,/\, \textit{Annualized Marginal } CO_2 \textit{ Emission Rate}_{\textit{Project}}$$

$$\textit{Incremental Carbon Price}_{\textit{Storage Project}}\ (\$/\textit{short ton}) = \textit{Incremental Energy Price}_{\textit{Project}} \,/\, (\textit{Annualized Marginal } CO_2 \textit{ Emission Rate}_{\text{Storage Supply}} - \textit{Annualized Marginal } CO_2 \textit{ Emission Rate}_{\text{Storage Consumption}})$$

Where:

- *Annualized Marginal* CO_2 *Emission Rate* $_{Project}$ is set per the discussion in the section above on Marginal Carbon Emissions Rates in MWh/short ton.

Energy Market Supplier and Load Impact

The calculation for the incremental energy market payment ($) by resource type (gas, oil, biomass/refuse, coal, nuclear, hydro, pumped-storage hydro, imports, wind, solar, and demand response) and category (supply and imports) can be represented as:

$$\textit{Effective Carbon Adder}_{\textit{Resource Type}}\ (\$/\textit{MWh}) = \textit{Incremental Carbon Price}_{\textit{Project}} \times \textit{Annualized Marginal CO2 Emission Rate}_{\textit{Resource Type}}$$

$$\textit{Incremental Energy Market Payment}_{\textit{Resource Type}} = \textit{Supply}_{\textit{Resource Type}} \times \textit{Effective Carbon Adder}_{\textit{Resource Type}}$$

$$\textit{Incremental Energy Market Payment}_{\textit{Category}} = \textit{SUM}\ [\ \textit{Incremental Energy Market Payment}_{\textit{Resource Type}}\ ]$$

$$\textit{Effective Load Carbon Adder}_{\textit{Category}} = \textit{AVERAGE}\ [\textit{Effective Carbon Adder}_{\textit{Resource Type}}],\ \textit{supply weighted}$$

$$\textit{Incremental Energy Market Payment}_{\textit{Supply}} = \textit{SUM}\ [\ \textit{Incremental Energy Market Payment}_{\textit{Category}}\ ]$$

$$\textit{Effective Load Carbon Adder}_{\textit{Supply}} = \textit{AVERAGE}\ [\textit{Effective Carbon Adder}_{\textit{Resource Type}}],\ \textit{supply weighted}$$

Where:

- *Supply* $_{Resource\ Type}$ is the *Generation* $_{Fuel\ Type}$, *Scheduled Imports* $_{Interface}$, and *Demand*

[48] *Ibid.*

$Reduction_{\text{Demand Response}}$ in MWh from 2018.[49]

The calculation for the total energy market cost ($) by category (wholesale load, exports, and pumped-storage hydro) and subcategory (state, exporting interface and pumped-storage hydro) and can be represented as:

$$\text{Effective Carbon Adder}_{\text{Sub-category}} = \text{Incremental Carbon Price}_{\text{Project}} \times \text{Annualized Marginal CO2 Emission Rate}_{\text{Sub-category}}$$

$$\text{Incremental Energy Market Cost}_{\text{Sub- category}} = \text{Load}_{\text{Sub-category}} \times \text{Effective Carbon Adder}_{\text{Sub-category}}$$

$$\text{Incremental Energy Market Cost}_{\text{Category}} = \text{SUM [Incremental Energy Market Cost}_{\text{Sub- category}}\text{]}$$

$$\text{Effective Load Carbon Adder}_{\text{Category}} = \text{AVERAGE [Effective Carbon Adder}_{\text{Sub-category}}\text{], load weighted}$$

$$\text{Incremental Energy Market Cost}_{\text{Load}} = \text{SUM [Incremental Energy Market Cost}_{\text{Category}}\text{]}$$

$$\text{Effective Load Carbon Adder}_{\text{Load}} = \text{AVERAGE [Effective Carbon Adder}_{\text{Sub-category}}\text{], load weighted}$$

Where:

- $Load_{\text{Sub-category}}$ is the annual $Wholesale\ Load_{\text{State}}$,[50] $Scheduled\ Exports_{\text{Interface}}$,[51] and $Pumping\ Load_{\text{Pumped-Storage Hydro}}$[52] in MWh from 2018.

An adjusted energy market payment is required to address the imbalance between incremental payments and charges. The adjustment and final incremental energy payment can be represented as:

$$\text{Total Supply}_{\text{Annual}} = \text{SUM [Supply}_{\text{Resource Type}}\text{]}$$

$$\text{Total Load}_{\text{Annual}} = \text{SUM [Load}_{\text{Category}}\text{]}$$

$$\text{Supply/Demand Difference}_{\text{Annual}} = \text{Total Load}_{\text{Annual}} - \text{Total Supply}_{\text{Annual}}$$

$$\text{Supply/Demand Settlement Difference}_{\text{Annual}} = \text{Effective Load Carbon Adder} \times \text{Supply/Demand Difference}_{\text{Annual}}$$

[49] ISO-NE, "Net Energy and Peak Load by Source.xlsx File," 2018.

[50] ISO-NE, "Annual Generation and Load Data for ISO NE and the Six New England States," June 7, 2019.

[51] ISO-NE, "Net Energy and Peak Load by Source.xlsx File" 2018.

[52] *Ibid.*

$$Imbalance\ to\ Allocate = Incremental\ Energy\ Market\ Cost_{\ Annual} - Incremental\ Energy\ Market\ Payment_{\ Annual} - Supply/Demand\ Settlement\ Difference_{\ Annual}$$

$$Adjustment\ to\ Incremental\ Energy\ Payment_{\ Resource\ Type} = Imbalance\ to\ Allocate \times (Supply_{\ Resource\ Type} / Total\ Supply_{\ Annual})$$

$$Final\ Incremental\ Energy\ Payment_{\ Resource\ Type} = Adjustment\ to\ Incremental\ Energy\ Payment_{\ Resource\ Type} + Incremental\ Energy\ Market\ Payment_{\ Resource\ Type}$$

Carbon Tax and Carbon Tax Distribution Fund

The CO_2 emissions (short tons) for emitting supply including generation and import resources can be calculated as:

$$CO_2\ Emissions_{\ Resource\ Type} = Average\ Emissions\ Rate_{\ Fuel\ Type} \times Supply_{\ Fuel\ Type}$$

Where:

- *Supply* $_{Fuel\ Type}$ is the *Generation* $_{Fuel\ Type}$ and *Scheduled Imports* $_{Interface}$ in MWh from 2018.[53] *Demand Reduction* $_{Demand\ Response}$ is assumed to be from non-emitting technologies.
- *Average Emissions Rate* $_{Fuel\ Type}$ is calculated using a combination of the following data: (1) U.S. Energy Information Administration (EIA) data for 2018 (includes total emissions by plant);[54] (2) S&P Global data for 2018 (including emissions rates and implied heat rates); (3) heat rate data from the 2017 Net CONE/ORTP review;[55] and (4) the ISO-NE 2018 emissions report;[56] and was further adjusted to match total emissions as discussed above in the section on Average Emissions Rates for Supply Resources.
- *Scheduled Imports* $_{Interface}$ is the scheduled imports by interface for 2018 in MWh.[57]

The calculation of the Carbon Tax ($) for each generation fuel type and importing interface and by category (generation and imports) can be represented as:[58]

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[53] *Ibid.*

[54] EIA, "Emissions by plant for CO2, SO2, and NOx - 2018," CO2.

[55] ISO-NE, Markets Committee, "Supporting Data for the Cost of New Entry and Offer Review Trigger Prices - Part 1," Generators.

[56] ISO-NE, "2018 ISO New England Electric Generator Air Emissions Report," May 2018.

[57] ISO-NE, "Net Energy and Peak Load by Source.xlsx File" 2018.

[58] Fuel types not identified with an emissions rate are considered to be non-emitting and do not have an associated carbon tax.

$$\text{Incremental Carbon Tax}_{\text{Resource Type}} = CO_2 \text{ Emissions}_{\text{Resource Type}} \times \text{Incremental Carbon Tax Rate}_{\text{Project}}$$

$$\text{Incremental Carbon Tax}_{\text{Category}} = \text{SUM [applicable Incremental Carbon Tax}_{\text{Resource Type}}\text{]}$$

$$\text{Incremental Carbon Tax}_{\text{Supply}} = \text{SUM [Incremental Carbon Tax}_{\text{Category}}\text{]}$$

The calculation of the Carbon Tax Disbursement Fund ($) can be represented as:

$$\text{Carbon Tax Disbursement Fund} = \text{Incremental Carbon Tax}_{\text{Supply}}$$

Net CONE Impact

Note: A significant downward revision to Net CONE could shift the expectation of the amount of capacity revenues that would be available. Exeter did not analyze the impact to the capacity market outcomes of increased revenues to the Net CONE resource.

The calculation of a revised Net CONE value ($/kW-mo) associated with the combined cycle and simple cycle proxy resources used in the Net CONE can be represented as:

$$\text{Effective Carbon Adder}_{\text{Proxy Resource}} (\$/\text{MWh}) = \text{Incremental Carbon Price}_{\text{Project}} \times \text{Annualized Marginal CO2 Emission Rate}_{\text{Proxy Resource}}$$

$$\text{Incremental Energy Market Payment}_{\text{Proxy Resource}} (\$/\text{MWh}) = \text{Generation}_{\text{Proxy Resource}} \times \text{Effective Carbon Adder}_{\text{Proxy Resource}}$$

$$\text{Incremental Energy Market Payment}_{\text{Proxy Resource}} (\$/\text{kW-mo}) = \text{Incremental Energy Market Payment}_{\text{Proxy Resource}} (\$/\text{MWh}) / 12 \text{ months} / 1000 \text{ kW/MW}$$

$$CO_2 \text{ Emissions}_{\text{Proxy Resource}} = \text{Average Emissions Rate}_{\text{Proxy Resource}} \times \text{Generation}_{\text{Proxy Resource}}$$

$$\text{Carbon Tax}_{\text{Proxy Resource}} (\$) = CO_2 \text{ Emissions}_{\text{Proxy Resource}} \times \text{Incremental Carbon Tax Rate}_{\text{Technology}}$$

$$\text{Carbon Tax}_{\text{Proxy Resource}} (\$/\text{kW-mo}) = \text{Carbon Tax}_{\text{Proxy Resource}} (\$) / \text{Qualified Capacity}_{\text{Proxy Resource}} / 12 \text{ months} / 1{,}000 \text{ kW/MW}$$

$$\text{Adjusted Net CONE}_{\text{Proxy Resource}} = \text{Net CONE}_{\text{Proxy Resource}} - \text{Incremental Energy Market Payment}_{\text{Proxy Resource}} (\$/\text{kW-mo}) + \text{Carbon Tax}_{\text{Proxy Resource}} (\$/\text{kW-mo})$$

Where:

- *Generation* $_{\text{Proxy Resource}}$ is the estimated annual energy production for each proxy resource.[59]

[59] ISO-NE, Markets Committee, August 11-13, 2020, "Net CONE Dispatch Models."

- *Average Emissions Rate* $_{\textit{Proxy Resource}}$ is calculated as an annual, weighted generation emissions rate using the heat rates and dispatch for 2018 from the ORTP models.[60]
- *Net CONE* $_{\textit{Proxy Resource}}$ is the Net CONE value calculated by ISO-NE for each proxy resource.[61]

[60] *Ibid.*

[61] ISO-NE, Markets Committee, August 11-13, 2020, "Discounted Cashflow Model."