Anne C. George
Vice President
External Affairs and Corporate Communications

February 20, 2017

Mr. Martin Suuberg
Commissioner
Massachusetts Department of Environmental Protection
One Winter Street
Boston, Massachusetts 02108

Dear Commissioner Suuberg:

ISO New England, Inc. (ISO) appreciates the opportunity to comment on the Massachusetts Department of Environmental Protection's (MA DEP) proposed regulations to implement Section 3(d) of the Global Warming Solutions Act (GWSA). The MA DEP has proposed a comprehensive set of regulations that together seek to address the mandates from the GWSA, the Massachusetts Supreme Judicial Court's decision in *Kain v. Department of Environmental Protection*, and Governor Baker's Executive Order 569. The ISO acknowledges that no single element of the proposed regulations is intended to address all of the mandates; however, the ISO is limiting its comments to the proposed regulation (310 CMR 7.74: *Reducing Greenhouse Gas Emissions From Electricity Generating Facilities* (EGU limit regulation)).

The ISO recognizes the efforts of Massachusetts to reduce greenhouse gas (GHG) emissions, and provides these comments to assist the commonwealth in achieving those reductions in a reliable, efficient and cost-effective manner for the state and ultimately the region.

The ISO has reviewed the proposed regulation that caps emissions at electric generation plants in Massachusetts, and given the limited time for analysis, was able to conduct a high-level assessment of the rules' impact on regional generation, emissions and wholesale electricity costs.

The results of our analysis indicate that under the proposed regulation, the region can maintain reliable electricity service by shifting electricity production from power plants in Massachusetts to other states. This shift in electricity production, however, can increase regional emissions and raise wholesale electricity costs. Generally speaking, the ISO's analysis shows a modest increase in regional emissions, because electricity production is shifted from Massachusetts to less efficient plants and likely higher emitting fuel sources in the region.

The regional cost of electricity also increases under the ISO's analysis. While the ISO's analysis suggests modest emissions and cost increases (ranging from $0.00 - $0.35/MWh), it appears that the state will have difficulty meeting its desired carbon emission reductions from the electricity sector if it relies solely on the regulation because these limits, if they are binding, actually increase the emissions associated with Massachusetts electricity consumption. The more stringent the emissions limits, the greater the effect.

Assuming these regulations move forward, the ISO has three specific recommendations that can further improve the efficiency of the rules and mitigate cost and regional emissions increases and help ensure reliable electric service for the commonwealth and the region.

First, the **ISO suggests the state utilize an auction to allocate carbon emission credits** to electricity suppliers rather than employing an administrative process that awards initial emission credits based on historical use, projected future emissions, or some other criteria. An auction will allow market participants to reflect their private valuation for emissions credits while accounting for expected production, potential capital investments that could reduce emissions, future market conditions, and their risk tolerance. The auction would sell these credits to the set of market participants who value them most. This is an efficient outcome as it awards the credits to the resources that maximize the value of the credits, and allows the state to cost effectively meet its environmental objective.

This efficient allocation does not occur under an administrative process where the credits are not allocated to the resources that value them most, and instead uses an alternate framework such as historical emissions, which may not be indicative of emissions going forward. To the extent that the trading of permits between resources is limited (either because of poor information about their market value or market power that limits the set of counterparties), the most cost effective set of resources would not be able to deliver energy, which would increase total costs and emissions relative to an efficient distribution of permits.

Additionally, because an auction sends a transparent price signal to all participants about the value of an emissions credit, it may increase the emission credit market's liquidity by helping to facilitate the trading of credits after the auction, which will inevitably be necessary as plant and market conditions evolve. This increased liquidity will help ensure that the state meets its environmental objective in a cost effective manner, and will reduce a resource's risk of incurring financial penalties because it cannot procure sufficient credits to offset its carbon emissions.

Second, the **ISO suggests that the proposed regulation should not supersede current air permit limits for generators with new administrative caps**. Such a move would render plants unable to run even if credits were available to them through an auction or post-auction secondary market. The transfer of credits between facilities is already contemplated by the draft regulations in 310 CMR 7.74(6)(c), albeit on the limited basis of the transfer of over compliance credits to other facilities. But even on that limited basis, a new cap in an air permit would limit a plant to the pre-credit transfer emissions. The draft proposal to cap air permits at the administrative cap is problematic in that it could curtail newer, cleaner and more efficient resources from operating and result in older and less efficient resources operating in their place.

Third, **the regulation should include a mechanism to mitigate any negative impact to electric reliability.** This could be structured as a reliability safety valve wherein a resource could operate past its credit allotment for reliability-related reasons[1] with a 1-for-1 repayment rather than a 3-for-1 repayment. Alternately, if emissions credits are auctioned there could be a provision to "buy through" into next year's quantity at a multiple of the current year's auction value. This value could be high enough to prevent casual use of the provision, but would provide valuable certainty to both plant owners and the ISO.

Background

Created in 1997, the ISO is the independent, not-for-profit corporation responsible for the day-to-day reliable operation of New England's bulk power generation and transmission system; development and operation of the region's wholesale electricity markets; and management of a comprehensive regional bulk power system planning process. The ISO serves the New England region which includes Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. The ISO is regulated by the Federal Energy Regulatory Commission (FERC).

Since their start in 1999, New England's competitive wholesale electricity markets have resulted in significant efficiencies and stimulated billions of dollars of private investment in approximately 16,000 MW of new generation. The region's transition to competitive markets has shielded ratepayers from bad investment decisions and has spurred the development of a more efficient and flexible fleet of resources, which are now able to deliver power to customers from the most efficient resources around the region thanks to investments in transmission infrastructure.

The competitive wholesale electricity markets, coupled with an abundance of relatively cheap natural gas nearby, as well as environmental regulations and policies have driven changes in New England's resource mix and utilization. Since 2000, the New England power system has undergone a major transformation – the region has shifted to natural gas-fired generation. Almost half (49%) of the electricity produced in New England in 2016 was derived from natural gas – up from 15% in 2000. Over the same period, electricity produced from coal and oil combined dropped from 40% to about 3%. This transformation has brought benefits and challenges to the region.

The region's shift in fuel from coal and oil to less-emitting sources, primarily natural gas, has resulted in significant reductions in emissions from the region's electricity generating fleet. From 2001 to 2014, annual emissions for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and carbon dioxide (CO_2) declined by 66%, 94%, and 26%, respectively. However, over the past several winters, when natural gas supply to electric generation is limited or more expensive, the New England states have relied on oil and coal to produce the electricity the region needs.

The region's wholesale electricity markets and the enabling investment in the transmission to allow for competition between resources have served the region well over the past two decades, resulting

[1] For example, reliability-related reasons could include an order to operate by the United States Secretary of Energy under Section 202 (c) of the Federal Power Act. (See 16 U.S.C. § 824 a (c) (2016)).

in the efficient use of resources and attracting investment in cleaner, more efficient generation and demand resources in the region.

While the shift in the resource mix has brought benefits to the region, it has also brought challenges. The upcoming retirement of non-gas-fired generators (including Brayton Point and Pilgrim Nuclear which account for 2,100 MW of capacity) exacerbates New England's dependence on a constrained natural gas system and represents a challenge for us as the regional system operator. These operational challenges are not likely ending anytime soon, as half of the proposed power plants in the region are gas-fired. Furthermore, these challenges are made even more acute if these proposed rules limit production, or hasten the retirements, of non-gas generation.

Proposed Regulation

The proposed EGU limit regulation establishes an aggregated state limit with respect to GHG emissions as well as a declining limit on GHG emissions from both new and existing power plants in the state. The cap for each plant, as well as the aggregate limit, will decline at a rate of 2.5% each year from 2018 to 2050. New facilities receive a set portion of the aggregate limit, which stays constant until 2025 before declining at the same rate as the existing plants. The regulations allow for over-compliance credits to be created in an annual compliance period, which can be transferred among power plants in the state or retained for future use.

ISO Analysis

The ISO conducted a modeling study in an attempt to identify the potential impact of the proposed EGU limit regulation. While no model captures all of the variables that can occur in the regional power system, the model simulates various scenarios in which to evaluate the impact of the regulation.[2]

The ISO's analysis simulated the year 2025 for two resource scenarios and then considered sensitivities that included additional hydro imports and offshore wind.[3] The ISO believes that, while it is impossible to know exactly what future years will look like, the qualitative results are informative and robust across a range of possible futures.

The ISO's analysis shows that the design of the proposed EGU limit regulation has consequences to Massachusetts and the other New England states due to the regional nature of the electric power system. Under this proposed regulation, Massachusetts seeks to meet emissions goals by limiting in-state generation which in turn shifts generation to resources in other states to make up the energy shortfall. Our modeling results show that when this occurs, relatively efficient clean burning

[2] It should be noted that the model does not include potential constraints on the natural gas pipeline system. As ISO New England has discussed in several reports, fuel security is a critical challenge for the region.

[3] The ISO's analysis utilized existing base cases, scenarios and assumptions from the region's 2016 Economic Study.

facilities in Massachusetts are operated less, and relatively inefficient and less clean resources in other states are run more. When the additional emissions associated with the incremental non-Massachusetts generation are added back to Massachusetts, emissions totals attributable to Massachusetts under the regulation actually increase under the proposed policy. Total New England emissions increase by the same amount attributable to the policy.

The degree to which emissions and costs increase under the policy is directly related to the cap. The results range from no effect if the cap is not binding (*i.e.* does not limit generator output) to increases in generator offers, consumer costs, and emissions if the cap requires shifts in generation. While the ISO is only presenting results from a small possible shift in emissions in 2025, we did evaluate the effect of greater shifts under the cap that might be applicable if loads are higher than modeled, or that might occur in later years as the caps become increasingly tight. In each case, as the caps get more restrictive, costs and emissions increase. These model results also assume a perfectly efficient distribution of credits – to the extent that credits are not distributed efficiently – costs and emissions will be higher.

Our analysis indicates that the proposed rules in the best case, with a non-binding cap, would show no effect. If the emissions limits are binding they should be expected to raise consumer costs and *increase* carbon emissions associated with Massachusetts. The less efficient the final allocation of credits is, the greater the costs and emissions.

Similarly, in most of the scenarios we conducted in our analysis[4] (absent additional imports and off-shore wind), we saw locational marginal price increases between \$0.00/MWh and \$0.35/MWh.

Recommendations
The ISO believes our suggestions below will reduce as much as possible the cost and regional emissions impacts discussed above.

Credits Should be Allocated by Auction Rather than a Plant-by-Plant Assignment
The ISO suggests the state utilize an auction to allocate carbon emission credits to electricity suppliers rather than employing an administrative process that awards initial emission credits based on historical use, projected future emissions, or some other criterion.

An auction will allow market participants to reflect their private valuation for emissions credits while accounting for expected production, potential capital investments that could reduce emissions, future market conditions, and their risk tolerance. The auction would sell these credits to the market participants who value credits the most, which is an efficient outcome that allows the state to cost effectively meet its environmental objective.

[4] A detailed summary of the ISO's emissions and cost analysis is included in the materials immediately following these comments.

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This efficient allocation does not occur under an administrative process which instead uses an alternate framework such as historical emissions, which may not be instructive of emissions going forward. To the extent that the trading of permits between resources is not permitted or is limited, such a design would prevent the most cost effective set of resources from delivering energy while also meeting the state's environmental objectives, thereby increasing total costs and emissions relative to an auction design.

Additionally, because an auction sends a transparent price signal to all participants about the value of an emission credit, it will help to facilitate the efficient trading of credits after the auction that will inevitably be necessary as plant and market conditions evolve. This increased liquidity relative to an administrative allocation will help ensure that the state meets its environmental objective in a cost effective manner, and will reduce a plant's risk of incurring financial penalties because it cannot procure sufficient credits to offset its carbon emissions. In the process, an auction-based allocation would value the carbon credits and create revenue that could be invested in energy policies that further the state's greenhouse gas goals.

Furthermore, because a ton of carbon emissions has an equivalent impact whether from a new or existing generation resource, the regulations should not separate existing and new resources into different categories. Rather, all resources should be allowed to value and procure carbon emission credits based on the performance characteristics of a generating facility. This should have the effect of more credits being procured by the set of resources that values them most, which would allow Massachusetts to meet its environmental objectives in a cost effective manner.

In order to help generators better manage their procured credits over the course of an operating year, the ISO suggests that the carbon auction's emission year should be consistent and aligned with the region's electric power year which runs from June 1 to May 31. This timing is consistent with the timing of the region's annual Forward Capacity Market. This will have the added reliability benefit of moving the end of the emission year from December, a time when the electric system is particularly challenged due to fuel limitations on the existing natural gas system. Stated another way, moving the timing will allow generators to better manage their allocations and ensure that these resources are available when the system experiences peak electricity demands.

Current Generator Plant Air Permits Should Not be Superseded by New Plant Limits
Proposed 310 CMR 7.74 (12) specifies that the individual GHG emission limits provided in 310 CMR 7.74 (5) replace the declining annual CO_2 emissions limits in an individual facility's plan approval issued pursuant to 310 CMR 7.02. We recommend that this provision should be removed as it is incompatible with the more efficient auction and secondary trading market design discussed above.

Newer resources with declining annual CO_2 emissions limits (issued pursuant to 310 CMR 7.02) offer the commonwealth the opportunity to leverage less carbon intensive generation from amongst the most efficient, least emitting and most economic resources. By replacing 310 CMR 7.02 declining annual CO_2 emissions limits with the 310 CMR 7.74(5) individual GHG emission limits, the generator

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emissions cap will likely require higher emitting and more expensive resources around the region to operate to make up the shortfall.

The Regulations Should Include a Mechanism to Mitigate Potential Reliability Concerns
Power systems can experience unexpected events that require the operation of power plants to ensure power system reliability. A key to that is the dispatch of generation in a given area to create the necessary real and reactive energy to serve load and unload stressed power lines.

While the draft regulation contains a 3-for-1 repayment for operating over a given limit, the ISO suggests that the repayment methodology should be modified to also provide a reliability safety valve under which generators that have exhausted their procured credits and are dispatched for system reliability needs would repay over-emission on a 1-for-1 basis. Generators that over-emit under these circumstances could then offset that over emission in the next operating year or through procuring additional credits in the secondary market if they are available.

Alternately, an auction could be designed to include a predetermined financial penalty for any carbon emitted in excess of a resource's credits or allow a resource to buy-through to the following year. A known financial penalty would provide resources with certainty and allow them to incorporate the potential penalty into their electricity market offers.

Conclusion
Thank you for this opportunity to provide comments. Given our unique role as operator of the regional power system, ISO New England believes the recommendations outlined above will improve the efficiency of the proposed rule and mitigate the reliability, environmental and cost impacts of the proposed EGU limit regulation.

Sincerely,

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Evaluation of Proposed MA DEP Regulations Capping CO_2 Emissions in the Electricity Sector

Summary of ISO Analysis of Proposed DEP Regulations

- Analysis has been performed to quantify the emissions impact of the proposed MA DEP regulations relating to emission caps
  - Quantify impact on emissions from generators physically located
    - Within Massachusetts
    - Outside of Massachusetts
- Imports
  - This analysis includes the effect of emissions associated with imports into Massachusetts
  - Imports refer to the energy generated from resources located outside of Massachusetts used to serve load in Massachusetts

OBSERVATIONS

Observations

- ISO used a production cost model and publicly vetted inputs to evaluate proposed MA DEP regulations, initially looking for reliability concerns associated with limited generation.
- Model shows that a Massachusetts CO_2 cap increases CO_2 emissions
  - Total MA CO_2 emissions increase when incremental imports to MA are assigned incremental emissions associated with policy
  - The effect would be masked if average emission rates were used
- The CO_2 increase occurs because dispatch process shifts some energy from relatively low emitting MA generators to higher emitting non-MA generators
- Procurement of additional non-emitting resources such as hydro imports and offshore wind decrease New England total emissions and total MA allocated emissions

Observations (*continued*)

- The net impact of the proposed DEP regulations is to increase the total New England emissions (and the Massachusetts allocated emissions) by 34 – 136 k-tons per year*
  - An increase in New England emissions under a Massachusetts cap is a consistent result across future scenarios
- A relatively low decremental emission rate for Massachusetts resources
  - Based on many relatively low emitting resources within Massachusetts
  - High CO_2 emitting coal resources already retired
- A relatively high incremental emission rate for non-Massachusetts resources
  - Based on many relatively low emitting resources outside Massachusetts
  - Some higher CO_2 emitting resources remain in service
  - Higher than the decremental emission rate for Massachusetts resources

* Assuming a $2/ton-$CO_2$ premium for CO_2 allowances required by Massachusetts affected units

METHODOLOGY

Methodology

- Review the impact of a Massachusetts specific emissions cap in the context of a region-wide RGGI price-driven allowance framework (RGGI price of $19 in 2025)
- Conduct a parametric analysis using the ABB GridView production-cost simulation model and simulate the year 2025 for two resource scenarios (developed for 2016 Economic Studies (2016 ES))
  - Reference Case - assumes no retirements of coal and oil resources beyond those accepted in FCA 10 (Scenario 4 of 2016 ES)
  - Retirement Case - assumes that half of the conventional coal-steam and residual oil-steam generators, 2,610 MW out of 5,577 MW will be retired and replaced with natural gas combined cycle resources built at the same site of the retired resources (Scenario 5 of 2016 ES)

Methodology (*continued*)

- For each case, consider two sensitivities affecting New England emissions
  – Additional 1,200 MW of hydro imports from Quebec into New England
  – Additional 1,200 MW of hydro imports from Quebec into New England plus 1,600 MW of offshore wind
- Re-run each simulation with carbon cap in place:
  – $19/ton* RGGI allowance price adder for all RGGI units
  – Additional $2/ton-$CO_2$ adder for all resources subject to MA carbon cap
- Evaluate the effect of these sensitivities on:
  – Total emissions in New England
  – Massachusetts share of emissions
    - Emissions from resources physically located in Massachusetts, plus
    - Emissions associated with imports

* Ton refers to short ton through out this presentation

Retirement Case

Fossil Retirements by 2025 in Scenario 5 of 2016 ES

Name	RSP Subarea	FCA#10 Summer Qualified Capacity (MW)	Resource Type	Cumulative Capacity (MW)
Schiller 4	NH	47.5	Coal	47.5
Montville 5	CT	81	Oil	128.5
Schiller 6	NH	47.9	Coal	176.4
West Springfield 3	WMA	94.3	Dual	270.7
Yarmouth 1	SME	50.3	Oil	321
Middletown 2	CT	117	Oil	438
Yarmouth 2	SME	51.1	Oil	489.1
Merrimack 1	NH	108	Coal	597.1
Middletown 3	CT	233.7	Oil	830.8
Yarmouth 3	SME	114.5	Oil	945.3
Bridgeport Harbor 3	SWCT	383.4	Coal	1328.7
Canal 1	SEMA	547.1	Oil	1875.8
Merrimack 2	NH	330	Coal	2205.8
Montville 6	CT	405	Oil	2610.8

ACCOUNTING FOR EMISSIONS FROM IMPORTS

Accounting for Emissions from Imports

- The results indicated that the use of higher carbon allowance prices on Massachusetts generators would:
  - Decrease the competitiveness of generators physically located within the physical boundaries of Massachusetts subject to MAGWSA
  - Decrease the generation of energy by these resources
  - Increase the generation of energy by units located outside of Massachusetts
  - Increase the amount of energy that is imported back into Massachusetts to serve customer loads within the state
  - Emissions from resources located outside of Massachusetts would increase
  - Emissions from resources located inside of Massachusetts would decrease
- The state is required to account for the changes in emissions resulting from implementation of the proposed regulations
  - Assume that all incremental emissions outside Massachusetts will be assigned back to Massachusetts
  - Assignment will be based on incremental emissions associated with the proposed DEP regulations

Accounting for Emissions from Imports (*continued*)

- Massachusetts load based on 2016 CELT Forecast
- Massachusetts imports
  - Massachusetts load minus Massachusetts generation equal imports
    - If the carbon adder associated with the proposed DEP regulations decreases generation within Massachusetts, imports will increase
  - Imports will be allocated the incremental emissions associated with the energy shifted outside of Massachusetts

Accounting for Emissions from Imports (*continued*)

- Incremental emission rate for imports calculated by
  - Difference between generation outside Massachusetts:
    - Reference case
    - Case with additional Massachusetts allowance price
  - Difference between CO_2 emissions outside Massachusetts:
    - Reference case
    - Case with additional Massachusetts allowance price

$$\text{Incremental emission rate} = \frac{\text{Difference in Emissions Outside MA}}{\text{Difference in Energy Generation Outside MA}}$$

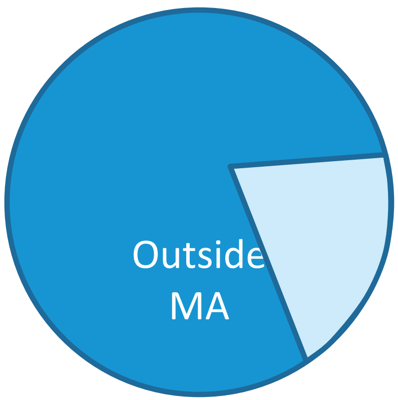
- Incremental emission rate applied to incremental import energy
- Emissions associated with non-cap case imports held constant

Illustration of Accounting for Import Emissions

Reference Case

Outside MA Gen: 101,573 GWh
Outside MA CO_2: 29,387 k-tons CO_2
Average CO_2 Emission Rate = 579 lb-CO_2/MWh

MA Gen: 50,692 GWh
MA CO_2: 9,221 k-tons CO_2



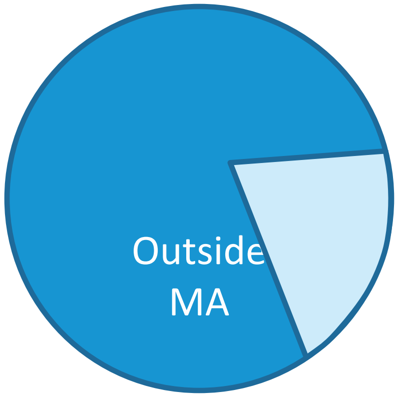
MA Imports: 21,347 GWh

CO_2 Associated with MA Imports: 6,176 k-tons
Based on 579 lb-CO_2/MWh

Reference Case w/Cap)

Outside MA Gen: 102,909 GWh
Outside MA CO_2: 30,051 k-tons CO_2
Incremental non-MA CO_2 Emission Rate = 993 lb-CO_2/MWh
Note: 993 lb-CO_2/MWh = (30,051 – 29,387) / (102,9093 – 101,573) * 2000

MA Gen: 49,354 GWh
MA CO_2: 8,650 k-tons CO_2



MA Imports: 22,685 GWh (21,347 + 1,338 GWh)

CO_2 associated with MA Imports: 6.840 k-tons (6,176 + 664 k-tons)
Emissions for incremental imports based on 993 lb-CO_2/MWh

Emissions Associated with Reference Imports

- Emissions associated with imports in the "without cap" case are held constant in evaluating the proposed DEP regulations
  – Holds the emissions outside of Massachusetts constant
  – All changes due to the proposed DEP regulations are therefore assigned to the incremental impact
- Import emissions are calculated based on
  – Net imports in the "without cap" case and the "without cap" import emission rate
  – "Without cap" import emission rate is average of non-Massachusetts generation

Case Description	MA Net Energy Requirement	MA Net Generation (GWh)	MA Net Imports (GWh)	Average Non-MA Emission Rate for Reference Import Emissions (lb-CO2 / MWh)	Reference Import Emissions Using Average Non-MA Reference (K Short Tons)
Reference Case	72,040	50,692	21,348	579	6,176
Reference Case + Hydro	72,040	55,044	16,996	561	4,768
Reference Case + Hydro + Wind	72,040	57,440	14,600	533	3,893
Retirement Case	72,040	51,505	20,535	512	5,257
Retirement Case + Hydro	72,040	55,358	16,682	497	4,144
Retirement Case + Hydro + Wind	72,040	58,385	13,655	470	3,206

Total Massachusetts Allocated Emissions Including Imports

- Total emissions allocated to Massachusetts are shown in the table below
  - Emissions associated with "without cap" case imports
  - Incremental emissions associated with proposed DEP regulations
    - Increase in imported energy, incremental emission rate
  - Emissions from resources physically located in Massachusetts
- All cases show:
  - Net increase in Massachusetts emissions
  - Net increase in New England emissions
  - Zero increase in non-Massachusetts emissions

A	B	C	D	E	F	G	H	I	J
			(B) + (C)				(E) + (F) + (G)	(H) - (D)	
	Reference			With Proposed DEP Regulations					
Case Description	Reference Import Emissions Using Average Non-MA Without Cap (K Short Tons)	Emissions from MA Physical Generation (K Short Tons)	MA Allocated CO2 Emissions (K Short Tons)	Reference Import Emissions Using Average Non-MA Reference (K Short Tons)	Incremental Import Emissions at Incremental Rate (K Short Tons)	Emissions from MA Physical Generation (K Short Tons)	MA Allocated CO2 Emissions (K Short Tons)	**Increase in MA Allocated Emissions (K Short Tons)**	**Increase in Non-MA Share of Emissions (K Short Tons)**
Reference Case	6,176	9,221	15,397	6,176	664	8,650	15,490	**93**	**0**
Reference Case + Hydro	4,768	8,153	12,921	4,768	1,017	7,272	13,057	**136**	**0**
Reference Case + Hydro + Wind	3,893	7,137	11,030	3,893	842	6,384	11,119	**89**	**0**
Retirement Case	5,257	9,557	14,814	5,257	775	8,848	14,880	**66**	**0**
Retirement Case + Hydro	4,144	8,297	12,441	4,144	1,110	7,260	12,514	**73**	**0**
Retirement Case + Hydro + Wind	3,206	7,531	10,737	3,206	772	6,793	10,771	**34**	**0**

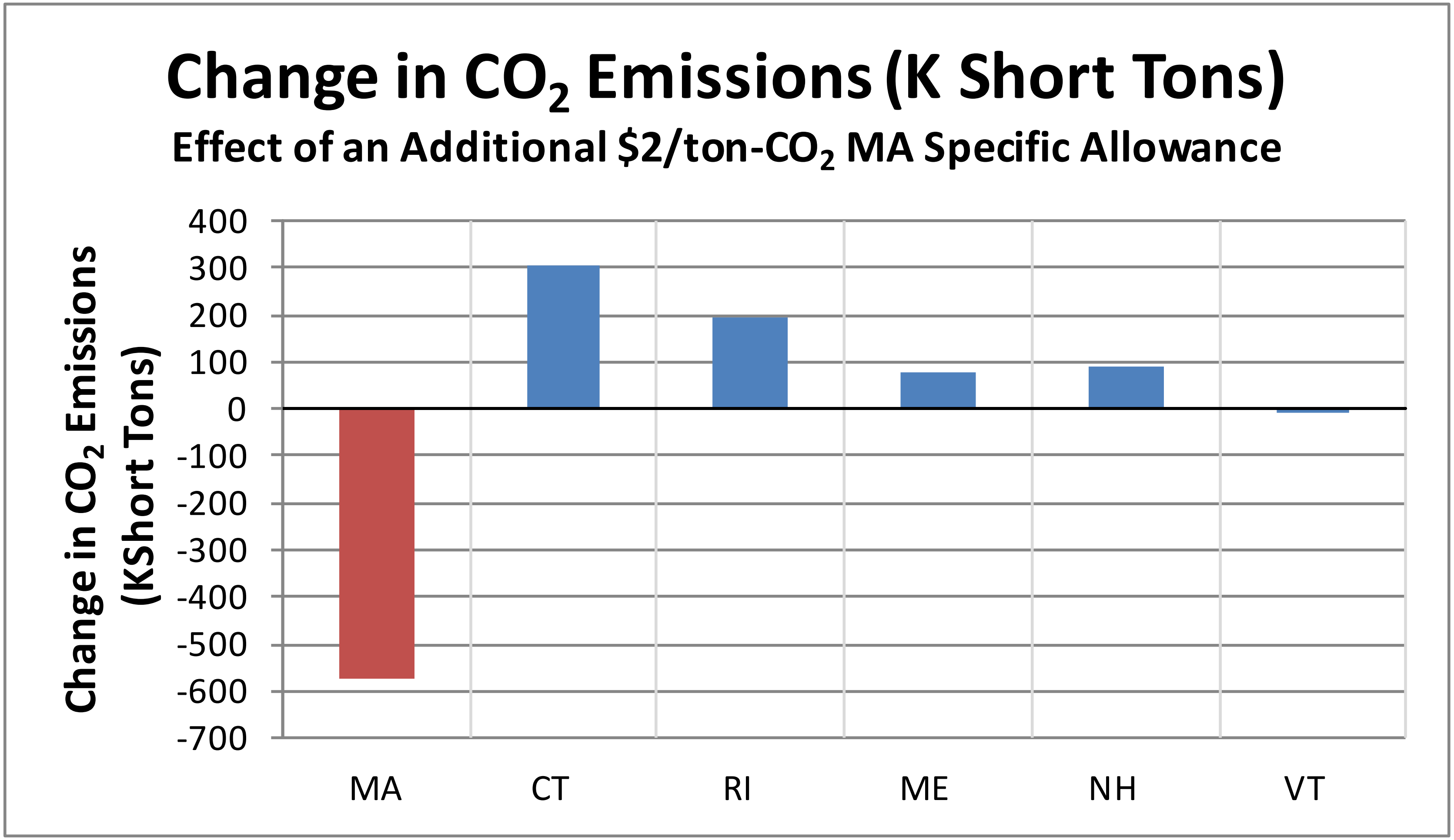
Relative Emission Rates for Imports vs. Decremental MA Generation

- Massachusetts decremental emission rate is lower than incremental emission rate outside of Massachusetts
  - Decreasing Massachusetts generation and replacing that energy with imports results in an increase in emissions
  - Incremental imported energy has an emission rate 5 to 16 percent higher than the Massachusetts decremental emission rate

Case Description	Incremental Import Emission Rate (lb-CO2 / MWh)	MA Decremental Emission Rate (lb-CO2 / MWh)	Imported Emission Rate to MA Decremental Emissions Rate (Percent)
Reference Case	993	854	116%
Reference Case + Hydro	973	843	115%
Reference Case + Hydro + Wind	966	864	112%
Retirement Case	926	848	109%
Retirement Case + Hydro	905	845	107%
Retirement Case + Hydro + Wind	889	850	105%

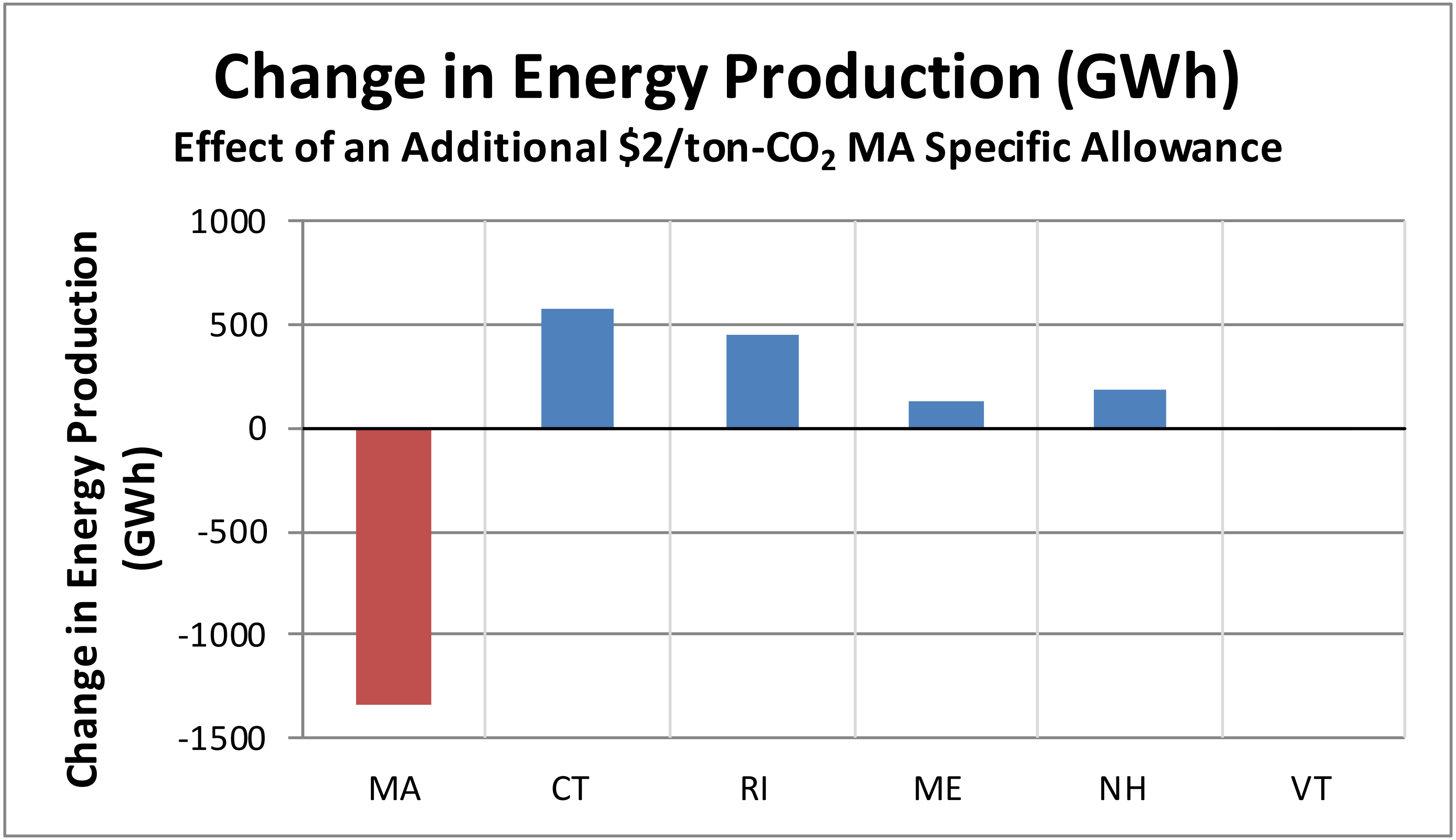
State Level Change in CO_2 Emissions

Effect of an Additional \$2/ton-CO_2 MA Specific Allowance



State Level Change in Energy

Effect of an Additional \$2/ton-CO_2 MA Specific Allowance



State Level Change in Energy and CO_2 Emissions

Effect of an Additional \$2/ton-CO_2 MA Specific Allowance

State	Change in Energy Production (GWh)	Change in CO2 Emissions (K Short Tons)	Average Emission Rate (lb/MWh)	Incremental / Decremental
MA	-1,338	-571	854	Decremental
CT	574	303	1,056	Incremental
RI	452	196	867	Incremental
ME	131	79	1,206	Incremental
NH	180	89	989	Incremental
VT	-1	-1	N/A	Change Too Small
New England*	0	93		

* Totals may not equal the sum of the individual state values due to rounding.

ADDITIONAL INFORMATION

Scenario Data for Emissions and Generation Imports into Massachusetts

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
	Input Assumption	Extracted From Model Results	Extracted From Model Results	(C) + (D)	(B) - (E)	Difference in Column (F)	Note 1	Note 2	Extracted From Model Results	Extracted From Model Results	(J) + (K)	(H) + (I) + (L)	Difference in Column (M)	Extracted From Model Results	Difference in Column (O)	Extracted From Model Results	Difference in Column (Q)
	MA Net Energy Requirement	MA Affected Generation	MA Non-Affected Generation and HVDC	MA Net Generation	MA Net Import / Export	Incremental Imports	Reference Import Emissions Using Average Non-MA Without Cap	Incremental Import Emissions at Incremental Rate	Emissions From MA Affected Generation	Emissions From MA Non-Affected Generation	Emissions from MA Physical Generation	MA Allocated CO2 Emissions	Effect on MA Allocated Emissions (Increase is positive)	New England Total Carbon Emissions	Difference in Total New England Emissions	New England LMP	Increase in New England LMP
	GWh	GWh	GWh	GWh	GWh	GWh	K Short Tons	K Short Tons	K Short Tons	K Short Tons	K Short Tons	K Short Tons	K Short Tons	K Short Tons	K Short Tons	$/MWh	$/MWh
Reference Case	72,040	16,960	33,732	50,692	21,348	N/A	6,176		7,471	1,750	9,221	15,397		38,608		46.46	
Reference Case w/Cap (at $2/ton)	72,040	15,593	33,761	49,354	22,686	1,338	6,176	664	6,870	1,780	8,650	15,490	93	38,701	93	46.65	0.19
Reference Case + Hydro	72,040	14,703	40,341	55,044	16,996	N/A	4,768		6,451	1,702	8,153	12,921		35,427		45.81	
Reference Case + Hydro w/Cap (at $2/ton)	72,040	12,568	40,385	52,953	19,087	2,091	4,768	1,017	5,527	1,745	7,272	13,057	136	35,563	136	46.16	0.35
Reference Case + Hydro + Wind	72,040	12,524	44,916	57,440	14,600	N/A	3,893		5,503	1,634	7,137	11,030		32,419		44.22	
Reference Case + Hydro + Wind w/Cap (at $2/ton)	72,040	10,775	44,922	55,697	16,343	1,743	3,893	842	4,734	1,650	6,384	11,119	89	32,508	89	44.19	-0.03
Retirement Case	72,040	17,744	33,761	51,505	20,535	N/A	5,257		7,777	1,780	9,557	14,814		35,349		46.97	
Retirement Case w/Cap (at $2/ton)	72,040	16,036	33,796	49,832	22,208	1,673	5,257	775	7,033	1,815	8,848	14,880	66	35,415	66	47.22	0.25
Retirement Case + Hydro	72,040	14,955	40,403	55,358	16,682	N/A	4,144		6,538	1,759	8,297	12,441		32,368		46.64	
Retirement Case + Hydro w/Cap (at $2/ton)	72,040	12,465	40,440	52,905	19,135	2,453	4,144	1,110	5,464	1,796	7,260	12,514	73	32,441	73	46.98	0.34
Retirement Case + Hydro + Wind	72,040	13,402	44,983	58,385	13,655	N/A	3,206		5,857	1,674	7,531	10,737		29,570		45.58	
Retirement Case + Hydro + Wind w/Cap (at $2/ton)	72,040	11,636	45,012	56,648	15,392	1,737	3,206	772	5,086	1,707	6,793	10,771	34	29,604	34	45.58	0.00

Note 1: Reference Import Emissions are based on the imported GWh from the case without a cap and the average CO2 emissions for the non-Massachusetts GWh.

Note 2: Incremenmtal Import Emissions are based on the change in non-Massachusetts GWh and non-Massachusetts CO2 emissions between the with and without cap cases.

2016 Load Forecast Shows Slow Growth After PV and Passive Demand Response

ISO-NE	50/50 SUMMER PEAK (MW)			50/50 WINTER PEAK (MW)			ANNUAL ENERGY (GWh)		
	GROSS	GROSS-PV	GROSS-PV-PDR	GROSS	GROSS-PV	GROSS-PV-PDR	GROSS	GROSS-PV	GROSS-PV-PDR
2016	28966	28543	26704	22992	22992	21340	140269	138968	128014
2017	29307	28788	26698	23170	23170	21338	141997	140342	128439
2018	29652	29070	26765	23353	23353	21183	143775	141877	128598
2019	29975	29344	26783	23507	23507	21136	145268	143171	128261
2020	30276	29601	26789	23633	23633	21029	146486	144208	127407
2021	30578	29863	26816	23758	23758	20937	147706	145262	126695
2022	30883	30137	26870	23890	23890	20865	148982	146400	126180
2023	31190	30415	26942	24022	24022	20807	150267	147554	125790
2024	31493	30691	27026	24151	24151	20758	151513	148677	125468
2025	31794	30966	27122	24276	24276	20717	152731	149772	125213
2020 to 2025			333			-312			-2194

MA State	50/50 SUMMER PEAK (MW)			50/50 WINTER PEAK (MW)			ANNUAL ENERGY (GWh)		
	GROSS	GROSS-PV	GROSS-PV-PDR	GROSS	GROSS-PV	GROSS-PV-PDR	GROSS	GROSS-PV	GROSS-PV-PDR
2016	13418	13168	12326	10603	10603	9803	64860	64092	59145
2017	13592	13296	12219	10701	10701	9695	65772	64829	58936
2018	13770	13457	12224	10804	10804	9651	66740	65719	58702
2019	13938	13618	12230	10896	10896	9624	67597	66532	58591
2020	14097	13773	12239	10973	10973	9568	68330	67236	58226
2021	14255	13927	12258	11050	11050	9521	69061	67938	57934
2022	14415	14082	12287	11130	11130	9485	69819	68667	57738
2023	14575	14238	12325	11211	11211	9458	70580	69399	57610
2024	14734	14392	12370	11289	11289	9436	71319	70110	57520
2025	14891	14544	12421	11365	11365	9419	72040	70802	57467
2020 to 2025			182			-149			-759

Methodology Used by ISO New England in an Analysis of DEP's Proposed Emission Cap Regulations

1. Methodology

The ISO conducted a parametric study by simulating the New England bulk electric power system's electricity production for the year 2025 with and without the carbon emission allocations imposed under the proposed DEP regulations applicable to the Massachusetts affected generating resources. The carbon emission allocations are managed in the simulations by applying an "adder" to the production costs of the Massachusetts affected units. The study used the ABB GridView electricity production simulation program (please see description in Appendix) that models the hourly electricity production of the New England system including system operating procedures and energy market rules.

By comparing the cost and generation results of the cases with and without the imposition of the carbon emissions allocations, the impact of the proposed regulations can be identified.

Note: this analysis is designed to obtain a high level, directional outcome and not the absolute value of the proposed CO_2 limitations.

2. New England Impact

The total CO_2 emissions associated with meeting the energy requirements of New England is the sum of the CO_2 emissions from all the emitting generating resources. By comparing the emission results of the cases with and without the proposed CO_2 limitations, the impact on CO_2 emissions associated with meeting New England energy needs can be identified.

3. Massachusetts Impact

The total CO_2 emissions associated with meeting the energy requirements for Massachusetts is calculated to be the sum of the CO_2 emissions from the units physically located in Massachusetts and CO_2 emissions associated with energy imported from generation located outside of Massachusetts to meet Massachusetts energy needs.

By comparing the emission results for the cases with and without the proposed CO_2 limitations, the impact on CO_2 emissions associated with meeting Massachusetts energy needs can be identified.

4. Accounting for Emissions Due to Imports

The CO_2 emissions associated with imports can be calculated in multiple ways. One approach to accounting for the incremental CO_2 emissions associated with the energy imports is to assign to Massachusetts all of the emissions that are over-and-above the reference case import levels. This is the approach used by ISO New England.

Another approach is to use the average CO_2 emissions per MWh of generation located outside of Massachusetts and calculate Massachusetts' share of CO_2 emissions based on the total amount of energy imported and this average emission rate.

5. Cases Simulated

Two reference resource scenarios from the ISO New England 2016 Economic Studies were used for this study.

- Scenario 4 which assumed the resources purchased in the Forward Capacity Auction for the Capacity Commitment Period 2019/2020 (FCA 10) are in service and no additional retirements of coal and oil generating resources beyond those accepted in FCA 10.
- Scenario 5 which assumed that the resources purchased in the Forward Capacity Auction for the Capacity Commitment Period 2019/2020 (FCA 10) are in service but with half of the coal and oil generating resources retired by 2025. The capacity shortfall are provided by new Natural Gas Combined Cycle (NGCC) units located at the same sites of the retired resources to satisfy the Net Installed Capacity Requirement (NICR).

Two sensitivities of additional renewable resources were simulated from these two reference resource scenarios:

- Additional 1,200 MW of hydro imports.
- Additional 1,200 MW of hydro imports combined with 1,600 MW of offshore wind resources.

From these scenarios and renewable resource sensitivities, GridView simulation cases were conducted for the following groups:

6. Reference Case

- Reference Case – Scenario 4 reference case where all RGGI units have an assumed carbon allowance adder of $19/ton
- Reference Case w/Cap – Scenario 4 where MAGWSA units have an adder of $21/ton while the rest of the RGGI units have an adder of $19/ton
- Reference Case + Hydro - Scenario 4 reference case with 1,200 MW of additional hydro imports where all RGGI units have an assumed carbon allowance adder of $19/ton

- Reference Case + Hydro w/Cap – Scenario 4 with 1,200 MW of additional hydro imports where MAGWSA units have an adder of $21/ton while the rest of the RGGI units have an adder of $19/ton
- Reference Case + Hydro + Wind - Scenario 4 reference case with 1,200 MW of additional hydro imports and 1,600 MW of offshore wind resources, where all RGGI units have an assumed carbon allowance adder of $19/ton
- Reference Case + Hydro + Wind w/Cap - Scenario 4 reference case with 1,200 MW of additional hydro imports and 1,600 MW of offshore wind resources, where MAGWSA units have an adder of $21/ton while the rest of the RGGI units have an adder of $19/ton

7. Retirement Case

- Retirement Case - Scenario 5 reference case where all RGGI units have an assumed carbon allowance adder of $19/ton
- Retirement Case w/Cap – Scenario 5 where MAGWSA units have an adder of $21/ton while the rest of the RGGI units have an adder of $19/ton
- Retirement Case + Hydro - Scenario 5 reference case with 1,200 MW of additional hydro imports where all RGGI units have an assumed carbon allowance adder of $19/ton
- Retirement Case + Hydro w/Cap – Scenario 5 with 1,200 MW of additional hydro imports where MAGWSA units have an adder of $21/ton while the rest of the RGGI units have an adder of $19/ton
- Retirement Case + Hydro + Wind - Scenario 5 reference case with 1,200 MW of additional hydro imports and 1,600 MW of offshore wind resources, where all RGGI units have an assumed carbon allowance adder of $19/ton
- Retirement Case + Hydro + Wind w/Cap - Scenario 5 with 1,200 MW of additional hydro imports and 1,600 MW of offshore wind resources, where MAGWSA units have an adder of $21/ton while the rest of the RGGI units have an adder of $19/ton

8. Study Assumptions

Study assumptions are the same as those used in the Phase I of the ISO New England 2016 Economic Studies. Details of these assumptions are documented in the following presentation:

https://www.iso-ne.com/static-assets/documents/2016/06/a9_2016_economic_study_assumptions_stakeholder_comments.pdf

9. APPENDIX – The GridView Simulation Model

1. GridView Simulation Model

GridView is a software application developed by ABB Inc. to simulate the market operation of an electric power system with a constrained transmission system. As a market simulation tool, it can be used to analyze the utilization of transmission and generation assets, estimate market price signals, identify transmission system bottlenecks, evaluate the engineering and economic impact of changes in system configurations, such as transmission system expansion, the addition and retirement of supply resources, and changes in fuel prices.

GridView can be used to simulate the economic operation of a power system in hourly intervals for periods ranging from one day to many years. Typically these simulations are performed integrating aspects of the Day-ahead market with actual (e.g. real-time) data. To perform these simulations, GridView incorporates a detailed supply and demand model, superimposed on a transmission system model which allows a large–scale transmission grid representation. The Day-ahead market aspect is handled by the security-constrained unit commitment (SCUC) logic and the actual realized market aspect is handled by the security- constrained economic dispatch (SCED) of the system resources against spatially distributed loads. This allows GridView to produce a realistic forecast of the utilization of power system components and energy flow patterns across the transmission grid. To capture the inter-temporal constraints the simulation is run chronologically. The output information usually includes transmission and generator utilization, Locational Marginal Prices (LMP) for energy and ancillary services, and transmission bottleneck metrics. A system security assessment under contingency conditions can also be obtained from the results.

1.1 Modeling of Load

The 2025 load is based on the monthly peak and energy forecast from the CELT 2016 data using an hourly profile based on the historical 2006 load shape. GridView used the same hourly load profiles and distributed the loads to network buses in the 13 RSP areas.

1.2 Modeling of Resources

1.2.1 Thermal units

In GridView all thermal units in the ISO New England region are modeled as dispatchable units using summer and winter seasonal claimed capability (SCC) values. The thermal units are mapped to the transmission network locations in the PSS/E model according to Asset ID and plant name. However, for numerous small units whose location cannot be assigned to a specific network bus, aggregate units were defined. These aggregate units represent total capacities summed by fuel and technology and were placed within an appropriate RSP area.

One of the key inter-temporal constraints that GridView represents are ramp rates which changes how quickly a generator can change its output in a single hour.

There are no pre-specified energy limits for thermal units to represent fuel constraints.

For modeling thermal unit production cost, GridView cases use a detailed model that represents the start-up cost of a generator, the no-load cost (which represents the energy needed to keep all the equipment at the appropriate operating temperatures and all the ancillary equipment running) and incremental heat rates to represent the amount of energy required to produce the next MWh of energy once the generator is in an operating mode.

Modeling thermal unit unavailability is represented by derating the capacity by the amount of the generator's Equivalent Forced Outage Rate (EFORd). This EFORd is obtained from the ISO New England Generating Availability Data System (GADS).

The following describes how the nuclear, fast start and combined cycle units are modeled in GridView:

- Nuclear Unit - In GridView, nuclear units are modeled as must run but dispatchable units. Nuclear units are always committed (except for outages), but the output is dispatchable. If there is an excessive amount of wind; the nuclear resources can also be curtailed.
- Fast Start Unit - GridView models the start time of generating units. This allows resources that can provide reserves to be distinguished from the resources that cannot easily provide reserves.
- Combined cycle definition – GridView does not model dependencies between the component units in a combined cycle plant and assumes a single heat rate for the combined facility.

1.2.2 Conventional Hydro units

Conventional hydro units are scheduled to be dispatched using hourly profiles that are dispatched with a bias to generate more when the loads are highest and less when loads are lower. In this approach some energy is generated in every hour of each month. The highest output is associated with the monthly peak load. The market area's energy requirements are reduced by the amount of monthly hydro generation. When the hydro capacity factor is relatively low, effective hydro capacity may be significantly less than its installed capability. In these cases, hydro units are unlikely to be dispatched at full capacity during monthly peak load hours.

1.2.3 Pumped storage

In GridView, the pumped storage units are modeled as hourly resources whose output is based on a fixed profile. The fixed input profile represents both pumping to fill the pond and generation that depletes the storage pond while accounting for the losses associated with the storage.

1.2.4 Wind units

Wind resources included in this study had an obligation in FCA 10 or had an approved I.3.9 application. The resource nameplate capacities that were input were based on the queue reported MW values.

The wind profiles that were used in the analysis were based on the refined regional wind models developed under the New England Wind Integration Study. These profiles were developed for 8760 hours and were time-synchronized with the 2006 load shape model used.

In GridView, the wind units are modeled as an hourly resource. If several wind units are connected to the same PSS/E network location, they will be aggregated together and will have the same wind profile. Wind spillage is enabled in GridView to respect transmission constraints. When the LMP at the buses where the wind generators are connected reaches zero due to transmission constraints or excess wind, the wind output will be curtailed.

It should be noted that in the GridView modeling, even though a large amount of wind capacity was added, there was no strengthening of the transmission network to accommodate this increase in wind. This may result in significant congestion which will be discussed later.

1.2.5 Active Demand Resources and Energy Efficiency

Active Demand Resources (DR) and Energy Efficiency (EE) are modeled through pre-specified profiles based on the original load profile. A total of 3,844 MW of EE has been modeled for the region in 2025, which is in consistent with the forecasted EE amount in the 2016 ISO New England's Capacity, Energy, Loads, and Transmission (CELT) Report.

1.2.6 Photovoltaics

PV is modeled based on the ISO's Final 2016 PV Forecast. The region has a cumulative nameplate capacity of 3,273 MW of PV by 2025. The forecasted values include Forward Capacity Market (FCM) Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources.

1.2.7 Imports and exports

For import and export modeling with neighboring systems, GridView uses values based on historical imports and export. To represent interchange with these external areas, typical diurnal profiles for New York, Quebec and New Brunswick (Maritimes) were developed based on historical flows from three years. This approach captured the characteristics observed within the historical data and summarized the flows by month throughout the year. These profiles represented interconnection points for:

- Hydro Quebec
  - Highgate and
  - Phase II HVDC
- New York
  - Cross Sound Cable

- Norwalk-Northport (NNC)
- Aggregate free-flowing AC interconnections

- New Brunswick

The typical diurnal profile developed for each interconnection point is the same in all cases of this study. Therefore, imports and exports with neighboring systems are fixed across all cases.

1.2.8 Operating Reserve Requirement

In the GridView Transmission Modeling and Refined Modeling cases, the current ISO reserve requirement is enforced. This requires that the total ten minute reserve equals 125% of the largest contingency. Of this total ten minute reserve requirement, 50 percent must be held in committed and spinning resources (TMSR). The remaining 50 percent of the ten minute reserve can be held in units that are off-line, but which are designated as "fast-start-units" (TMNSR).

Because the study year is a future year a fixed value was selected to represent the largest contingency. Currently in ISO operations, the largest single source contingency is usually either HQ Phase II HVDC, or Mystic 8 and 9 combined, whichever is larger. The largest single source contingency is around 1400 MW, and 125% of it is 1,750 MW. Therefore, in these cases, the ten-minute committed and spinning reserve requirement (TMSR) is set at 50 percent of this amount, or 875MW. The remaining ten minute reserve (TMNSR) can be satisfied by conventional hydro, pumped storage and quick start units. Because this is unlikely to affect the economic metrics, TMNSR is not modeled.

Similarly, the thirty minute operating reserve requirement (TMOR) is unlikely to affect the economic metrics and is not modeled.

1.3 Modeling of Transmission System

1.3.1 Transmission network

The study used the pipe and bubble model to simulate the New England transmission system. The ISO New England system is divided into 13 Regional System Plan (RSP) areas with interfaces between groups of areas. The interface limits between these areas are enforced to constrain the power transfer across New England. Within each RSP area, it is assumed that the transmission network is adequate to handle any level of power flows not limited by the specified interface limits.

Interchange of energy between New England and the neighboring systems is modeled through imports / exports using dummy generators at external interface points. These injections and withdrawals are distributed to pre-defined interface lines, based on line ratings.

1.4 Modeling of Fuel Prices

1.4.1 U.S. Energy Information Administration (EIA) forecasted fuel prices

The study used the EIA forecasted fuel prices for the year of 2025 in the New England region, as published in EIA's Annual Energy Outlook 2016. Table 1 listed the modeled fuel prices.

Table 1.2025 New England Fuel Prices Modeled

Fuel Types / Year	2025
Distillate Fuel Oil (2015$/MMBtu)	20.749
Residual Fuel Oil (2015$/MMBtu)	13.149
Natural Gas (and LNG) (2015$/MMBtu)	5.390
Steam Coal (2015$/MMBtu)	2.721

1.4.2 Seasonal Natural Gas (NG) Price Adjustment

A monthly natural gas multiplier has been applied to reflect the seasonal natural gas prices differences: higher NG prices in the winter months and lower NG prices during the summer months. Figure 1 illustrated the applied monthly natural gas multiplier.

Figure 1.Monthly Natural Gas Multiplier Applied