A Clean Energy Standard for Massachusetts

Final Report

Prepared for MassCEC and the Agencies

October 25, 2013

AUTHORS

Elizabeth A. Stanton, PhD
Sarah Jackson
Geoff Keith
Erin Malone
David White
Tim Wolff

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

1. EXECUTIVE SUMMARY

A Clean Energy Standard designed as a share-of-sales requirement on retail electricity suppliers can be a viable, cost-effective option for Massachusetts as long as generation resources that will not contribute to new greenhouse gas emission reductions do not receive windfall payments.

This report describes Synapse Energy Economics' (Synapse) analysis of the Clean Energy Performance Standard described in the Global Warming Solutions Act's *Massachusetts Clean Energy and Climate Plan for 2020* (CECP) on behalf of MassCEC and the Massachusetts Departments of Energy Resources, Environmental Protection, and Public Utilities (the "Agencies"). Throughout this report we refer to the Clean Energy Performance Standard as a "Clean Energy Standard" (CES) to emphasize that policy designs under consideration include both performance standards and portfolio standards.

Analysis of the CECP's Clean Energy Standard

The specific issues designated for study by MassCEC and the Agencies included:

- The approach, successes, difficulties and status of CESs in jurisdictions other than Massachusetts;
- Qualitative advantages and disadvantages of various approaches to implementing a CES to reduce greenhouse gas emissions from the electricity sector; and
- Costs and greenhouse gas emission reductions that could be achieved from various levels of or approaches to a CES, using transparent assumptions consistent with existing programs in Massachusetts that are reducing or will reduce greenhouse gas emissions from the electricity sector.

After examining CES policy designs implemented in the United Kingdom, Canada, and six U.S. states, and making a qualitative assessment of six potential CES designs for Massachusetts, Synapse—in consultation with MassCEC and the Agencies—selected the design that was both politically viable and technically feasible for further modeling: a portfolio standard requiring load-serving-entities (LSEs) to purchase Clean Energy Certificates (CECs) equal to a designated share of their retail sales. This approach would require a system of tradable credits; eligible generators would generate a CEC (or a portion of a CEC) with each megawatt-hour (MWh) produced. Compliance verification could be accomplished with modifications to existing reporting systems. This design closely resembles the existing Renewable Portfolio Standard (RPS) in Massachusetts.

A performance standard sets a limit on the amount of emissions that can be released per unit of electricity generated.

A portfolio standard requires electricity distributors to purchase certificates from qualifying low-emissions generators equal to a given share of their sales.

Power-plant-based pounds (lbs) per MWh performance standards, limitations to or requirements on electricity-sector contracts, and requirements on electricity suppliers to purchase Regional Greenhouse Gas

Initiative allowances were all removed from consideration as potential CES designs for Massachusetts on grounds of a lack of political viability or particular technical obstacles to implementation in the Commonwealth. LSE-based lbs/MWh performance standards have not been proposed or established in any other jurisdiction, and come with significant administrative and design hurdles, and were also removed from consideration. LSE-based performance standards were not found to possess any advantage over LSE-based portfolio standards in terms of their technological neutrality or vulnerability to resource shuffling:

- ***Both performance and portfolio standards can be designed to be "technology neutral"—or not.*** (A CES policy is technology neutral if all electricity generating technologies are allowed to participate, and their participation is managed by a technology independent criterion such as carbon intensity, as opposed to a CES policy that does not allow certain technologies to participate.) Either a performance or portfolio standard could be designed to achieve a certain emission reduction goal instead of being benchmarked against a particular generation technology.

- ***Resource shuffling is unavoidable for LSE-based performance and portfolio standards in New England, but a well-designed Massachusetts CES can succeed despite shuffling.*** (Shuffling refers to a situation in which LSEs can comply with a CES standard simply by acquiring energy from a different existing generator or acquiring credits from existing generators.) CES eligibility terms must ensure a "binding" policy—a CES that cannot be complied with solely by shuffling CECs from existing generation.

Design of Synapse's CES Policy Model

We designed the CES Policy Model to demonstrate the impacts of an LSE-based portfolio standard on emission reductions and costs to ratepayers. The model's Reference Case assumes that all CECP electricity-sector emission reduction strategies, except the Clean Energy Imports strategy and the Clean Energy Performance Standard, will be accomplished. The sole difference between the Reference and Policy Cases is the implementation of a CES. Model results depend both on the basic type of CES design chosen and on the details assumed regarding its implementation in the model.

Three key simplifying assumptions were made in order to produce a model with sufficient flexibility to provide MassCEC and the Agencies with a tool that could be used to explore a wide range of policy assumptions, without significant per-scenario costs:

1. CECs assigned to generation resources and purchased by LSEs have the same price as Renewable Energy Credits (RECs). This assumption is driven, in part, by the high future demand for renewables expected to come as a result of Massachusetts' ambitious existing Renewable Portfolio Standard policy.

2. CEC purchases stimulate investment in new zero-carbon resources and imports, thereby displacing existing natural gas generation. The CES does not stimulate more natural gas generation or displace existing coal and oil, which are very nearly retired by 2030 in the Reference Case.

3. The mix of the various zero-carbon resources and imports added will be a policy choice and is, therefore, a fixed input into the model—and not an output, or policy conclusion, of the model.

A different policy design choice or different implementation strategy might result in different costs or changes to other modeling results. The rationale behind these assumptions is discussed in detail in the report.

CES Policy Model results also depend on user choices. The results presented here are based on modeling "runs" using varying assumptions regarding assigning CECs to particular types of resources, requiring municipal light plants (MLPs) to comply with a CES, the share of LSEs' sales requiring CECs, the future growth of retail electricity sales, and emission reduction targets. All model runs shown here, however, use identical assumptions for all other modeling parameters including assessing policy implementation for 2020 and 2030, and implementation in Massachusetts only.

The policy targets explored in our analysis included GWSA electricity-sector target emissions levels (12,400 short tons (sT) in 2020 and 8,400 sT in 2030), and emission reductions equal to 0.5, 1.0, and 2.0 times the emission reductions expected from the Clean Energy Imports strategy in the CECP (5.5 million sT). Modeling results are presented as "deltas," or the difference between Policy Case and Reference Case results.

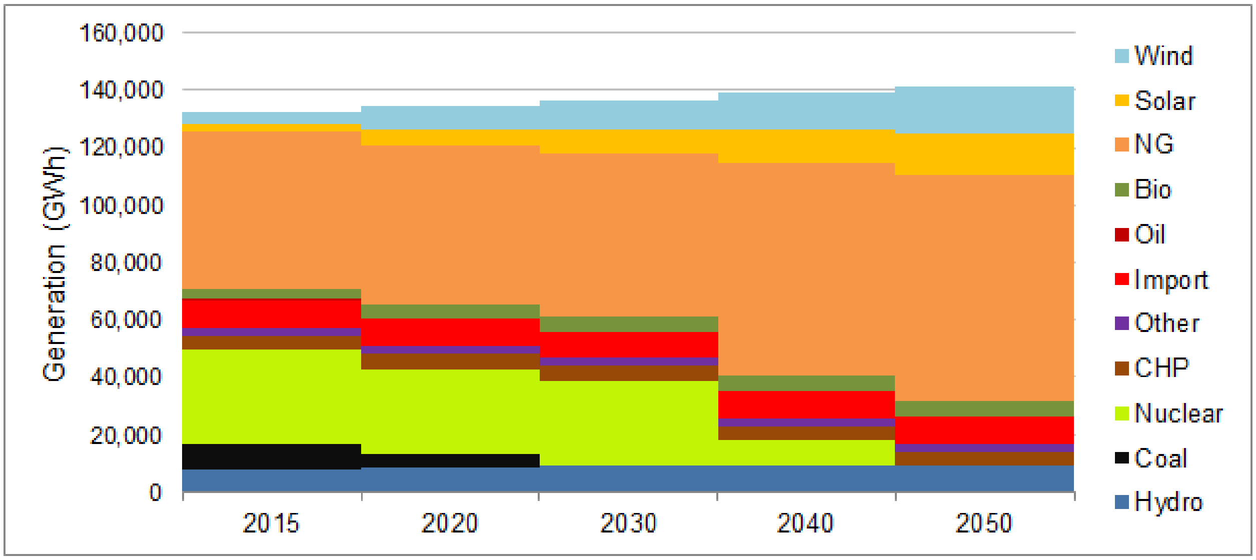
Key Conclusions from CES Policy Model Analysis

Overall, our analysis concludes that a CES designed as an LSE portfolio standard can be a viable, cost-effective option for Massachusetts as long as "windfall" CEC payments are not made to owners of resources, such as nuclear and natural gas, that will not (in the policy as modeled) contribute to new (additional) greenhouse gas emission reductions. Exploration of CES Policy Model results under various combinations of assumptions resulted in the following five findings:

CES Modeling is Not Viable for Years Later than 2030

Given current plant licenses, it seems likely that by 2050 there will be no nuclear generation facilities operating in New England. The loss of 22 percent of expected 2030 generation will be a massive, unprecedented planning challenge for New England. It is far more likely that the fuel mix of the resources necessary to replace nuclear generation will be determined by policy choices than by the dynamics of a potential future CES market. In the CES Policy Model, 2040 and 2050 results are swamped by the assumption that natural gas will replace exiting nuclear generation in the Reference Case. For this reason, we do not present Policy-Case modeling results for 2040 and 2050 in this report.

Figure ES-1. Reference Case Generation Mix



The Share of Sales Requiring CECs Determines the Cost to Ratepayers

Customer utility bill increases due to CES are determined by the stringency of the requirement on LSEs—what share of load they must cover with CEC purchases, and whether or not MLPs are required to comply. What resources are assigned how many credits has little impact on the price to consumers (with the exception of an alternative formulation of the CES policy discussed below). Choosing a constant CEC threshold (such that generators with an CO_2 emission rate above the threshold do not qualify to be assigned CECs) and varying the share of LSEs' sales required to hold CECs allows for more flexibility in costs to rate payers and in the range of achievable emission reductions. In the scenarios that follow we have set the CEC threshold to 2,000 lbs/MWh. Except where mentioned explicitly, all modeling results discussed in this report are based on achieving the emission reductions expected from the Clean Energy Imports strategy in the CECP (5.5 million sT).

CES Does Not Reduce Emissions If Nuclear Power is Assigned CECs

The likely outcome of including nuclear generation in a CES would be windfall profits to nuclear facilities. Providing rewards to nuclear plants will not increase nuclear generation in New England. With nuclear facilities assigned CECs, there is no change in regional emissions, but residential customers nonetheless see their utility bills grow by 4 percent in 2020 and 6 percent in 2030 with respect to the Reference Case (see Table ES-1). The remaining scenarios shown below assume that existing nuclear generation will not be assigned CES credit.

Table ES-1. CES Delta Bill Impacts: Includes Nuclear and Includes MLPs

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	4%	6%
Commercial	0%	4%	6%
Industrial	0%	5%	7%

Excluding MLPs from Compliance Raises Costs

Costs and emission reductions depend, in part, on whether or not MLPs are required to comply with the CES. If MLPs are excluded from compliance, the cost to ratepayers would be higher to achieve the same emission reduction. With MLPs included, costs to residential ratepayers grow by 6 percent in 2020 and 10 percent in 2030 with respect to the Reference Case. With MLPs excluded, ratepayers costs grow by 7 percent in 2020 and 11 percent in 2030 with respect to the Reference Case (see Tables ES-2 and ES-3).

Table ES-2. CES Delta Bill Impacts: Excludes Nuclear and Includes MLPs

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	6%	10%
Commercial	0%	6%	9%
Industrial	0%	7%	10%

Table ES-3. CES Delta Bill Impacts: Excludes Nuclear and MLPs

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	7%	11%
Commercial	0%	7%	11%
Industrial	0%	8%	12%

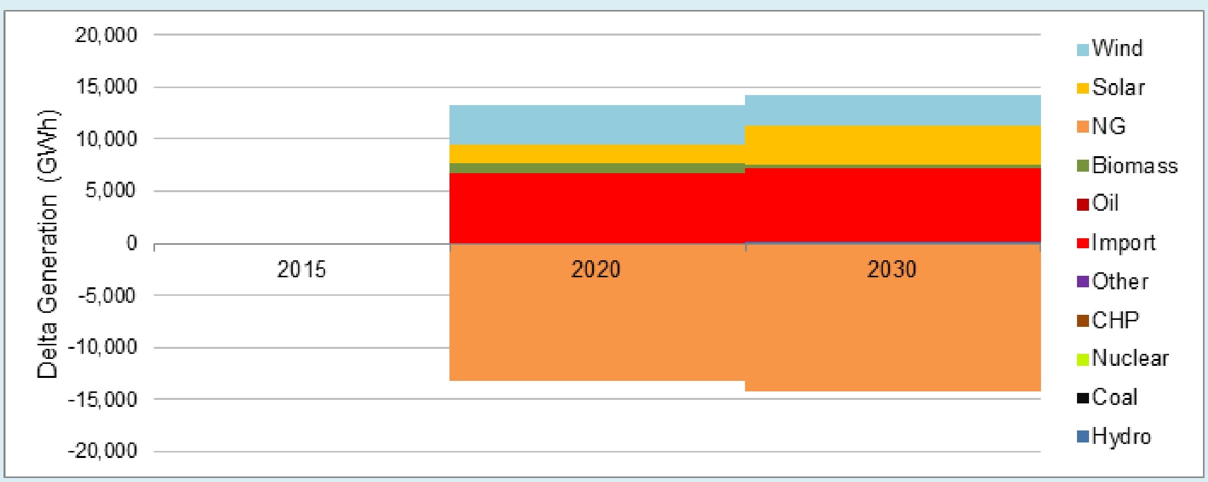
The remaining scenarios shown in this report assume that MLPs will comply with CES. Table ES-4 displays the base result: nuclear generation is excluded from receiving CECs; MLPs are required to comply; and the CEC threshold is set at 2,000 lbs/MWh. In this scenario, LSEs must be required to hold CECs for 73 percent of their sales in 2020 and 82 percent in 2030 in order to achieve a 5.5 million sT target emission reduction. Residential customers' monthly utility bills rise by 6 percent with respect to the Reference Case in 2020 and 10 percent in 2030.

Table ES-4. CES Delta Results: Excludes Nuclear and Includes MLPs; Threshold = 2,000 lbs/MWh

Delta Emissions		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	-7,093	-7,635
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-5,467	-5,467
Massachusetts Consumption CO_2 Emissions Rate	lbs/MWh	0	-177	-173

Delta New England Costs		2015	2020	2030
Supply	GWh	0	0	0
Fuel Costs	M$	0	-166	-312
CO_2 Costs	M$	0	-75	-81
VOM Costs	M$	0	-42	-49
Variable Costs of All Resources	M$	0	-283	-441
Variable Costs of All Resources	$/MWh	0.0	-2.1	-3.2
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	35,853	36,753
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		659.7	1,039.4
Total CES Cost per MWh Sales	$/MWh		10.7	16.4

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	6%	10%
Commercial	0%	6%	9%
Industrial	0%	7%	10%



Assigning CECs to Natural Gas Raises Costs

Because the 2015 Massachusetts average emission rate (660 lbs/MWh) is lower than the average of the combined-cycle plants that represent the vast majority of natural gas resources in New England (1,080 lbs/MWh), the CES cannot achieve emission reductions by stimulating more dispatch of or new investment in natural gas resources. CEC prices paid to natural gas generators, therefore, are a windfall: these resources' owners would receive payments without changing dispatch or investing in new resources.

Excluding resources with emission rates greater than the 2015 Massachusetts average from receiving CECs would have dramatic results; the effect of this exclusion, of course, is to preclude natural gas generators from receiving CECs. With the same assumptions as shown above in Table ES-4—nuclear excluded and MLPs required to comply—an additional exclusion of resources with emission rates greater than 660 lbs/MWh lowers both the share of sales requiring CECs and costs to ratepayers (see Table ES-5).

Table ES-5. CES Delta Results: With 660 lbs/MWh Cap on Resources Receiving CECs

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	2%	2%
Commercial	0%	2%	2%
Industrial	0%	2%	3%

In this scenario, with natural gas resources excluded from receiving CES credit, the share of sales for which LSEs are required to hold CECs falls to 29 percent in 2020 and 39 percent in 2030. Residential customers' utility bills increase by just 2 percent with respect to the Reference Case in both 2020 and 2030, in comparison to 6 and 10 percent, respectively, with natural gas participating in the CES. Natural gas is still displaced, and emissions still fall by 5.5 million sT, but no CES payments are made to the natural gas plants that continue to operate.

In This Report

This report begins in Section 2 with a brief overview of Synapse's analysis of potential CES policies for Massachusetts, along with the key policy conclusions and other findings that were developed as a result of our CES modeling exercise. Sections 3, 4, and 5 provide a description of our study of CES design options, presented in the order in which this analysis was conducted. Sections 3 reviews our research into CES policies in jurisdictions other than Massachusetts. Section 4 recounts our qualitative analysis of six potential CES designs for Massachusetts, and the process of narrowing these options down to the one design—the LSE-base portfolio standard—explored in modeling. The report concludes with Section 5, which describes the methodology and data used in the CES modeling exercise in detail, reports on sensitivity analyses, and offers caveats with regards to the use of the CES Policy Model results.

2. OVERVIEW AND FINDINGS OF THE CES POLICY MODEL

Synapse Energy Economics (Synapse) was engaged by MassCEC and the Massachusetts Departments of Energy Resources, Environmental Protection, and Public Utilities (the "Agencies") to analyze the advantages and disadvantages of various approaches to implementing the Clean Energy Performance Standard described in the Global Warming Solutions Act's[1] (GWSA's) *Massachusetts Clean Energy and Climate Plan for 2020*[2] (CECP). Throughout this report we refer to the Clean Energy Performance Standard as a "Clean Energy Standard" (CES) to emphasize that policy designs under consideration include both "performance standards" and "portfolio standards." The specific issues designated for study by MassCEC and the Agencies included:

Throughout this report the CECP's Clean Energy Performance Standard is referred to as a "Clean Energy Standard" (CES) to emphasize that not all such standards are designed as power-plant-directed "performance" regulations.

- The approach, successes, difficulties and status of CESs in jurisdictions other than Massachusetts (see Section 3);
- Qualitative advantages and disadvantages of various approaches to implementing a CES to reduce greenhouse gas emissions from the electricity sector (see Section 4); and
- Costs and greenhouse gas emission reductions that could be achieved from various levels of or approaches to a CES, using transparent assumptions consistent with existing programs in Massachusetts that are reducing or will reduce greenhouse gas emissions from the electricity sector (see Section 5).

This report begins, here in Section 2, with a brief overview of the process by which the numerous possible CES policy designs were narrowed to the particular design—a portfolio standard in which prices for Renewable Energy Certificates (RECs) and prices for a new set of Clean Energy Certificates (CECs) are closely related—and the key conclusions drawn from the analysis performed for MassCEC and the Agencies. Additional sensitivity analysis on the results presented here is reported in Section 5.4.

2.1. Overview of Policy Design Selection

Our analysis for MassCEC and the Agencies began with a review of CES policy designs that have been implemented in the United Kingdom and Canada, and in six U.S. states, as well as several proposed and current U.S. federal standards. We identified six potential CES designs for Massachusetts, but narrowed these choices—for reasons of political and technical feasibility—to two types of standards that we then subjected to a more thorough qualitative assessment, as depicted in Table 1.

[1] Chapter 298 of the Acts of 2008. https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter298.

[2] Office of the Secretary of Energy and Environmental Affairs. December 2010. Massachusetts Clean Energy and Climate Plan for 2020. http://www.mass.gov/eea/docs/eea/energy/2020-clean-energy-plan.pdf

Table 1. Narrowing CES Policy Options

General Qualitative Assessment	Detailed Qualitative Assessment	Modeling Exercise
#1: Set Power Plant Emission Standards		
#2: Set an LSE Performance Standard	#2: Set an LSE Performance Standard	
#3: Set an LSE Portfolio Standard	**#3: Set an LSE Portfolio Standard**	**#3: Set an LSE Portfolio Standard**
#4: Limit Long-Term Contracts		
#5: Require Long-Term Contracts		
#6: Require LSEs to Buy RGGI Allowances		

The two policies designs that receive that most detailed qualitative analysis both require the compliance of Massachusetts retail electricity suppliers, or "load-serving entities" (LSEs):

> **LSE Performance Standard:** This CES design requires electricity suppliers to meet an average emission rate for their load. Qualitative analysis determined that compliance would be difficult to verify, even using the existing New England Power Pool (NEPOOL) Generation Information System (GIS) tracking system, as Massachusetts only has authority to require emissions reporting by in-state power plants, among other limitations.
>
> **LSE Portfolio Standard:** This CES design requires electricity suppliers to cover a given portion of their load with credits from relatively low- or no-carbon sources (e.g., CECs). This approach would require a system of tradable credits; eligible plants would generate a credit (or a portion of a credit) with each megawatt-hour (MWh) produced. As with Renewable Portfolio Standard (RPS) policies that require RECs, LSEs would be required to hold credits covering a defined percentage of their total sales. Compliance verification could be accomplished with modifications to the existing NEPOOL GIS reporting system.

More generally, the findings of our detailed qualitative analysis were as follows:

Resource shuffling is unavoidable for LSE performance and portfolio standards in New England, but a well-designed Massachusetts CES can succeed despite shuffling.

Because Massachusetts suppliers source their electricity from the larger Independent System Operator-New England (ISO-NE) supply region, there is the potential for "shuffling,"[3] such that LSEs could buy all of the certificates or credits they need from existing generators, operating at current generation levels, without any change in overall carbon dioxide (CO_2) emissions. Shuffling will occur to some degree, but a well-designed Massachusetts CES can, nonetheless, succeed.

CES eligibility terms must ensure a "binding" policy—a CES that cannot be complied with by simply shuffling certificates or credits from existing generation.

CES eligibility terms must ensure a "binding" policy—a CES that cannot be complied with by simply shuffling certificates or credits from existing generation. One approach would be to adjust the "stringency" of the CES

[3] Shuffling refers to a situation in which LSEs can comply with a CES standard simply by acquiring energy from a different existing generator or acquiring credits from existing generators. In the extreme case, the standard could be met without changing plant build/retirement decisions or the dispatch of existing plants.

(the maximum average emission rate or the share of load for which LSEs are required to purchase credits) to the degree that real changes in the region's dispatch order and/or built infrastructure are necessary in order for Massachusetts LSEs to comply with the CES.

Both performance and portfolio standards can be designed to be "technology neutral"—or not.

In weighing the performance and portfolio standards, it is important to recognize that both can be designed to be "technology neutral"—or not. While performance standards' criterion is a neutral metric (pounds (lbs) of CO_2 per MWh), the selection of the stringency will be made with full knowledge of the respective emissions rates of each resource type and class of plants. Setting a performance standard at 2,000 lbs/MWh (slightly lower than the typical emission rate of a conventional coal plant) will have a very different impact on dispatch by technology type than would a 800 lbs/MWh standard (slightly lower than the typical emission rate of a combined-cycle gas plant).

Either a performance or portfolio standard could be designed to achieve a certain goal—such as the CECP's 2020 electricity-sector greenhouse gas emission target or Clean Energy Imports strategy emission reductions—instead of being benchmarked against a particular generation technology.

In a technology-neutral LSE portfolio standard, credits would be assigned in proportion to each resource's effective emission reduction in relation to the emissions rate of a particular resource or class of resources. For example, Fore River Station 1, a natural gas combined-cycle plant with a 838 lbs/MWh emission rate, could receive 0.36, 0.56, or 0.62 credits for each MWh of generation, respectively, depending on the choice of reference resource: 1,300 lbs/MWh (an average natural gas combustion turbine); 1,900 lbs/MWh (an average oil steam turbine); or 2,200 lbs/MWh (coal steam turbine).

Alternatively, either a performance or portfolio standard could be designed to achieve a certain goal—such as the CECP's 2020 electricity-sector greenhouse gas emission target or Clean Energy Imports strategy emission reductions—instead of being benchmarked against a particular generation technology.

Synapse's qualitative analysis of CES designs identified several disadvantages of implementing an LSE performance standard in Massachusetts.

An LSE performance standard, stated in pounds emitted per MWh: 1) has not been proposed or established in any other jurisdiction, 2) comes with significant administrative and design hurdles, and 3) is not necessarily more "technology neutral" than a portfolio standard.

Based upon the analysis discussed in this report and the direction provided by MassCEC and the Agencies, Synapse focused its modeling analysis on the LSE portfolio standard design.

Based upon the analysis discussed in this report and the direction provided by MassCEC and the Agencies, Synapse focused its modeling analysis on the LSE portfolio standard design. As a helpful element of this exercise, the CES Policy Model allows for demonstration of the effect on emissions reductions and program costs of allowing particular resources—nuclear, large scale hydro, natural gas, etc.—to be excluded from or included in an otherwise technology neutral LSE portfolio standard for Massachusetts.

Our qualitative analysis also determined that REC and CEC prices would converge over time (see discussion in Section 5.5), due in part to the high demand for renewables stimulated by Massachusetts' ambitious RPS. For this reason, the LSE portfolio standard represented in the CES Policy model maintains a close relationship between REC and CEC prices, and includes the assumption that LSEs' purchase of RECs (as required by the existing Massachusetts RPS) may be used to partially satisfy CES requirements.

The model's Reference Case assumes that all CECP electricity-sector emission reduction strategies, except the Clean Energy Imports strategy and the Clean Energy Performance Standard, will be accomplished. The sole difference between the Reference and Policy Cases is the implementation of a CES. Model results depend both on the basic type of CES design chosen and on the details assumed regarding its implementation in the model. A different policy design choice or different implementation strategy might result in different costs or changes to other modeling results. So too would a different choice of emission reduction target: The policy targets explored in our analysis included GWSA electricity-sector target emissions levels (12,400 short tons (sT) in 2020 and 8,400 sT in 2030), and emission reductions equal to 0.5, 1.0, and 2.0 times the emission reductions expected from the Clean Energy Imports strategy in the CECP (5.5 million sT).

CES Policy Model results also depend on user choices. The results presented here are based on modeling "runs" using varying assumptions regarding assigning CECs to particular types of resources, requiring municipal light plants (MLPs) to comply with a CES, the share of LSEs' sales requiring CECs, the future growth of retail electricity sales, and emission reduction targets. All model runs shown here, however, use identical assumptions for all other modeling parameters including:

- CES Implementation: Policy implementation is assessed for 2020 and 2030.
- CES Design: The CES is modeled as an LSE portfolio standard.
- CES Region: The CES is implemented in Massachusetts only.
- CEC Threshold: CES credits are assigned to generators in proportion to a one ton per MWh threshold, as described below.

2.2. Key Conclusions from Report Analysis

Exploration of CES Policy Model results under various combinations of assumptions resulted in the following five findings, discussed below: (1) CES modeling is not viable for years later than 2030; (2) the share of sales requiring CECs determines the cost to ratepayers; (3) the CES does not reduce emissions if nuclear power is assigned CECs; (4) excluding MLPs from compliance raises costs; and (5) assigning CECs to natural gas raises costs.

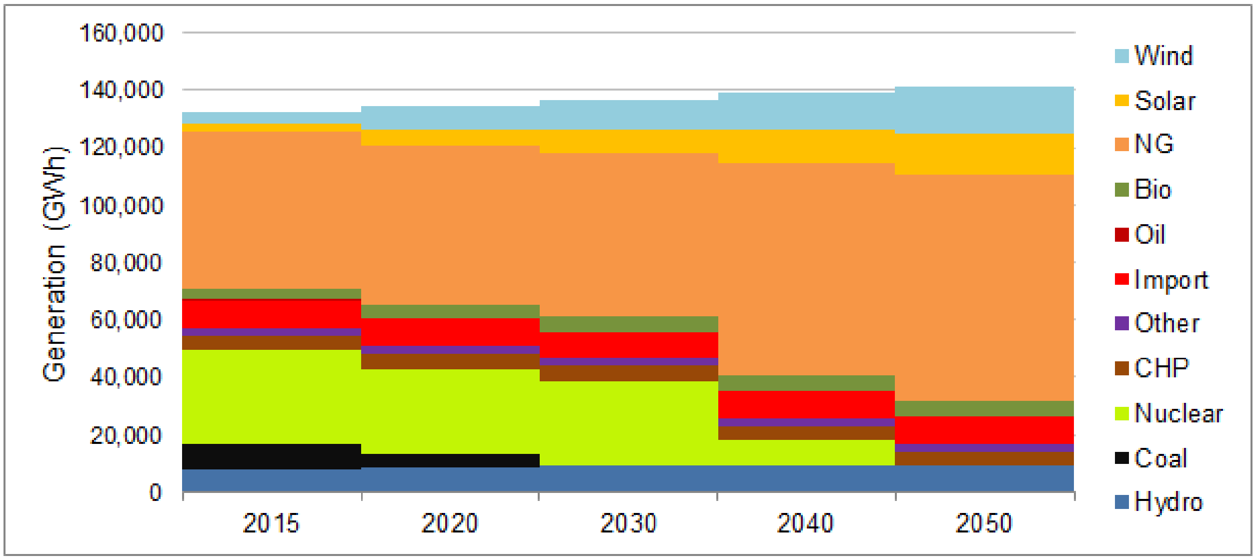
Overall, our analysis concludes that a CES designed as an LSE portfolio standard can be a viable, cost-effective option for Massachusetts as long as "windfall" CEC payments are not made to owners of resources, such as nuclear and natural gas, that will not (in the policy as modeled) contribute to new (additional) greenhouse gas emission reductions.

Our analysis concludes that a CES designed as an LSE portfolio standard can be a viable, cost-effective option for Massachusetts as long as "windfall" CEC payments are not made to owners of resources that will not contribute to new greenhouse gas emission reductions.

CES Modeling is Not Viable for Years Later than 2030

Given current plant licenses, it seems likely that by 2050 there will be no nuclear generation facilities operating in New England.[4, 5] The CES Reference case includes the assumption that New England will see 2,800 MW of nuclear retirements from 2031 to 2040, and another 1,200 MW of nuclear retirements from 2041 to 2050 (see Figure 1).

Figure 1. Reference Case Generation Mix



The loss of 22 percent of expected 2030 generation will be a massive, unprecedented planning challenge for New England. It is far more likely that the fuel mix of the resources necessary to replace nuclear generation will be determined by policy choices than by the dynamics of a potential future CES market. In the CES Policy Model, 2040 and 2050 results are swamped by the assumption that natural gas will replace exiting nuclear generation in the Reference Case. For this reason, we do not present Policy-Case modeling results for 2040 and 2050 in this report.

The loss of 22 percent of expected 2030 generation will be a massive, unprecedented planning challenge for New England.

[4] AESC 2013 makes the following assumptions regarding the retirement of New England's nuclear units: Millstone 2, 2035; Millstone 3, 2045; Pilgrim, 2032; Seabrook, 2030; and Vermont Yankee, 2032. The biennial New England Avoided Energy Supply Cost (AESC) study projects marginal energy supply costs that would be avoided due to reductions in electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England. This collaborative report includes participants from energy efficiency program administrators, utilities, regulators, and consumer and environmental advocates. See Hornby R., P. Chernick, D. White, J. Rosenkranz, R. Denhardt, E. Stanton, J. Glifford, B. Grace, M. Chang, P. Luckow, T. Vitolo, P. Knight, B. Griffiths, and B. Biewald. July 2013. Avoided Energy Supply Costs in New England: 2013 Report. Prepared by Synapse Energy Economics for the 2013 Avoided-Energy-Supply-Component (AESC) Study Group.

[5] Indeed, on August 27, 2013 Entergy announce the 2014 retirement of Vermont Yankee, although this information was released too late to be included in the modeling described in this report. Entergy Press Release, August 27, 2013, "Entergy to Close, Decommission Vermont Yankee," http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769.

The Share of Sales Requiring CECs Determines the Cost to Ratepayers

Customer utility bill increases due to CES are determined by the stringency of the requirement on LSEs—what share of load they must cover with CEC purchases, and whether or not MLPs are required to comply. The supply-side of the CES market—what resources are assigned how many credits, and what emission reductions are stimulated—has little impact on the price to consumers (with the exception of an alternative formulation of the CES policy discussed below). With the share of sales for which LSEs are required to hold CECs set to 100 percent, residential customers' bills rise with respect to the Reference Case by 9 percent in 2020 and 13 percent in 2030—regardless of the emission reductions achieved (see Table 2).

Table 2. CES Delta[6] Bill Impacts: Share of Sales Requiring CECs = 100%

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	9%	13%
Commercial	0%	9%	12%
Industrial	0%	10%	14%

As long as the share of sales for which LSEs are required to hold CECs is set to 100 percent, adjusting the CEC lbs/MWh threshold has only a small effect on emissions, and it is not possible to gradually introduce a CES policy in early years. Even with the CEC threshold set at its least stringent value (well above the emission rate of the most carbon-intensive resources in New England, e.g., at 3,000 lbs/MWh), with MLPs included and nuclear excluded (see below for more explanation of these assumptions), Massachusetts emissions fall by 12.0 million sT in 2020 and 8.3 million in 2030. In comparison, with the share of sales requiring CECs set to 100 percent and the CEC threshold set at its most stringent (at 1 lbs/MWh), Massachusetts emissions fall by 14.3 million sT in 2020 and 11.3 million in 2030. The cost to ratepayers stays the same (as shown in Table 2) regardless of CEC threshold stringency.

Choosing a constant CEC threshold and varying the share of LSEs' sales required to hold CECs allows for more flexibility in costs to rate payers and in the range of achievable emission reductions.

Instead, choosing a constant CEC threshold and varying the share of LSEs' sales required to hold CECs allows for more flexibility in costs to rate payers and in the range of achievable emission reductions. (Of course, it would also be possible to vary both the CEC threshold and the share of LSEs' sales required to hold CECs simultaneously. The number of possible combinations of assumptions is infinite, and we have not explored combined solutions in this report.) In the scenarios that follow we have set the CEC threshold to one sT of CO_2 per MWh (2,000 lbs/MWh), as shown in Table 3, with variations in the credits assigned to nuclear resources as described in the sub-sections below.

[6] "Delta" impacts are the results of the Policy Case less the results of the Reference Case.

Table 3. CEC Threshold = One Ton CO_2 per MWh (2,000 lbs/MWh)

Resource Type	Resource Emission Rate (lbs/MWh)	One Ton CO_2 per MWh (lbs/MWh)	Effective Emission Reduction (lbs/MWh)	Potential "Avoided Emission" Credits per MWh
	a	b	b - a	(b - a)/b
Nuclear	0	2,000	2,000	1.00
Hydro	0	2,000	2,000	1.00
Solar	0	2,000	2,000	1.00
Wind	0	2,000	2,000	1.00
Gas CC	1,100	2,000	900	0.45
Gas CT	1,300	2,000	700	0.35
Oil ST	1,900	2,000	100	0.05
Coal ST	2,200	2,000	-200	0.00

With MLPs included and nuclear excluded, the share of sales for which LSEs must hold CECs is 73 percent in 2020 when the 5.5 million sT target emission reduction expected from the Clean Energy Imports strategy in the CECP is achieved; the increase to residential customers' monthly bills grows by 6 percent with respect to the Reference Case in 2020. To achieve double this emission reduction (11.0 million sT), the share of sales for which LSEs must hold CECs must rise to 86 percent in 2020, while residential customers' bills grow by 8 percent with respect to the Reference Case in 2020. Extrapolating to 2030 emission levels based on the CECP 2050 Electrification Scenario, the Clean Energy Imports strategy in combination with other efforts require LSEs to hold CECs for 82 percent of sales in 2030, while the increase to residential customers' monthly bills grows by 10 percent with respect to the Reference Case.

CES Does Not Reduce Emissions If Nuclear Power is Assigned CECs

Assigning CES credit to existing nuclear generation adds 30,000 CECs to the Policy Case. Unless the CEC threshold is set low enough to exclude resources in addition to coal from receiving credits (at least as low as 1,600 lbs/MWh in 2020 and 1,500 in 2030 with MLPs complying[7]) the CES market does not bind, even with the share of LSEs' sales required to hold CECs set to 100 percent and MLPs required to comply. CES compliance can be satisfied with no change in dispatch or investment in new resources, and, therefore, no reduction in emissions (see Table 4).

The likely outcome of including nuclear generation in a CES would be windfall profits to nuclear facilities. Providing rewards to nuclear plants will not increase nuclear generation in New England .

In the scenario shown in Table 4, New England emissions are the same in the Policy Case as in the Reference Case (i.e., "delta" emissions are zero). Massachusetts emissions are more than 7 million sT lower in the Policy Case due to shuffling: Massachusetts LSEs "take credit" for all of New England's nuclear generation in this scenario; in the Reference Case, Massachusetts only takes credit for a small share of New England's

[7] 1,300 in 2020 and 1,200 in 2030 without MLPs.

nuclear generation.

Table 4. CES Delta Results: Includes Nuclear and MLPs; Threshold = 1,700 lbs/MWh; Share of Sales = 100%

Delta Emissions				
		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	0	0
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-7,472	-7,201
Massachusetts Consumption CO_2 Emissions Rate	lbs/MWh	0	-241	-227
Delta New England Costs				
		2015	2020	2030
Supply	GWh	0	0	0
Fuel Costs	M$	0	0	0
CO_2 Costs	M$	0	0	0
VOM Costs	M$	0	0	0
Variable Costs of All Resources	M$	0	0	0
Variable Costs of All Resources	$/MWh	0.0	0.0	0.0
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	52,527	48,340
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		966.5	1,367.0
Total CES Cost per MWh Sales	$/MWh		15.6	21.6
Delta Massachusetts Typical Monthly Bills (2013$)				
% change from Reference Case		2015	2020	2030
Residential		0%	9%	13%
Commercial		0%	9%	12%
Industrial		0%	10%	14%

Even though no actual emission reduction is stimulated in this scenario, residential customers see their utility bills grow by 9 percent in 2020 and 13 percent in 2030 with respect to the Reference Case. The likely outcome of including nuclear generation in a CES would be windfall profits to nuclear facilities. Providing rewards for nuclear generation will not prompt the construction of new nuclear facilities in New England (due to regulatory, cost, and political hurdles), although it may serve to prolong the life of existing facilities. The remaining scenarios shown in this report assume that existing nuclear generation will not be assigned CES credit.

Excluding MLPs from Compliance Raises Costs

Costs and emission reductions depend, in part, on whether or not MLPs are required to comply with the CES. With MLPs required to comply, in order to achieve the 5.5 million sT target emission reduction (with nuclear resources excluded from receiving CES credit and the CEC threshold set to 2,000 lbs/MWh), LSEs must hold CECs equal to 73 percent of sales in 2020 and 82 percent in 2030. The cost to residential customers would grow by 6 percent with respect to the Reference Case in 2020 and 10 percent in 2030, as shown in Table 5.

If MLPs are excluded from compliance, the cost to ratepayers would be higher to achieve the same emission reduction.

If MLPs are excluded from compliance, the cost to ratepayers would be higher to achieve the same emission reduction. The share of non-MLP sales requiring CECs would be 85 percent in 2020 and 95 percent in 2030, and residential rates would grow by 7 percent in 2020 and 11 percent in 2030 with respect to the Reference Case (see Table 6).

Table 5. CES Delta Bill Impacts: Excludes Nuclear and Includes MLPs; Threshold = 2,000 lbs/MWh

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	6%	10%
Commercial	0%	6%	9%
Industrial	0%	7%	10%

Table 6. CES Delta Bill Impacts: Excludes Nuclear and MLPs; Threshold = 2,000 lbs/MWh

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	7%	11%
Commercial	0%	7%	11%
Industrial	0%	8%	12%

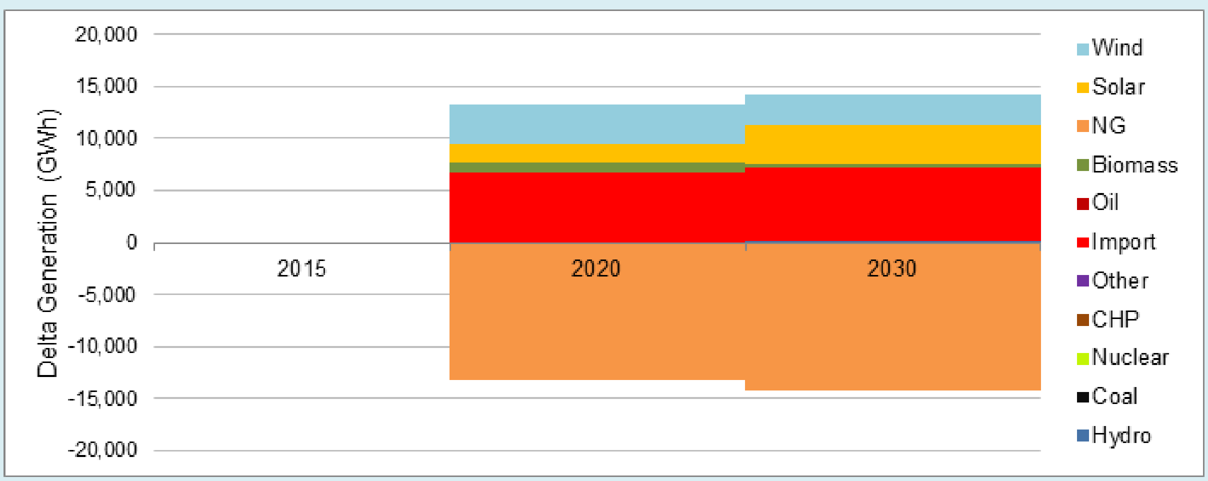
It is also the case that with MLPs excluded from compliance, higher levels of emission reductions (for example, a 11.0 million sT reduction) are simply not achievable using the CES unless both the share of sales for which LSEs are required to hold CECs and the CEC threshold are used as levers. The remaining scenarios shown in this report assume that MLPs will comply with CES.

Assigning CECs to Natural Gas Raises Costs

To achieve a 5.5 million sT target emission reduction (with nuclear excluded, MLPs required to comply, and the CEC threshold set to 2,000 lbs/MWh), LSEs must be required to hold CECs for 73 percent of their sales in 2020 and 82 percent in 2030. In this scenario (shown in detail in Table 7) residential customers' monthly utility bills rise by 6 percent with respect to the Reference Case in 2020 and 10 percent in 2030.

Table 7. CES Delta Results: Excludes Nuclear and Includes MLPs; Threshold = 2,000 lbs/MWh

Delta Emissions				
		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	-7,093	-7,635
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-5,467	-5,467
Massachusetts Consumption CO_2 Emissions Rate	lbs/MWh	0	-177	-173
Delta New England Costs				
		2015	2020	2030
Supply	GWh	0	0	0
Fuel Costs	M$	0	-166	-312
CO_2 Costs	M$	0	-75	-81
VOM Costs	M$	0	-42	-49
Variable Costs of All Resources	M$	0	-283	-441
Variable Costs of All Resources	$/MWh	0.0	-2.1	-3.2
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	35,853	36,753
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		659.7	1,039.4
Total CES Cost per MWh Sales	$/MWh		10.7	16.4
Delta Massachusetts Typical Monthly Bills (2013$)				
% change from Reference Case		2015	2020	2030
Residential		0%	6%	10%
Commercial		0%	6%	9%
Industrial		0%	7%	10%



Because the 2015 Massachusetts average emission rate (660 lbs/MWh) is lower than the average of the combined-cycle plants that represent that vast majority of natural gas resources in New England (1,080 lbs/MWh), the CES cannot achieve emission reductions by stimulating more dispatch of or new investment in natural gas resources. (In the column graph at the bottom of Table 7 above, natural gas generation—shown in orange—declines while zero-carbon generation other than nuclear grows.) In all CES policy scenarios, demand for CECs displaces natural gas and stimulates investment in new zero-carbon generation resources, including additional imports from Canada. (This simplifying assumption is discussed more fully in Section 5.5.) CEC prices paid to natural gas generators, therefore, are a windfall: these resources owners would receive payments without changing dispatch or investing in new resources.

Excluding resources with emission rates greater than the 2015 Massachusetts average from receiving CECs would have dramatic results; the effect of this exclusion, of course, is to preclude natural gas generators from receiving CECs. With the same assumptions as shown above in Table 7—nuclear excluded and MLPs required to comply—the additional exclusion of resources with emission rates greater than 660 lbs/MWh lowers both the share of sales requiring CECs and costs to ratepayers (see Table 8 below).

Excluding resources with emission rates greater than the 2015 Massachusetts average emission rate lowers both the share of sales requiring CECs and costs to ratepayers.

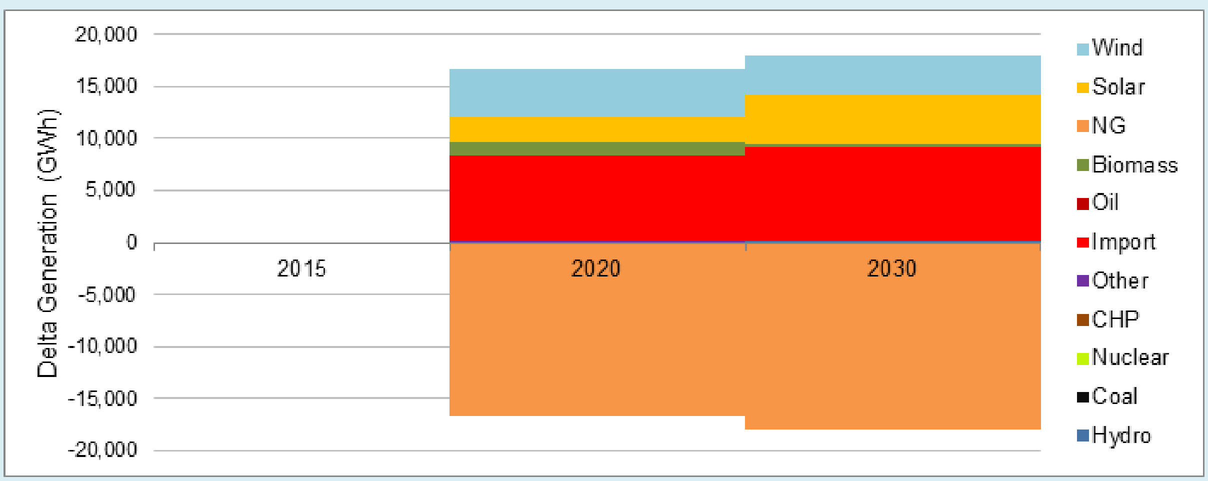
In this scenario, with natural gas resources excluded from receiving CES credit, the share of sales for which LSEs are required to hold CECs falls to 29 percent in 2020 and 39 percent in 2030. Residential customers' utility bills increase by just 2 percent with respect to the Reference Case in both 2020 and 2030, in comparison to 6 and 10 percent, respectively, with natural gas participating in the CES. Natural gas is still displaced, and emissions still fall by 5.5 million sT, but no CES payments are made to the natural gas plants that continue to operate.

Table 8. CES Delta Results: With 660 lbs/MWh Cap on Resources Receiving CECs

Delta Emissions		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	-8,941	-9,640
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-5,467	-5,467
Massachusetts Consumption CO_2 Emissions Rate	lbs/MWh	0	-177	-173

Delta New England Costs		2015	2020	2030
Supply	GWh	0	0	0
Fuel Costs	M$	0	-209	-394
CO_2 Costs	M$	0	-94	-102
VOM Costs	M$	0	-54	-62
Variable Costs of All Resources	M$	0	-357	-557
Variable Costs of All Resources	$/MWh	0.0	-2.7	-4.1
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	8,863	9,556
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		163.1	270.2
Total CES Cost per MWh Sales	$/MWh		2.6	4.3

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	2%	2%
Commercial	0%	2%	2%
Industrial	0%	2%	3%



3. CLEAN ENERGY STANDARDS IN OTHER JURISDICTIONS

Synapse's investigation of CES options for Massachusetts began with a review of similar policies in both North America and Europe. A Clean Energy Standard regulates the emission of greenhouse gases from the electricity sector. Our review of CES policies revealed a wide variety of possible regulatory mechanisms including lbs/MWh standards, share of retail sales standards, and restrictions on electricity sector contracts.

Two countries and six U.S. states have enacted CES policies with the goal of reducing or slowing the growth of CO_2 emissions from the electric power sector (see Table 9). Some of these standards apply to generators, and others apply to LSEs. The standards applied to generators typically require new or expanding plants to meet a CO_2 emission-rate performance standard, while the standards applied to LSEs typically prevent these companies from investing in, or signing long-term contracts with, plants that do not meet a CO_2 standard. Two CES policies proposed at the federal level in the United States take a different approach. These "portfolio" standards would require LSEs to cover a portion of their electricity sales portfolio with credits from specific types of power plants, deemed in the proposals to be "clean."

Table 9. Design of Clean Energy Standards in Other Jurisdictions

Federal Regulation or State	Design of Standard
Obama Clean Energy Standard Proposal	LSE-based portfolio standard
Bingaman Clean Energy Standard Act	LSE-based portfolio standard
EPA (Greenhouse Gas NSPS for Power Plants)	Power-plant-based performance standard
California (SB 1368)	LSE-based contract limitations
United Kingdom	Power-plant-based performance standard
Canada	Power-plant-based performance standard
New York	Power-plant-based performance standard
Washington (SB 6001)	LSE-based contract limitations
Oregon (ORS 469.503 & OAR 345-024-0500)	LSE-based contract limitations
Montana (HB0025)	LSE-based contract limitations
Illinois (SB 1987)	LSE-based portfolio standard

Section 3 of this report examines and compares the designs of these existing and proposed CES policies. Specifically, this section looks at:

- Several proposed federal clean energy standards, including President Obama's Clean Energy Standard Proposal, Senator Bingaman's proposed Clean Energy Standard Act of 2012, and the U.S. Environmental Protection Agency's (EPA's) New Source Performance Standards;

- Some of the best known and most established CES measures, and the interactions of these standards with emissions trading programs, including those in California and the United Kingdom; and
- Several, perhaps less familiar, proposed and existing CES measures, including those in Canada, New York, Washington State, Oregon, Montana, and Illinois.

3.1. Proposed Federal Performance Measures

President Obama's Clean Energy Standard Proposal

President Obama, in his 2011 State of the Union address, committed to adopting a federal Clean Energy Standard that would double the share of U.S. electricity generated from "clean" energy sources to 80 percent by 2035. The President's vision for a CES would support generation from a wide variety of energy sources the White House has deemed clean, including renewable energy sources (defined as wind, solar, biomass, and hydropower); nuclear power; efficient natural gas; and coal with carbon capture and sequestration (CCS).[8]

According to a report released by the White House in February 2011, the President's proposed CES would be founded on five core principles: (1) double the share of clean electricity in 25 years; (2) provide credits for a broad range of clean energy sources; (3) protect consumers against rising energy bills; (4) ensure fairness among regions; and (5) promote new technologies such as "clean coal."[9] Like the more fully developed Bingaman bill discussed below, the President's proposal envisions creating new clean energy credits for certain technologies, and requiring LSEs to cover a portion of their sales with these credits. The President's proposal would give full credits to renewable and nuclear power, and partial credits for "clean coal" and "efficient" natural gas plants. These terms are not yet defined, but may include coal facilities with CCS or coal facilities that sell the CO_2 for use in advanced oil recovery.

Senator Bingaman's Clean Energy Standard Act of 2012

In response to President Obama's 2011 State of the Union address, in March 2011, Senator Jeff Bingaman, the Chairman of the Senate Committee on Energy and Natural Resources, and Senator Lisa Murkowski, Ranking Member of the Senate Committee on Energy and Natural Resources, issued a white paper on a Clean Energy Standard. The white paper states that its purpose is to "lay out some of the key questions and potential design elements of a CES, in order to solicit input from a broad range of interested parties, to facilitate discussion, and to ascertain whether or not consensus can be achieved."[10]

---

[8] See "Innovate Our Way to a Clean Energy Future," available at: http://www.whitehouse.gov/energy/securing-american-energy.

[9] See "A Strategy for American Innovation: Securing Our Economic Growth and Prosperity," Appendix C, February 2011, available at: http://www.whitehouse.gov/sites/default/files/uploads/InnovationStrategy.pdf.

[10] Sens. Jeff Bingaman and Lisa Murkowski, Committee on Energy and Natural Resources, Untied States Senate, "White Paper on a Clean Energy Standard," March 21, 2011. Available at: http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=d9286e01-b2ea-0c97-971a-6b9d16ef32ef.

In 2012, drawing on the white paper's findings, Senator Bingaman introduced legislation that would set a national clean energy requirement of 24 percent of total electricity generation in 2015, rising by 3 percentage points per year to 84 percent in 2035.[11] The proposed Clean Energy Standard Act of 2012 (Bingaman Bill) is a portfolio standard that would require LSEs to hold clean energy credits for a certain percentage of their retail electricity sales. Generators designated as "clean" are renewables, qualified renewable biomass, hydropower, nuclear, natural gas, and qualified waste-to-energy facilities that were brought into service after 1991. New projects that employ qualified combined heat and power (CHP), have an annual carbon intensity of less than 1,640 lbs/MWh, or capture and permanently store carbon emissions are also considered "clean" under the Bingaman Bill.[12]

Resources would qualify for credits based on their carbon emissions profile compared to that of an efficient coal plant (set at 1,640 lbs/MWh of CO_2). Emissions (and therefore, credits) would be calculated on an individual power plant basis, rather than being set by category of technology, in order to encourage efficiency across all technologies. Resources with no CO_2 emissions would receive a full credit, while generators with CO_2 emissions rates above zero but less than 1,640 lbs/MWh of generation, such as combined-cycle gas turbine (CCGT) units or coal with CCS, would receive a partial credit. Plants with emissions at or above 1,640 lbs/MWh would receive no credit (see Table 10). The bill requires the Department of Energy to establish a federal clean energy credit trading program under which electric utilities submit clean energy credits to certify compliance with the clean energy requirement. Credits would be calculated based on a resource's annual sales and its annual average carbon intensity compared to the 1,640 lbs/MWh benchmark.

Table 10. Bingaman Bill Portfolio Standard Illustration

Resource Type	Resource Emission Rate (lbs/MWh)	Bingaman Standard (lbs/MWh)	Effective Emission Reduction (lbs/MWh)	Potential "Avoided Emission" Credits per MWh
	a	*b*	*b - a*	*(b - a)/b*
A	0	1,640	1,640	1.00
B	820	1,640	820	0.50
C	1,640	1,640	0	0.00
D	2,000	1,640	0	0.00

The proposed legislation would allow credits to be banked for use in future years, and starting in 2015 utilities would have the option of paying an alternative compliance payment (ACP) of $30/MWh (rising by 5 percent per year thereafter) in lieu of purchasing clean energy credits. The ACP payments would fund the State Energy

[11] S. 2146, Clean Energy Standard Act of 2012. See also, Center for Climate and Energy Solutions, "Clean Energy Standards," accessed on April 16, 2012, available at: http://www.c2es.org/federal/policy-solutions/clean-energy-standards.

[12] "Qualified CHP" is defined as: a system that uses the same source of energy to produce both electricity and thermal energy, produces at least 20 percent of the useful energy as electricity and 20 percent as thermal energy, uses only qualified renewable biomass (if biomass is used), and operates at an energy efficiency of at least 50 percent. See Clean Energy Standard Act of 2012 at Section 610(b)(3). "Qualified Renewable Biomass" is biomass produced and harvested through land management practices that maintain or restore the composition, structure, and process of ecosystems, including the diversity of plant and animal communities, water quality, and the productive capacity of soil and ecological systems. See Clean Energy Standard Act of 2012 at Section 610(b)(5).

Efficiency Funding Program, to be established not later than December 31, 2015, which would provide money to states for the implementation of state energy efficiency plans.[13]

Small utilities would be exempt from any compliance obligation.[14] Electricity sold from existing nuclear and hydropower facilities in service before 1992—nearly all U.S. plants of these types[15]—may be deducted from a utility's overall sales amount before calculating the percentage of clean energy needed for that year.[16]

Senator Bingaman requested that the Energy Information Administration (EIA) analyze the Bingaman Bill. The results of that analysis are summarized below.

- The Bingaman Bill would alter the projected generation mix as follows:
    - Coal-fired generation would decrease 25 percent with respect to the reference case level in 2025 and 54 percent in 2035;
    - Natural gas-fired generation would increase 13 percent with respect to the reference case in 2020 and 10 percent in 2035;
    - Nuclear generation would increase 16 percent with respect to the reference case in 2025 and to 62 percent in 2035; and
    - Non-hydroelectric renewable generation would increase 42 percent with respect to the reference case in 2025 and 34 percent in 2035, with wind and biomass exhibiting the largest increases.
- Annual electricity sector CO_2 emissions would decrease 20 percent with respect to the reference case in 2025 and 44 percent in 2035.
- Average electricity prices would not experience a significant impact until after 2020, as compliance with the Bingaman Bill switches from using natural gas and biomass at existing facilities to investment in new combined cycle, renewable, and nuclear capacity. Because electricity retailers with sales under a given level are exempt from the Bingaman Bill, average price impacts do not capture what may be a considerable divergence in the price impacts on customers of exempt and non-exempt electricity providers.[17]

---

[13] S. 2146, Clean Energy Standard Act of 2012 at Section 610(j).

[14] Small utilities are less than 2 million MWh of sales per year in 2015, falling by 100,000 MWh per year to 1 million MWh of sales per year in 2025. S. 2146, Clean Energy Standard Act of 2012 at Section 610(c).

[15] Only two out of 104 nuclear plants came online after 1992. See EIA, "Nuclear & Uranium," accessed on April 22, 2013, available at: http://www.eia.gov/nuclear/reactors/stats_table3.html. Of the nearly 1 GW of hydro power in the United States, about 97 percent have an in-service date prior to 1992. See, EIA, Form 860, Schedule 3, Generator, 2011, available at: http://www.eia.gov/electricity/data/eia860/.

[16] S. 2146, Clean Energy Standard Act of 2012 at Section 610(c).

[17] EIA, "Analysis of the Clean Energy Standard Act of 2012," May 2012, http://www.eia.gov/analysis/requests/bces12/pdf/cesbing.pdf

Resources for the Future[18] conducted an analysis of the Bingaman Bill, modeling how the policy might affect the electric sector under different assumptions about gas prices and anticipated environmental regulations. The key findings from that analysis are summarized below.

- The Bingaman Bill would reduce nationwide CO_2 emissions substantially—by 1.1 billion metric tons, or 41 percent of emissions with respect to the reference case, in 2035. For comparison, the United States emitted approximately 2.4 billion tons of CO_2 in 2009, of which New England's share was approximately 44 million tons.[19]
- Because of the ACP and the exemption for small utilities, the Bingaman Bill will not meet its goal of 84 percent clean energy by 2035.
- The Bingaman Bill would raise national average retail electric prices by about 18 percent by 2035.

The Union of Concerned Scientists (UCS) reviewed the Bingaman Bill and, while applauding it for setting aggressive targets, identified three major shortcomings to be addressed before the bill becomes law. First, UCS argued that mature technologies, especially natural gas-fired generation, do not need additional clean energy incentives, especially in light of concerns around hydraulic fracturing and fugitive methane emissions. Second, giving incentives to older technologies undermines the goal of a CES: to stimulate investments in new technologies and bring additional facilities online. Finally, energy efficiency should be integrated into the Bingaman Bill's provisions and, if not, then the legislation should include a stand-alone energy efficiency resource standard.[20]

Applied to Massachusetts, the Bingaman proposal would require compliance by National Grid and Northeast Utilities. All MLPs would be exempt as small utilities. Low emission sources already comprise a large share of the New England power generation mix. Assuming partial credits for gas and oil, and full credits for renewables and nuclear, the Commonwealth's "clean energy share" would be about 68 percent in 2012, far exceeding the 2015 target of 24 percent in the proposed bill.[21] This suggests that at least in the early years, the Bingaman Bill would not provide an incentive to Massachusetts generators to additionally reduce greenhouse gas emissions.

The proposed bill has not been reintroduced to the 113th Congress. It remains on the table as one possible energy policy mechanism, but no decisions have been made as to the bill's timeline or pathway forward.[22]

[18] "Analysis of the Bingaman Clean Energy Standard Proposal," available at: http://www.rff.org/News/Features/Pages/Analysis-of-the-Bingaman-Clean-Energy-Standard-Proposal.aspx.

[19] EPA, eGRID2012 Version 1.0, "Year 2009 Summary Tables," April 2012, table "Year 2009 eGRID Subregion Emissions – Greenhouse Gases."

[20] Union of Concerned Scientists, "Improvements Needed on National Clean Energy Standard," May 16, 2012, available at: http://blog.ucsusa.org/improvements-needed-on-national-clean-energy-standard.

[21] Author's calculations based on ISONE – Energy Sources in New England, http://www.iso-ne.com/nwsiss/grid_mkts/enrgy_srcs/.

[22] Personal communications with Kevin Rennert, Staff Member, State Energy and Environmental Resource Committee, April 18, 2013.

EPA Proposed Standards of Performance for Greenhouse Gases from Electric Utility Generating Units

In April 2012, under court order, the EPA proposed a draft New Source Performance Standard for greenhouse gases from new fossil-fuel electric utility generating units. The proposed requirements, which are limited to newly constructed sources and those undertaking major modifications,[23] would require fossil fuel-fired units greater than 25 MW to meet an output-based CO_2 standard of 1,000 lbs/MWh, based on the performance of widely available CCGT technology. The draft regulation includes provisions allowing new coal units to average their emissions over 30 years of operation. This means a new coal unit could delay installation of CCS for the first 10 years of its life as long as it installed CCS with 90 percent capture, which would substantially exceed the regulatory standard for the next 20 years. By the eleventh year of operation, the facility would be required to meet a CO_2 emissions level of 600 lbs/MWh on a 12-month annual average basis for the remaining 20 years. As part of the proposal, the EPA sought comment on this compliance option, and in particular on a mechanism for establishing enforceable short-term limits during the 30-year period.[24] The EPA is in the process of finalizing the standard.[25]

Once these performance standards for new units are finalized, the Clean Air Act also requires EPA to establish a minimum threshold for states to use in the development of emission performance standards for greenhouse gases from existing power plants. Each state will have to submit a plan to EPA (similar to a State Implementation Plan for criteria air pollutants) that lays out how the performance standards for existing sources will be implemented.[26] The promulgation of performance standards for existing power plants is a highly contentious subject. In a June 25, 2013 memorandum,[27] President Obama, as part of his Climate Action Plan, directed EPA to propose standards for existing plants by June 1, 2014 and finalize them by June 1, 2015.

3.2. CESs in Other Jurisdictions

California

In 2005, California Governor Arnold Schwarzenegger issued an Executive Order calling for a reduction in California's emission of greenhouse gases to 1990 levels by 2020. In September 2006, California adopted Senate Bill 1368, called the Emission Performance Standards (EPS).[28] The legislature determined that "in order to have any meaningful impact on climate change, the Governor's goals for reducing emissions of greenhouse

---

[23] As of April 13, 2012.

[24] EPA, Proposed Rule Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, April 13, 2012, I.B.5.a.ii, III.B.2; available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-0001.

[25] See http://www.epa.gov/airquality/cps/settlement.html.

[26] 42 U.S.C. §7411(d).

[27] http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards

[28] Perata, Chapter 598, California Statutes of 2006.

gases must be applied to the state's electricity consumption, not just the state's electricity production."[29] The law requires the California Energy Commission and the California Public Utilities Commission (CA PUC) to adopt regulations that establish an emission performance standard for greenhouse gases for all baseload generation (defined as a 60 percent or higher capacity factor) of local, publicly owned electric utilities and load-serving entities "at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation."[30]

The California Energy Commission established regulations that preclude LSEs and publicly owned utilities from investing in or signing long-term contracts with baseload plants with CO_2 rates in excess of 1,100 lbs/MWh.[31] While the standard applies to all baseload generation facilities, public utilities are only required to report procurements involving baseload generation of 10 MW or greater. The standard is limited to CO_2 emissions because, according to the statute: "[T]his pollutant makes up the overwhelming majority of greenhouse gas emissions and is the most reliable and efficient measure of greenhouse gas performance."[32] The regulations do not allow averaging emissions across commonly owned units; rather, each baseload generator must comply with the standard on its own.

The 1,100 lbs/MWh standard was established after evaluation of the performance of existing CCGT baseload power plants in the West, with special consideration given to existing California plants. This relatively high (weak) lbs/MWh standard (reflecting the performance capabilities of older, existing CCGTs as opposed to new CCGTs) was established because, as the Energy Commission explained, it did not want to disadvantage new, clean units locating in adverse conditions such as high altitude or hot temperatures. The law also allowed for all CCGTs that were in operation or had a final permit to operate as of June 30, 2007 to be deemed in compliance. Any generating units added to these existing "deemed compliant" plants are required to meet the standards if the combined units increase the plant's generating capacity by 50 MW or more.[33] Because the standard applies to utilities' investments in and LSEs' procurements of baseload generation, it does not matter whether that generation is located in state or out of state.

The CA PUC established procedures for determining and verifying the emissions of CO_2 from baseload generation subject to the emissions performance standard. California's procedure for determining generators' emissions is based on capacity factors, heat rates, and corresponding emissions rates that reflect the expected operations of power plants and not their full load heat rates.[34] Within ten business days after entering into a contract, local publicly owned electric utilities must submit a compliance filing to the CA PUC that provides

---

[29] Id. at Sec. 8340(k).

[30] Id. at Sec. 8341(d)(1) and 8341(e)(1). In California, the Energy Commission is responsible for certifying renewable resources, verifying compliance with RPS requirements, and controlling greenhouse gases. The CA PUC regulates public utilities and is required to review and approve a procurement plan and a renewable energy procurement plan for each of the state's public utilities.

[31] Long-term is defined as greater than 5 years.

[32] Id. at 3.

[33] 20 CCR 11 §2901(e).

[34] 20 CCR 11 § 2903(a).

documentation of the contract, including whether the contract is new or renewed, is with a generation source that uses CCS, and whether the contract is based on unspecified energy purchases (see below for more information on unspecified energy purchases). The CA PUC then reviews the compliance filing for completeness and compliance with the regulations.[35]

The California EPS is currently being evaluated in response to environmental organizations' concerns that investments in non-EPS compliant facilities are not being reviewed by the Energy Commission and that California's utilities may be continuing to make substantial investments in existing coal plants.[36] The groups have requested that California's Energy Commission amend the implementing regulations to require review of all procurements made by the utilities. At the same time, the utilities have requested a full re-evaluation of the CA PUC's and the Energy Commission's regulations implementing the EPS, as required by Public Utilities Code §8341(f).[37] To our knowledge, data regarding actual greenhouse gas emission reductions from the California EPS are not yet available.

In addition, Assembly Bill 32 (AB 32) requires the California Air Resources Board (ARB) to develop a Scoping Plan that describes the approach California will take to achieve the goal of reducing emissions to 1990 levels by 2020.[38] The Scoping Plan—first approved in 2008, and scheduled for updating in 2013—recommended that the state expand its energy efficiency and RPS programs, develop a cap-and-trade program, establish targets for transportation-related greenhouse gases emissions, and implement other policies intended to reduce statewide greenhouse gas emissions.[39]

In response to AB 32 and the Scoping Plan, in 2011 the ARB adopted a cap-and-trade regulation that sets a statewide limit on sources responsible for 85 percent of California's greenhouse gas emissions. The major emission sources that the cap-and-trade program covers are refineries, power plants, industrial facilities, and transportation fuels. The emission cap is set in 2013, at about 2 percent below emissions forecasted for 2012, and declines 2 percent in 2014 and 3 percent annually from 2015 through 2020.[40]

---

[35] 20 CCR 11 §§ 2909, 2910.

[36] See "Joint Petition of the Natural Resources Defense Council and the Sierra Club for Initiation of a Rulemaking Regarding California's Emissions Performance Standard," November 14, 2011, available at : http://www.energy.ca.gov/emission_standards/2012rulemaking/documents/joint-petiton/2011-11-14_SB1368_Petition.pdf.

[37] See California Energy Commission "Order Instituting Rulemaking to Consider Modification of Regulations Establishing a Greenhouse Gases Emissions Performance Standard for Baseload Generation of Local Publicly Owned Electric Utilities," Order 12-0112-7, January 12, 2012.

[38] For more information, see California Air Resource Board, "Assembly Bill 32: Global Warming Solutions Act," accessed on April 18, 2013, available at: http://www.arb.ca.gov/cc/ab32/ab32.htm. The Scoping Plan was first approved by the ARB in 2008 and will be updated in 2013 to evaluate the mix of AB 32 policies to ensure that California is on track to achieving the 2020 greenhouse gas reduction goal. For more information, see California Air Resource Board, "AB 32 Scoping Plan," accessed on April 18, 2013, available at: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm

[39] ARB, Climate Change Scoping Plan, December 2008, ES-3.

[40] ARB, "Overview of ARB Emissions Trading Program," October 20, 2011.

Several of the measures recommended in the Scoping Plan are intentionally designed to complement one another. For example, the cap-and-trade program creates an emissions cap on the sectors responsible for the vast majority of California's greenhouse gas emissions and provides the capped sources significant flexibility in how they collectively achieve the reductions necessary to meet the cap.[41] California's cap-and-trade regulation is projected to account for less than 20 percent of the total emissions reductions required under the Scoping Plan. The cap under ARB's rule is flexible and can be tightened if ARB's other emission reduction measures are less effective than anticipated. Should the other Scoping Plan measures covering capped sectors underperform, the cap is the backstop to ensure California will comply with AB 32.[42]

While the Scoping Plan acknowledges that the EPS is part of California's climate change policy, it does not identify the EPS as a specific emissions reduction measure that the capped sectors can use to complement the cap-and-trade program. California's cap-and-trade program, however, recognizes the EPS through its regulations on leakage and resource shuffling.[43] The cap-and-trade program attempts to regulate leakage by placing compliance obligations on electricity imported into the state as well as electricity generated in the state, although these regulations were put on abeyance by the California Air Resources Board at the request of the Federal Energy Regulatory Commissions (FERC) in August 2012.[44]

California uses the First Jurisdictional Deliverer approach to regulate imports, which assigns responsibility for emissions arising from imported electricity to those entities that first import power into the regulated region. To monitor and track emissions from imported electricity, California created a distinction between specified and unspecified transactions of electricity. Specified transactions are agreements between out-of-state generators and in-state LSEs where the generating plant is known, and it is therefore relatively easier to assign emissions to the electricity being imported. Unspecified transactions refer to imported electricity where it is unclear specifically where the power originated. California makes certain modeling assumptions about generation and related emissions in neighboring power systems and develops a "default emissions rate" that it attributes to unspecified load. Under California's default assumptions, all unspecified imports are assigned a regional default emission factor of 1,100 lbs of CO_2/MWh produced, regardless of the geographic region from which the electricity is imported.[45]

---

[41] ARB, Climate Change Scoping Plan, December 2008, 28.

[42] Natural Resources Defense Council, "10 Questions about California's Cap and Trade Program," accessed on April 18, 2013, available at: http://switchboard.nrdc.org/blogs/kgrenfell/10_questions_about_californias.html; C2ES, "California Cap and Trade," accessed on April 18, 2013, available at: http://www.c2es.org/us-states-regions/key-legislation/california-cap-trade#Overall.

[43] Leakage is defined in California as a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state. California Health and Safety Code § 38505. Resource Shuffling is a form of leakage that could occur in the electricity sector. Resource shuffling is defined in California as any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid. 17 CCR 11 § 95802(a)(250). See ARB, "Cap-and-Trade Regulation Instructional Guidance," Appendix A, November 2012, available at: http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf

[44] Letter to Governor Brown from FERC Commissioner Moeller, August 6, 2012, http://www.ferc.gov/about/com-mem/moeller/moeller-08-06-12.pdf

[45] Columbia Law School, "Legal Issues in Regulating Imports in State and Regional Cap and Trade Programs," October 2012, 10-13.

The ARB specifically identifies resource shuffling as replacing relatively lower emission electricity with electricity generated at a high-emission, out-of-state power plant procured by an LSE under a long-term contract or ownership arrangement, when the power plant does not meet California's EPS, and the substitution is made in order to reduce an LSE's compliance obligation under the cap-and-trade program. Similarly, ARB specifies that resource shuffling also occurs if an LSE assigns such a long-term contract for high-emission electricity to a third party for the purpose of reducing a compliance obligation under the cap-and-trade program.[46]

California's import regulations have not yet faced a legal challenge, but many anticipate that as the program moves from planning to implementation, challenges will develop. The two legal issues that are generally thought to be the most likely arguments raised against import regulations are whether they violate the Commerce Clause of the Constitution, and whether such regulations are preempted by the Federal Power Act. The Commerce Clause has been interpreted as limiting states' ability to impose burdens on interstate commerce. According to a Columbia Law School report, any legal challenges made by aggrieved parties based on the Commerce Clause would likely prove unsuccessful in court. A court would probably not find import regulations unconstitutional because resource shuffling regulations (via application of a system-based emissions factor and limitations on specified contracts) would not involve any transactions occurring entirely out-of-state. The Columbia Law School report likewise states that a court would find that these regulations do not discriminate against out-of-state commerce, as they impose a cost on First Jurisdictional Deliverers or LSEs who import electricity that is comparable to the cost already imposed on in-state generators subject to the cap and trade system.[47]

Regarding Federal Power Act legal concerns, the doctrine of preemption is derived from the Supremacy Clause of the Constitution, which makes federal law the supreme law of the land and thus implies that state laws that contradict federal law cannot stand. The Columbia Law School report also finds that import regulations would likely withstand an Federal Power Act preemption challenge, because there is not a strong argument to be made that import regulations interfere with FERC's jurisdiction over interstate transmission or the wholesale electricity market in such a way that the preemption doctrine could apply.

United Kingdom

The United Kingdom has also committed to decarbonization of its economy and has established a goal of reducing the country's total greenhouse gas emissions to 80 percent of its 1990 levels by 2050.[48] The two-party Coalition's *Programme for Government* made a policy commitment to establish a standard that would "prevent coal-fired power stations from being built unless they are equipped with sufficient carbon capture

[46] ARB, "Cap-and-Trade Regulation Instructional Guidance," Appendix A, November 2012, available at: http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf.

[47] Columbia Law School, "Legal Issues in Regulating Imports in State and Regional Cap and Trade Programs," October 2012, 9, 17-18, 23-25.

[48] See Climate Change Act 2008, available at: http://www.legislation.gov.uk/ukpga/2008/27/contents.

and storage to meet the emissions performance standard."[49] In May 2012, the *Programme* introduced the draft Energy Bill 2012-13, which sets a statutory limit on the amount of annual CO_2 emissions permitted from new fossil fuel generators. At present, the Carbon Dioxide Emissions Performance Standard (UK EPS) is proposed at 450 kg/MWh, or 992 lbs/MWh, and would be used to calculate the per unit annual CO_2 emission limit for plants operating at baseload (defined as an 85 percent or higher capacity factor).[50] This same annual limit is expected to be "grandfathered" for each new plant until 2045. The locking-in of the standard for the economic life of the plant was determined to be necessary in order to provide certainty for developers and investors planning new projects.[51]

The proposed UK EPS level was determined based on the average emissions intensity of the country's power plants in 2010. It would apply to all fossil-fuel fired power plants that are larger than 50 MW, including new plants and existing plants that undergo significant life extensions (though not including CCS retrofits, projects installed in compliance with European environmental standards,[52] or projects that help increase the use of biomass) starting in 2014. The law exempts coal plants that are part of the United Kingdom's CCS Commercialisation Programme and those that benefit from European Union funding for commercial-scale CCS demonstration.

The regulations implementing the proposed UK EPS have not yet been worked out and are expected to be established with secondary legislation. New monitoring and enforcement regulations are expected to utilize the emissions reporting requirements from the European Union Emissions Trading Scheme (EU ETS) to help determine compliance with the EPS. Of particular interest will be how the government will handle the timeframe for the grandfathering provision, and how the UK EPS will be constructed so as not to disadvantage CHP projects, which are seen as pivotal for helping to meet the electric industry's decarbonization goals, since CHP would displace the need for carbon-producing heat generation, particularly in the industrial sector.[53]

While the Draft Energy Bill containing the EPS has not yet been finalized, at the end of January 2013 a member of the United Kingdom's Labour Party introduced an amendment to the bill that would drastically reduce (make more stringent) the proposed EPS from 450 kg/MWh to 200 kg/MWh beginning in 2020. The

---

[49] See Energy Bill 2012 summary from Department of Energy and Climate Change: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/68778/Energy_Bill_-_Emissions_Performance_Standard.pdf.

[50] See "EPS Impact Assessment, Part 2," available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48137/2179-eps-impact-assessment-emr-wp.pdf.

[51] Id.

[52] Specifically, upgrades required to meet the Integrated Emissions Directive, which related to minimizing pollution from various industrial sources throughout the European Union. European Commission, "The Industrial Emission Directive," accessed on April 22, 2013, available at: http://ec.europa.eu/environment/air/pollutants/stationary/ied/legislation.htm. See "EPS Impact Assessment, Part 1," p 12, available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66042/7061-emissions-performance-standard-impact-assessments.pdf.

[53] See "Electricity Market Reform: Update on the Emissions Performance Standard," available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48375/5350-emr-annex-d--update-on-the-emissions-performance-s.pdf.

amendment also would shorten the proposed grandfathering period from ending in 2045 to ending in 2029.[54] Though unlikely to gain support, this amendment would have the effect of requiring CCS for both coal and gas plants beginning in 2020.

If an EPS is passed in the UK, it is uncertain how it would interact with the EU ETS.[55] A UK EPS would overlap with the EU ETS because the power sector is a capped industry within the EU ETS. While a UK EPS could result in the UK power sector reducing its carbon emissions at a faster rate than would otherwise occur under the EU ETS, any increased emission abatement in the UK from an EPS potentially could be offset by less abatement by other countries participating in the EU ETS. Therefore, a UK EPS would not necessarily lead to any overall emissions reductions at the global level. The UK EPS could also drive down the price of EU ETS allowances because more allowances would be made available through UK abatement efforts, and a lower allowance price could reduce the economic incentive for investment in abatement efforts elsewhere in Europe.[56]

In the long run, the EU ETS cap could be tightened to account for the UK EPS, which would then likely bring about actual emissions reductions. In 2010, the UK House of Commons made similar conclusions, stating that "it would not be sensible to introduce an EPS if its sole aim is to drive immediate emissions reductions from the power sector since the EU ETS already exists to do this. However, we also note that the EU ETS cap needs to be significantly tighter than its current and planned future level if it is to be effective in achieving reductions."[57] Legal considerations would need to be investigated as to whether such an action could be implemented by the EU ETS participating countries. A report from University College London notes, however, that a UK EPS could drive technological innovation in emissions abatement, which is likely to encourage a tightening of overall caps for the EU ETS in the long-term.[58]

Another study found that the least-cost way to reduce power-related carbon emissions in Europe would be to supplement the EU ETS with emission performance standards for energy. Emission performance standards can quicken the pace of investment in abatement technology if the EU ETS cannot deliver the correct price signals

---

[54] See "Gardiner Amendments to Energy Bill," January 29, 2013, available at: http://www.publications.parliament.uk/pa/bills/cbill/2012-2013/0100/amend/pbc1002901m.pdf.

[55] The EU ETS covers more than 11,000 power stations and industrial plans in 31 countries, as well as airlines. The EU ETS covers emissions of CO_2 from power plants, a wide range of energy-intensive industry sectors and commercial airlines. Nitrous oxide emissions from the production of certain acids and emissions of perfluorocarbons from aluminum production are also included. In total, about 45 percent of total European greenhouse gas emissions are limited by the EU ETS. Annually, a company must surrender enough allowances to cover all its emissions, otherwise heavy fines are imposed. If a company reduces its emissions, it can keep the spare allowances to cover its future needs or else sell them to another company that is short of allowances. European Commission, "The EU Emissions Trading System (EU ETS)," accessed April 22, 2013, available at: http://ec.europa.eu/clima/policies/ets/index_en.htm.

[56] UK Parliament, "The Role for an Emissions Performance Standard," prepared December 2, 2010, accessed April 22, 2013, available at: http://www.publications.parliament.uk/pa/cm201011/cmselect/cmenergy/523/52306.htm. See also, University College London, "CO_2 Emission Performance Standards: A Submission to the UK Select Committee on Energy and Climate Change," October 2010, available at: http://blogs.ucl.ac.uk/law-environment/files/2012/12/Think-piece-3-Macrory.pdf.

[57] UK Parliament, "The Role for an Emissions Performance Standard," prepared December 2, 2010, accessed April 22, 2013, available at: http://www.publications.parliament.uk/pa/cm201011/cmselect/cmenergy/523/52306.htm

[58] University College London, "CO_2 Emission Performance Standards: A Submission to the UK Select Committee on Energy and Climate Change," October 2010, available at: http://blogs.ucl.ac.uk/law-environment/files/2012/12/Think-piece-3-Macrory.pdf.

on the schedule required by policy-makers, or provide the consistency required by industry for long-term, large-scale investment.[59]

Canada

Canada has a greenhouse gas reduction goal of 17 percent below 2005 levels by 2020. In September 2012, Canada finalized a national environmental performance standard for coal. The law requires new coal-fired units that start operation after June 30, 2015, and existing coal-fired units that are 50 years old or older,[60] to meet a CO_2 emission performance standard of 420 kg/MWh, or 926 lbs/MWh. This standard is based on the emissions performance of a new CCGT unit.[61]

New York

The State of New York, which has a number of aggressive greenhouse gas reduction policies, recently adopted performance standards for emissions from electric generating facilities with a nameplate capacity of 25 MW or greater.[62] The standards vary according to technology. CCGTs, gas-fired stationary internal combustion engines, and other types of facilities firing at least 70 percent fossil fuels, are subject to a CO_2 limit of either 925 lbs/MWh gross electrical output (output-based limit) or 120 lbs/MMBtu (input-based limit).[63] Facilities firing liquid fuels or a mix of liquid and gaseous fuels must comply with a standard of either 1,450 lbs/MWh (output-based limit) or 160 lbs/MMBtu (input-based limit). The standards apply to any entity that proposes to construct a new major electric generating facility or to expand an existing electric generating facility by increasing its electrical output capacity by at least 25 MW.

Washington

Washington State's emission performance standard is almost identical to California's EPS. The CO_2 performance standard is the lower of: (a) 1,100 lbs/MWh, or (b) the average available greenhouse gas emissions output of CCGTs, as determined and updated by the Washington Department of Commerce (DOC).

---

59 University College London, "CO_2 Emission Performance Standards: A Submission to the UK Select Committee on Energy and Climate Change," October 2010, available at: http://blogs.ucl.ac.uk/law-environment/files/2012/12/Think-piece-3-Macrory.pdf. Science Daily, "Power Emissions Limits to Save Most Carbon at Least Cost, Study Suggests," January 21, 2009, available at: http://www.sciencedaily.com/releases/2009/01/090120171459.htm

60 The Canadian standard also has special provisions for existing units that were commissioned during the years 1970 to 1974, which are subject to the performance standard at the end of 2019, and units commissioned during the years 1980–1985, which are subject to the performance standard at the end of 2029.

61 See "Harper Government Moves Forward on Tough Rules for Coal-Fired Electricity Sector," September 5, 2012, available at: http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=4D34AE9B-1768-415D-A546-8CCF09010A23. See also, Government of Canada, Canada Gazette, "Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations," August 30, 2012, accessed April 22, 2013, available at: http://www.gazette.gc.ca/rp-pr/p2/2012/2012-09-12/html/sor-dors167-eng.html.

62 See 6 NYCRR Part 251.

63 Output-based limits refer to a measure of the emissions per unit of energy output (lbs/MWh), while input-based limits refer to the emissions per unit of fuel energy input (lbs/MMBtu).

The DOC is required to survey new, commercially available CCGTs every five years and adjust the "average available" greenhouse gas emissions output based on its findings.[64] The standard applies to new in-state baseload generation, new long-term contracts, and existing coal-fired generation facilities after 2020. Both investor-owned utilities and customer-owned utilities must comply with the regulation.[65]

The Washington performance standard also allows utilities to submit plans for compliance through the permanent sequestration of carbon through CCS technology. These plans must demonstrate financial, technical, and economic feasibility; the sequestration must begin within five years of plant operation; and penalty provisions apply should the plan fail to achieve adequate CO_2 reductions on schedule.[66]

Oregon

Oregon's SB 101 was also modeled after California's EPS and precludes LSEs, publicly owned utilities, and consumer-owned utilities from investing in or signing long-term contracts with baseload generating facilities with CO_2 emissions at or greater than 1,100 lbs/MWh. This requirement applies to long-term contracts with generation units that are either in-state or out-of-state.[67] Notably, Oregon's law explicitly excludes life-cycle emissions of the fuel from the determination of a facility's total emissions.[68]

Montana

Under a 2007 Montana law, utilities may not acquire an equity interest in or lease a facility or equipment used to generate electricity that is primarily fueled by coal and that is constructed after January 1, 2007 unless a minimum of 50 percent of the CO_2 is captured and stored. The law effectively only applies to one utility in Montana—Northwest Energy—and it applies only when the utility is seeking approval of a resource that it has not previously contracted with or held an equity interest in. The law's effectiveness is limited since it does not cover rural electric cooperatives, which serve about a third of the state's electric demand.[69]

Illinois

Illinois adopted SB 1987 in 2009, establishing a Clean Coal Portfolio Standard. The law requires each utility to serve at least 5 percent of its total supply with "initial clean coal facilities" by 2015, and has a goal of meeting 25 percent of the state's demand for electricity with "clean coal" facilities. Under SB 1987, "clean coal" is

[64] See Washington S.B. 6001; see also "Regulatory Assistance Project Research Brief: Emissions Performance Standards in Selected States," at 3, November 2009.

[65] RCW 80.80.040, Greenhouse Gas Emissions Performance Standards – Rules – Sequestration, available at: http://apps.leg.wa.gov/RCW/default.aspx?cite=80.80.040.

[66] SB 6001, Section 5, Subsections (11)-(13).

[67] OAR 860.085.

[68] See Oregon S.B. 101; see also "Regulatory Assistance Project Research Brief: Emissions Performance Standards in Selected States," at 5, November 2009.

[69] See Montana H.B. 25; see also "Regulatory Assistance Project Research Brief: Emissions Performance Standards in Selected States," at 4, November 2009.

defined by the level of CO_2 reduction achieved through CCS. The law requires 50 percent capture for facilities beginning operation before 2016, 70 percent capture for facilities beginning operation in 2016 or 2017, and 90 percent capture for facilities coming online after 2017.[70]

3.3. Key Features of CESs in Other Jurisdictions

The existing and proposed CESs reviewed in this report fall into three categories of policy design:

1) **Performance standards applied to power plants** (*U.S. EPA Greenhouse Gas NSPS for Power Plants, United Kingdom, Canada, New York*). These standards generally affect new or expanded plants or (in one case) very old plants. Because these standards are applied to generators, there is no need for a system that tracks generation to LSEs. There is also no risk of shuffling.

2) **Standards applied to LSEs that prohibit them from investing in, or signing long-term contracts with, CO_2 intensive sources** *(California, Washington, Oregon, Montana).*[71] These standards seek to reduce demand for electricity from CO_2 intensive plants. If they succeed in doing so, they may also provide benefits to existing or new "clean" plants, but the primary policy goal is to put pressure on high-emitting plants. These standards are implemented through review of, or mandatory reporting of, an LSE's equity holdings and long-term contracts. There is no need to track all electricity in the region to an LSE.[72] There is some risk of "contract shuffling" in this type of policy, where LSEs switch from long-term contracts to transactions in the spot market (or below year-limit contracts) to avoid regulation and emissions reductions do not occur. Standards applied to LSE investments or long-term contracts in power plants are only applicable to vertically integrated utilities. In restructured states, like Massachusetts, LSEs do not own generation and generally do not enter into long-term contracts with specific generators. In Massachusetts, the investor-owned utilities procure electricity for basic service customers from wholesale suppliers for periods of three months to one year, with the primary exception of legislatively mandated long-term contracts for renewable energy.

3) **Standards applied to LSEs that require them to cover some portion of their sales portfolio with credits from specific resources** *(Bingaman Clean Energy Standard Act, Obama Clean Energy Standard Proposal).* These proposals would require a new system of tradable credits. Eligible plants would generate a credit with each MWh produced. (Some technologies may generate a partial credit with each MWh.) As with their RPS compliance, LSEs would be

---

70 See SB 1987, available at: http://www.ilga.gov/legislation/publicacts/95/PDF/095-1027.pdf.

71 The Illinois standard is a variation on this category. It requires LSEs to invest in clean coal.

72 A standard that is implemented through contracts that require an action are typically easier to monitor and enforce because the regulatory body only needs to review the contracts that contain the required actions. Conversely, contracts that restrict a certain action can be more difficult to monitor because the regulatory body would need to review every contract to ensure that the restricted action is not being taken.

required to hold credits covering a defined percentage of their total sales. Applied at the national level, shuffling would be avoided if the policy covered all (or nearly all) power plants and LSEs throughout the country. Shuffling could be avoided at the state level if, during policy design, regulators were cognizant of total expected supply of and demand for credits, setting the portfolio percentage requirement to ensure that the standard resulted in altered plant build or retirement decisions, and/or altered dispatch of existing plants.

In addition to these three policy design categories, it is worth noting that, to our knowledge, no jurisdiction has adopted a CES in which: LSEs are required to hold a credit for every MWh sold; each eligible plant produces credits with a unique CO_2 emission rate; or the pool of credits is much larger than demand for the credits. In New England, NEPOOL GIS creates certificates for every MWh generated and sold that include emission information from the plant that generated the MWh; however, GIS does not enforce regulations or track the exact emissions from each specific generating unit to a particular LSE.

A final key point taken from our analysis of other jurisdictions is that in cases where a jurisdiction has an existing or proposed CES in addition to participating in a cap-and-trade program—California and the United Kingdom—the expectation of analysts and policy makers is that the CES will act as one of several measures to achieve emission reductions under the cap, and that the emission cap will be lowered in future years in response to the CES and other successful mitigation programs.

Table 11, below, summarizes the key policy design characteristics of the CES policies reviewed in this section and identifies whether the proposed federal regulation or state policy is technology neutral. For this purpose, a CES policy is technology neutral if all electricity generating technologies are allowed to participate, and their participation is managed by a technology independent criterion such as carbon intensity, as opposed to a CES policy that does not allow certain technologies to participate. It is important to note that both "lbs/MWh performance standards" and "share-of-retail-sales portfolio standards" have the potential to be either technology neutral or technology specific depending on their design.

Table 11. Main Characteristics of Existing Emission Performance Standards (table continues on following two pages)

Federal Regulation or State	Applicability	Technology Neutral?	Form of Standard	Pollutants Covered	Plants or LSEs	Tracking System
Obama Clean Energy Standard Proposal	Utility portfolios	No - credits given to sources based on the source's specific technology	Requirement for an increasing percentage of electricity sold to be "clean"	CO_2	LSEs	Tradable credits
Bingaman Clean Energy Standard Act	Utility portfolios	Yes - credits calculated by plant emission rate (annual sales greater than 2 million MWh), not set by category of technology	Requirement for an increasing percentage of electricity sold to be "clean" as defined, starting at 24% in 2015, rising to 84% by 2035	CO_2	LSEs	Tradable credits
U.S. EPA (Greenhouse Gas NSPS for Power Plants)	New (post April 13, 2012) fossil-fueled electric generating units	No - applies only to fossil fuel-fired units greater than 25 MW	1,000 lbs CO_2/MWh	CO_2	Plants (new)	Emissions would be reported through EPA's data systems
California (SB 1368)	New and existing baseload generation owned or under long-term contract to publicly owned utilities; all existing CCGTs are deemed compliant until significant upgrades (increase capacity by 10MW)	Yes - applies to each baseload generator with a capacity factor 60% or higher	Emission rate of 1,100 lbs CO_2 per MWh; based on performance of existing CA CCGTs	CO_2	LSEs	Reporting of investments and long-term contracts subject to EPS
United Kingdom	New fossil-fueled generation of 50MW or more; plants in CCS program are exempt	No - applies only to fossil fuel-fired units greater than 50 MW	Emission rate of 450 g CO_2/kWh or 992 lbs CO_2/MWh; based on performance of a new CCGT	CO_2	Plants (new)	To be based on the EU Emissions Trading System (ETS)
Canada	New coal generation and existing coal plants 50 years old or older	No - applies only to coal-fired generation	Emission rate of 926 lbs CO_2/MWh; based on performance on a new CCGT	CO_2	Plants (new and very old)	Annual performance report submitted through electronic data system

Federal Regulation or State	Applicability	Technology Neutral?	Form of Standard	Pollutants Covered	Plants or LSEs	Tracking System
New York	Any entity seeking to construct a new major electric generating facility or modify an existing facility so as to increase the capacity by at least 25 MW	No - applies only to fossil fuel facilities (firing liquid fuels or a mix of liquid and gaseous fuels)	Boilers that fire at least 70% fossil fuels, CCGTs, and stationary internal combustion engines must meet a limit of either 925 lbs/MWh or 120 lbs/MMBtu; simple cycle combustion turbines and stationary internal combustion engines that fire either liquid fuel or liquid and gaseous fuel simultaneously must meet a CO_2 emission limit of either 1450 lbs/MWh or 160 lbs/MMBtu; other types of generators, like biomass and waste-to-energy facilities, are required to propose a case-specific CO_2 limit	CO_2	Plants (new or expanded)	Emissions reporting similar to reporting on other pollutants
Washington (SB 6001)	New and existing baseload generation owned or under long-term contract to publicly owned utilities; existing cogeneration facilities fueled by natural gas or waste gas are exempt until upgraded or subject to new ownership interest	Yes - applies to all baseload generation in operation after June 30, 2008	The lower of: (1) 1,100 lbs CO_2 per MWh or (2) the average emission rate of new, commercially available CCGTs, as determined by the state every five years (starting in 2013)	CO_2	LSEs	Reporting of investments and long-term contracts
Oregon (ORS 469.503 & OAR 345-024-0500)	New and existing baseload generation owned or under long-term contract to publicly owned utilities; sources that use natural gas or petroleum distillates for peaking or to integrate energy from renewable energy sources are exempt; renewables are exempt (renewable does not include biomass)	Yes - applies to all generation facilities	Emission rate of 1,100 lbs CO_2 per MWh; calculation of emission explicitly excludes life cycle emissions for obtaining the fuel used at the facility	CO_2	LSEs	Reporting of investments and long-term contracts
Montana (HB0025)	New (post January 1, 2007) coal facilities in which formerly restructured Montana utilities are	No - applies only to coal facilities constructed after	Any new contract or equity interest in coal generating facilities by a formerly restructured utility is	CO_2	LSEs	Reporting of investments and contracts

Federal Regulation or State	Applicability	Technology Neutral?	Form of Standard	Pollutants Covered	Plants or LSEs	Tracking System
	seeking a new equity interest or contract	January 1, 2007	prohibited unless the facility uses CCS to capture and sequester at least 50% of CO_2 emissions			with procurement plans
Illinois (SB 1987)	Illinois utilities' energy supply portfolios	No - applies only to coal facilities using CCS	Requires utilities to serve at least 5% of their load with "clean coal" beginning in 2015 and increasing to 25% by 2025; "clean coal" is defined as: a facility that sequesters 50% of its CO_2 for facilities beginning operation before 2016, 70% for facilities starting up in 2016 and 2017, and 90% for facilities commencing operation after 2017	CO_2 (also SO_2, NO_x, PM, CO, and Mercury)	LSEs	Sourcing agreements with "clean coal" facilities must be filed with procurement plans

4. QUALITATIVE ANALYSIS OF POTENTIAL CES POLICY DESIGNS

After cataloging the forms that CES policies have taken in the United States and abroad, Synapse performed a qualitative assessment of potential CES design options for Massachusetts, including detailed analysis of the two policy designs found to be most feasible. Six potential CES designs for Massachusetts were identified: (1) performance standards for power plants; (2) performance standards for suppliers; (3) portfolio standards for suppliers; (4) limiting long-term contracts with high-emissions generators; (5) requiring long-term contracts with low-emissions generators; and (6) requiring suppliers to purchase and retire Regional Greenhouse Gas Initiative (RGGI) allowances. Table 12 introduces each design in turn.

Table 12: Potential CES Designs

CES Design	Description
#1: Set Power Plant Emission Standards	Standard applied to power plants requiring them to maintain emission rates below a given level.
#2: Set an LSE Performance Standard	Standard applied to LSEs requiring them to meet an average emission rate for their load.
#3: Set an LSE Portfolio Standard	Standard applied to LSEs requiring them to cover some portion of their sales with credits from specific resources.
#4: Limit Long-Term Contracts	Standard applied to LSEs prohibiting them from investing in, or signing long-term contracts with, CO_2 intensive sources
#5: Require Long-Term Contracts	Standard applied to LSEs requiring them to enter into long-term agreements with low-emissions generators.
#6: Require LSEs to Buy RGGI Allowances	Standard applied to LSEs requiring them to purchase and retire RGGI allowances.

From these six designs, the second and third—the LSE performance standard and the LSE portfolio standard—were determined to be the most feasible for Massachusetts. Detailed qualitative analysis revealed several serious practical concerns with implementing an LSE performance standard in the Commonwealth. For this reason, the modeling described in Section 4 was conducted only on the LSE portfolio standard design.

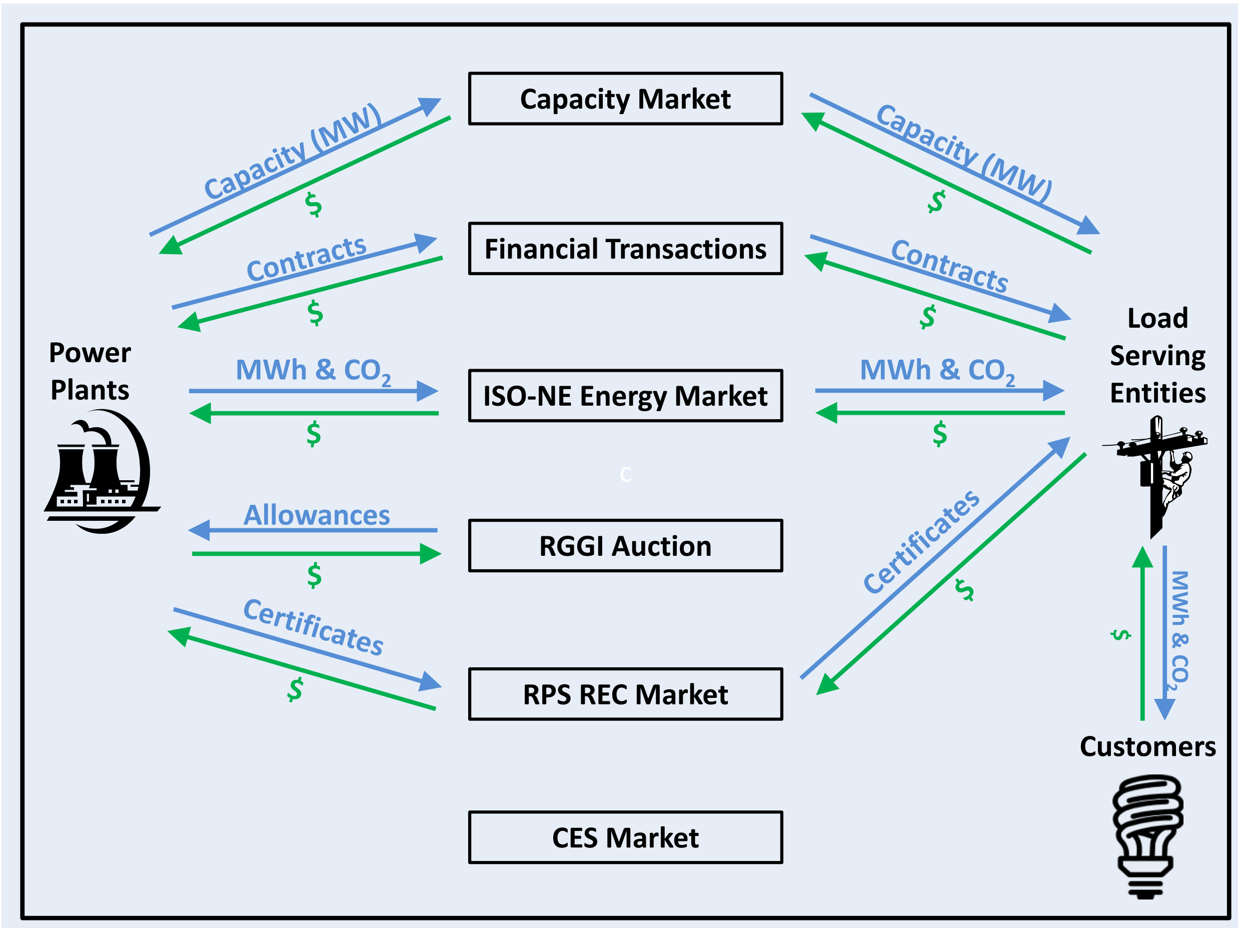
In this section, we discuss our qualitative analysis of the six CES design options beginning with an overview of impacts that CES regulation would have on the dynamics of the electricity sector.

4.1. CES Impacts on the Electricity Sector: An Overview

Electricity-Sector Dispatch and Investment

The system dynamics of any change to an electricity-sector market can be complex, and changes in one electricity-sector market—energy, capacity, financial transactions, RGGI auctions, RECs—tend to have impacts on many of the related markets. In order to capture these interactions, CES design will be described in this report in terms of its effects on the various electricity-sector markets, as shown in Figure 2.

Figure 2. Electricity-Sector Markets Schematic



Source: Developed by study authors

A CES policy works by causing a shift in the dispatch of electricity generation (when and how much each generating unit operates), a change in expected investment or retirements, or both. A CES can affect plant operating costs, bid prices, and—as a result—capacity factors. LSE-based standards require electricity suppliers to demand more low-CO_2 generation, increasing the hours of operation of these resources. All CES design options considered have the potential to shift the regional generation mix—in the short-run by shifting dispatch, and in the longer run by changing the incentives for what types of generation resources are built.

A shift in dispatch

New England electricity generators submit bids to the ISO-NE each day for how much electricity they are willing to produce at what prices. Their bid prices are required to be the variable cost (i.e., excluding capital costs) of producing a MWh of electricity. ISO-NE creates a "bid stack," lining up the generators' bids from the least to the most expensive, and—beginning with the least expensive bid—accepts the bids necessary to meet that day's forecasted retail sales of electricity. A shift in dispatch is a change in the composition of the bid stack either in generators' bid prices or in the amount of electricity that a generator is willing to produce for a given price. Given a fixed set of generators bidding into a system (that is, assuming that there will be no new investment or retirements) and fixed retail sales, electricity greenhouse gas emissions will not change unless dispatch—how much each resource generates—changes. Emissions change when generation from high-CO_2 plants is replaced with generation from low-CO_2 plants.

Many examples of shifts in dispatch discussed in this report involve CES certificate prices that, when included in variable costs, change a generator's bid price. It is important to recall, however, that not just any change to variable cost will shift dispatch. In order to change dispatch and, therefore, emissions, variable costs must change sufficiently to cause two or more resources to swap places in the bid stack. Smaller changes to variable cost may affect power-plant revenues and, as a result, incentives for future investments, but leave dispatch unaffected.

A change in expected investment or retirements

CES policies may also cause a change in expected investment either indirectly as a result of shifts in dispatch, or directly via limitations or requirements regarding long-term contracts and investments in generation resources. Increased revenues or additional long-term contracts for certain types of resources spur investment in these technologies, while reduced revenues or fewer long-term contracts can result in additional retirements for particular resource types.

Understanding Power-Plant and LSE Implementation

A CES policy may be applied either to power plants (supply-side regulation) or LSEs (demand-side regulation). In this section, we review the pros and cons of power-plant versus LSE implementation of a Massachusetts CES, focusing on probable emissions and economic impacts.

Supply- and demand-side CES differ in several ways, as summarized in Table 13.

Table 13. Comparison of Supply- and Demand-Side CES

Characteristic	Supply-side CES	Demand-side CES
Emission reductions	Would occur in Massachusetts and would be reflected in the Commonwealth's Greenhouse Gas Emissions Inventory	Could occur throughout ISO-NE and even beyond, and may or may not be captured in the Commonwealth's Inventory
Verifying compliance	Could be accomplished with an existing MassDEP or EPA system	Would require some form of tracking system
Costs to ratepayers	Would be spread across the region	Would be limited to Massachusetts ratepayers
Changes in power plant revenues	Would be limited to Massachusetts power plants	Would be spread across the region
Offsets	Could be designed to allow or disallow offsets, and written to restrict emission reductions to within-Massachusetts sources.	

Supply-Side CES: Regulating Power Plants

Emission standards applied to power plants typically require generators to adopt a certain technology or meet a defined emission rate. Currently, most supply-side CES policies apply only to new or expanded plants. Canada's power-plant performance standard is unique in that it applies to certain existing plants as well as new ones. Massachusetts regulators have the authority to establish a CO_2 performance standard for new facilities in the state.[73] It is, however, unlikely that any company is considering construction of a new coal-fired plant in Massachusetts, so a standard set with the goal of preventing new coal construction such as those implemented in other jurisdictions would likely have no impact on emissions. A new-source performance standard would likely only have an effect in Massachusetts if the performance standard were set low enough to exclude certain natural gas generation technologies from being built in Massachusetts or to require CCS at new gas plants or higher emitting power generators.

Performance standards applied to existing plants are more complex. Power plants currently have few cost-effective options for reducing CO_2 emission rates (e.g., oil and coal-fired units that can also combust gas could increase gas combustion; this is not an option for gas-fired units). Thus, their only opportunity for compliance in many cases would be to close, unless alternative compliance pathways are allowed. One potential compliance pathway would be the use of greenhouse gas offsets.[74] Offsets are credits for emission reductions achieved offsite, usually via emission reduction or carbon sequestration projects. Many CO_2 programs allow sources to treat offsets as if they were onsite emission reductions, effectively reducing plant emission rates.

Plant retirements and/or offsets would reduce CO_2 emissions in Massachusetts, and would be captured in the Commonwealth's Greenhouse Gas Emissions Inventory, which assumes that all generation at

[73] Chapter 298 of the Acts of 2008. https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter298.

[74] Massachusetts had a CO_2 performance standard and offset program affecting the six largest Massachusetts power plants (part of regulation 310 CMR 7.29 *Emissions Standards for Power Plants*), but this program was phased out with the advent of RGGI.

Massachusetts power plants is consumed in Massachusetts. In Section 4.4, we examine ways in which such reductions would interact with the RGGI emissions cap. A performance standard that allowed for offsets would generate CO_2 reductions through offset projects. As an additional measure, a CES could limit offsets to projects located in Massachusetts, improving the chance that financial benefits from these investments would remain within the Commonwealth, but this restriction would also make offsets more expensive and would require careful oversight to avoid double-counting of offsets with other existing climate strategies.

To verify compliance with a supply-side CES in Massachusetts, regulators could use the Massachusetts Department of Environmental Protection (MassDEP) existing greenhouse gas reporting system. This idea is discussed further in Section 4.3.

The economic impacts of a supply-side CES may be viewed from the point of view of either electricity ratepayers or generators. A performance standard for power plants would increase the cost of electricity generation in Massachusetts, but this increase would not be born entirely by Massachusetts ratepayers. New England pools its generation resources, so the increased generation costs would likely be shared by ratepayers outside Massachusetts. For generators, however, costs would be limited to companies operating high-emitting plants in Massachusetts; these companies would incur the cost of either plant retirements or offset projects.

Demand-Side CES: Regulating Load-Serving Entities

A CES applied to LSEs reduces emissions indirectly, by requiring LSEs to purchase more low-CO_2 electricity, increasing demand for low-CO_2 energy and reducing demand for high-CO_2 energy. There are four basic demand-side CES designs.

- LSEs can be required to meet a “performance standard,” to purchase electricity for resale with an average emission rate below a specified level.
- LSEs can be required to meet a “portfolio standard,” to purchase a certain percentage of electricity from certain types of plants, defined in the standard.
- LSEs can be prohibited from entering into certain types of contracts or investments.
- LSEs can be required to enter into certain types of contract or investments.

LSE-based performance and portfolio standards can also allow for offsets. In this case, LSEs would comply by purchasing more low-CO_2 electricity and/or investing in offset projects. While here we compare the emissions and economic impacts of these demand-side CES designs, the policies also differ in the level of support they provide to new renewable and low-CO_2 power projects.

Emission reductions from a demand-side CES would be spread throughout New England or even beyond. Because Massachusetts LSEs purchase electricity from plants throughout the ISO-NE region, these emission reductions might or might not be reflected in the current Massachusetts Greenhouse Gas Inventory. Again, potential interactions between emission reductions and the RGGI program are discussed in Section 4.4.

In terms of compliance, unlike supply-side performance standards, demand-side CES designs require a system for suppliers to determine and report the sources of the electricity they purchase for resale. A standard that required LSEs to maintain a percentage of low-CO_2 generation or a portfolio average emission rate would require a system of tradable certificates. A standard that prohibits certain types of investments or contracts, however, would require mandated reporting of investments and long-term contracts. Potential tracking systems for Massachusetts are discussed in detail in Section 4.3.

A CES applied to LSEs would have the same types of economic impacts as one applied to power plants, but the impacts would be distributed differently. With a demand-side CES, Massachusetts LSEs would pass the increased supply costs directly to their customers—all of whom would be in Massachusetts. These increased generation costs would impact only Massachusetts rate-payers. From the generators' perspective, however, changes in revenues would occur at power plants throughout the ISO-NE region. Note that the distribution of impacts from demand-side implementation is the reverse of the distribution from supply-side implementation; with supply-side CES designs, rate impacts are dispersed across the region but changes in power plant revenues are concentrated in the state with the standard.

4.2. Comparing Performance and Portfolio Standards

Regulatory designs for limiting greenhouse gas emissions fall into two categories: those based on average emission rates (performance standards) and those applied to a certain share of suppliers' retail sales (portfolio standards). This section examines the workings of each type of standard in terms of technical feasibility and political viability for Massachusetts. Section 4.3 discusses concerns with shuffling under a Massachusetts portfolio standard.

Performance Standards

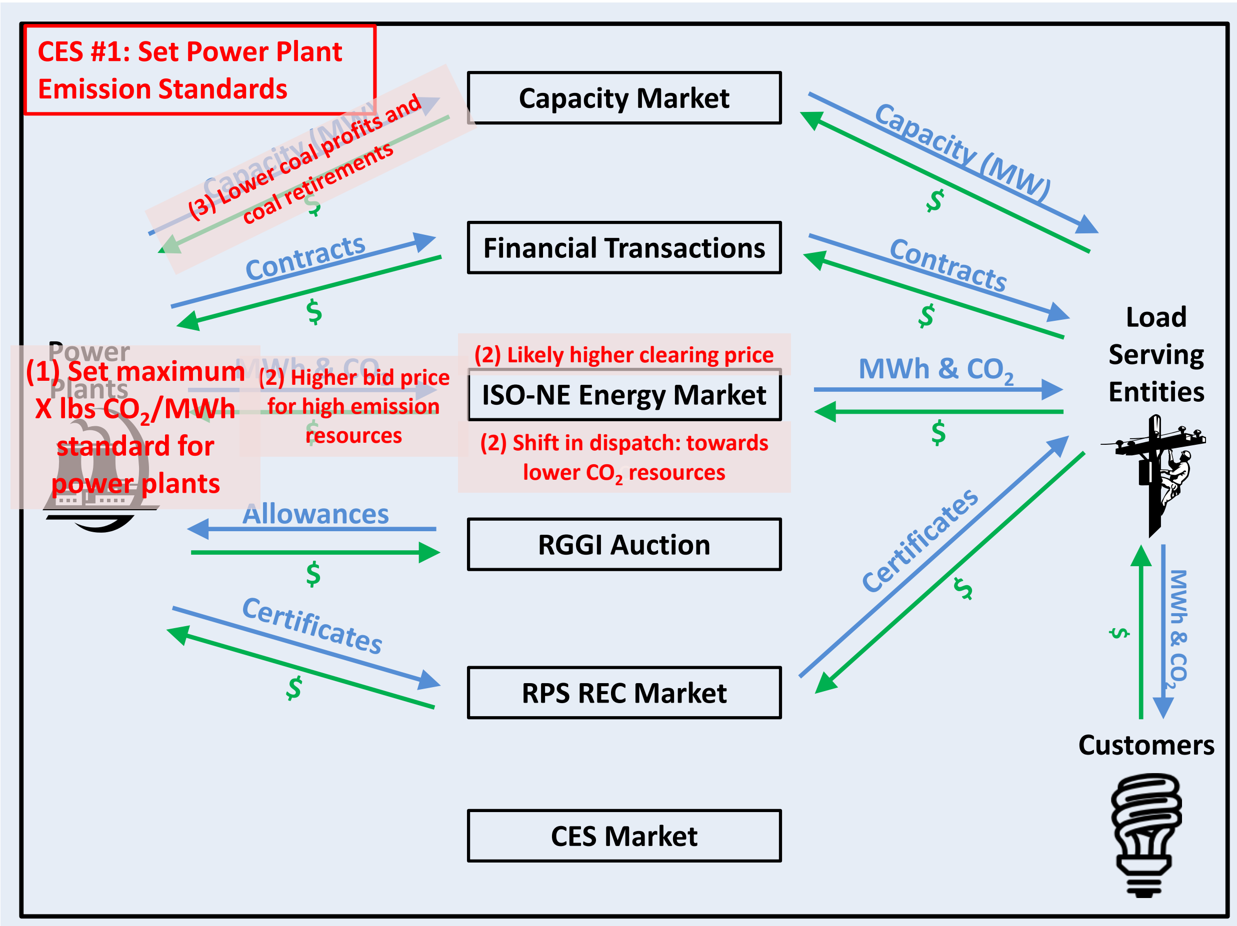
A performance-standard-based CES sets a requirement that energy, either provided or purchased, be at or below a specified average lbs/MWh CO_2 emission rate. In principle, performance standards may be applied to either generators or LSEs; however, as discussed in this section, demand-side implementation is complicated and lacks any known precedent.

Performance standards for generators

Supply-side implementation—requiring power plants to maintain emission rates at or below a lbs/MWh standard—is relatively straightforward: Public policy mandates a maximum emission rate and generators are obligated to comply. The United Kingdom, Canada, and New York have lbs/MWh performance standards for new or newly expanded power plants; Canada's standard also applies to existing plants 50 years or older.

Figure 3 illustrates a CES requiring power plants to maintain emission rates below a given lbs/MWh standard (refer back to Figure 2 for a version of this diagram without the superimposed red text describing the CES design). This type of standard could either result directly in high-emission plants retiring or, as shown in the schematic, CCS or other emission-reduction methods could raise the bid price for high emission resources, shifting dispatch towards lower-emission resources. A higher bid price that did not clear in the energy market on a particular day would also mean lower revenues for these plants, and a reduced incentive for investments in these types of technologies.

Figure 3: CES #1: Set Power Plant Emission Standards Schematic



Source: Developed by study authors

In the case of a Massachusetts CES, there are several important nuances in policy design. First, as discussed above, a supply-side performance standard for existing generators would force plants with emission rates above the legal threshold to close or, for future-year standards, make plans to install still-developing CCS technologies. A performance standard that permitted offsets could allow high-emitting plants to continue operating while meeting the standard. Second, Massachusetts regulators only have the authority to regulate plants in Massachusetts. Therefore, they can only affect a small number of the high-emitting plants in the region. In contrast, a standard applied to LSEs serving Massachusetts may have the potential to affect the highest emitting plants in the region, regardless of where those plants are located. This is because Massachusetts LSEs purchase electricity from plants throughout ISO-NE, and the Commonwealth's LSEs sell considerably more electricity than Massachusetts plants generate.

A third important consideration is the level of aggregation at which the emission rate is applied. From the plant owner's point of view, a performance standard set at the individual unit level requires the most effort for compliance. In contrast, a standard that applies to the average emission rate of a multi-unit plant or to the average across all units—and resource types—in an owner's fleet allows more flexibility in compliance and may, therefore, result in less overall emission abatement. A lbs/MWh standard applied at the fleet level to GenOn, for example, would set a maximum emissions rate for average emissions across GenOn's Massachusetts oil and gas units (or, if the CES were applied to the region as a whole, to its coal, natural gas, and oil units), and would allow the company to change the composition or output of its Massachusetts-based fleet with the goal of reducing this rate. Similarly, standards may vary in whether they require a particular emission rate for a particular year or whether the rate may be averaged over multiple years of operation, as is the case in the EPA's proposed New Source Performance Standard.

MassDEP's facility greenhouse gas reporting requirements appear sufficient to support a performance standard in the Commonwealth with very little modification. Some Massachusetts generators also report information to the EPA and RGGI "COATS" system (discussed in Section 4.3), and MassDEP's greenhouse gas reporting regulation requires such plants to verify that they are reporting the same data to EPA and MassDEP. Each unit could be assigned its actual emission rate—based on data reported to EPA and MassDEP—or, alternatively, units could be assigned the average New England emission rate for their class of plant. Because the latter system would not give plants credit for improvements in their emission rates, it would tend to prioritize retirements or CCS installation (thereby changing the class of the plant) over changes in unit efficiency with associated incremental reductions in emission rates. MassDEP's requirements would dictate the minimum capacity below which plants are excluded from CES compliance, and the reporting requirements could be amended if necessary to apply to additional plants in the Commonwealth to encompass units subject to a CES.

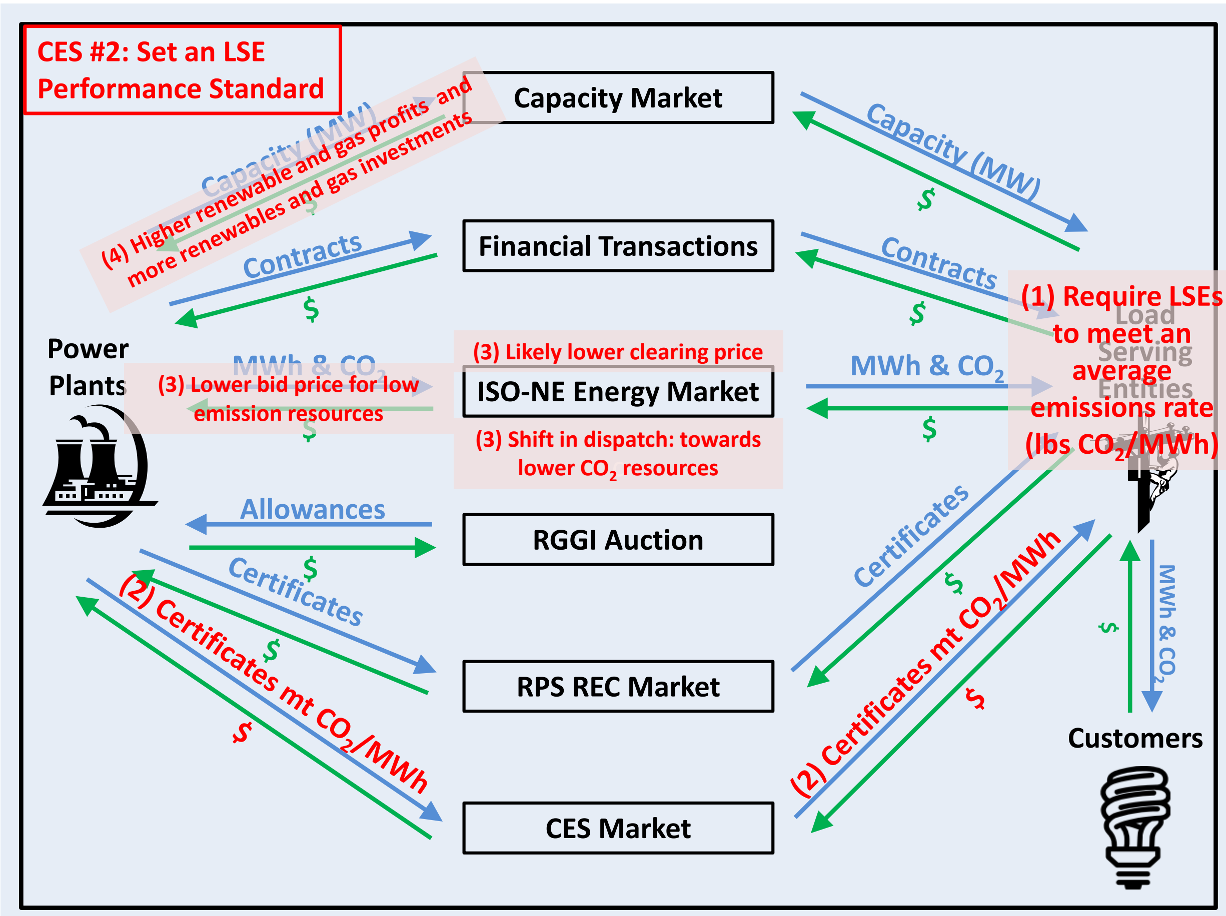
As discussed below, a supply-side CES may be politically infeasible for Massachusetts because of the time and effort involved in achieving the recent changes to the RGGI cap and trade system.

Performance standards for LSEs

Demand-side implementation—requiring each LSE to maintain an average emission rate at or below a lbs/MWh standard—is a more complicated proposition. Under this policy design, Massachusetts LSEs must purchase lbs/MWh-denominated certificates from New England (and, potentially, certain Canadian) power plants. Two systems for assessing an LSE's average emission rate seem most plausible: (1) LSEs must purchase a lbs/MWh certificate for every MWh sold; or (2) LSEs have the option of purchasing certificates and are assigned the residual average emission rate for the MWh for which they do not have certificates. Our review of CES designs employed in other jurisdictions did not reveal any existing demand-side performance standard policies, and our own analysis of this option is that it may prove impractical to implement.

Figure 4 illustrates a CES policy requiring LSEs to meet an average emissions rate for their retail sales. Compliance verification for such a policy would require LSEs to purchase certificates for low-emission MWh (in addition to their purchase of RECs); LSEs would receive the residual average emission rate for MWh sold for which they do not own a CES or REC certificate. Revenues to low-emission generators from the CES certificate market would lower their bid prices and shift dispatch in their favor. Lower bid prices coupled with more frequent dispatch would also result in higher profits for low-emission resources, and more incentive for investment in lower-emitting technologies like renewables and natural gas.

Figure 4: CES #2: Set an LSE Performance Standard Schematic



Source: Developed by study authors

If LSEs are required to purchase certificates for every MWh sold, the market for certificates may become more difficult to implement as the total demand for certificates approaches the total supply of certificates. In a demand-side performance standard applied to all of New England (with Canadian sources excluded from selling certificates), for example, every certificate in circulation would be required for purchase. LSEs could find it challenging to purchase a mix of certificates with the desired average emission rate, and certificate prices would likely include a cost associated with this "administrative friction"—that is, the potential costly challenge of connecting sellers to buyers in this complex market. Even in a Massachusetts-only CES, in which LSEs serving the Commonwealth would require about half of the certificates produced, competition for the more desirable, low-emission rate certificates could be high. While strong competition leading to high certificate prices and robust incentives for investment in low-emissions generation resources is important to success in CES emission reductions, administrative friction could reduce the certificate market's efficiency, raising the cost per unit of emissions eliminated.

A CES in which LSEs are assigned the residual average emission rate for the MWh for which they have not purchased certificates would come with its own administrative hurdles. (As noted below in Section 4.3, LSEs in New England currently rely on the residual average—the characteristics of all the certificates not sold—to reduce the compliance burden of disclosure requirements.) The residual average emission rate cannot be known until after certificate trading is closed. LSEs, therefore, would be buying certificates without knowing the residual rate—making it difficult to tailor purchases with the goal of achieving a particular lbs/MWh average for their retail sales. A "true-up" period of additional trading could partially resolve this problem but, again, the post-true-up-period residual would not be known until true-up trading was closed. As a result, LSEs would need to make their certificate purchases using a conservative (high) assumption regarding the residual emission rate, which, on the whole, would likely result in higher than required emission reductions for Massachusetts.

Whether or not LSEs are required to purchase a certificate for each MWh sold, the market for these lbs/MWh certificates would be difficult both to administer and to participate in, for buyers and sellers alike. Unlike buying and selling MWh of electricity, RGGI allowances, or RECs—or any typical, homogenous market commodity—each plant would be issued certificates with unique emission rates (as is the case in the existing NEPOOL GIS tracking system). There would be no single price for a certificate, but rather a different price for each certificate with a different emission rate. While complex markets exist for sets of similar products with varying attributes—consider the "market for coal," which is really a group of interrelated markets for coals of varying heat rates and sulfur contents—we are not aware of a government-administered market for a non-homogenous allowance, credit, or certificate. The prices of these non-homogenous CES certificates would be interrelated but might not be proportional to their emission-rate "face value."

Despite their administrative difficulties, lbs/MWh performance standards may nonetheless be considered an attractive policy option because they have the benefit of being, on the surface, "technology neutral." A CES policy is technology neutral if all electricity generating technologies are allowed to participate, and their participation is managed by a technology-independent criterion such as carbon intensity, as opposed to a CES policy that does not allow certain technologies to participate.

It is, however, important to note that while lbs/MWh is a neutral metric, the selection of the standard's level of lbs/MWh stringency will be made with full knowledge of the respective emissions rates of each resource type and class of plants. A performance standard's emission rate threshold could be set with the goal of achieving a certain level of emission reductions, or with the goal of excluding certain technologies from receiving credits. Setting a performance standard at 2,000 lbs/MWh (slightly lower than the typical emission rate of a conventional coal plant) will have a very different impact on dispatch by technology type than would a 800 lbs/MWh standard (slightly lower than the typical emission rate of a combined-cycle gas plant). As discussed in the next section, performance standards are no more technology neutral in their application than are portfolio standards.

Portfolio Standards

Portfolio-standard-based CES policies apply to LSEs (and not power plants), and regulate the emissions mix or composition of the fuel use of each LSE's "portfolio" of generation resources. Three types of portfolio standards exist:

1) **LSEs must maintain a particular fuel or resource-type mix, or minimum or maximum shares of retail sales from certain fuel or resource types.** RPS policies, an increasingly common example of this type of policy design, use RECs as a compliance currency, where each REC represents 1 MWh of renewable electricity. LSEs comply with the RPS by purchasing and retiring RECs equal to the compliance level as compared to their sales. For example, if an LSE had 1,000 MWh of sales and the RPS requirement were 10 percent in a given year, then the LSE would be obligated to purchase and retire 100 RECs in that year. Massachusetts' RPS requires LSEs to purchase eligible Class I RECs equal to 15 percent of their retail sales in 2020, with the requirement rising by 1 percentage point each year thereafter. Connecticut, New Hampshire, Maine, Massachusetts, Rhode Island and Vermont—among many other states across the Unites States—all have RPS policies. The goal of the Massachusetts CES, however, as described in the CECP, is to reduce emissions over and above those reductions effected by the RPS and other existing policies, and Massachusetts' RPS is already one of the most stringent in the country for years after 2020.[75]

2) **LSEs must achieve a particular share of zero-CO_2 generation, where all electricity supply is defined as either CO_2 emitting or CO_2 non-emitting.** An example of this type of policy for Massachusetts would be setting a 25 percent non-emitting requirement for each LSE's retail sales. In 2020, for an LSE with 1,000 MWh in sales, the first 150 MWh of non-emitting generation would be covered by the LSE's RPS compliance—and subject to the particular dictates of the RPS's specifications for allowable renewables—and the remaining 100 MWh could come from any non-emitting source, including nuclear and large, existing hydro. As discussed in Section 4.3, the best verification system for this policy design would be the NEPOOL GIS system.

3) **LSEs must achieve a particular share of low-CO_2 generation, where electricity supply is characterized by its emission levels.** This type of portfolio standard is the system proposed in the Obama and Bingaman Clean Energy Standards, which would create a new, national certificate trading program in Massachusetts. NEPOOL GIS would allow verification of such a standard.

This third portfolio standard design has the virtue of being "technology neutral" in the same sense that performance standards are technology neutral (see above). While more simplistic methods for assigning

[75] See DSIRE: Database of State Incentives for Renewables & Efficiency website, http://www.dsireusa.org/

certificate values exist (e.g., 1.0 credits/MWh for renewables and 0.5 credits/MWh for natural gas), the credit assignments may instead be made in proportion to each resource's effective emission reduction in relation to the average emissions rate of a particular resource or class of resources (see Table 14).

Table 14: Assignment of Portfolio Standard Credits

Threshold Resource: Natural Gas Combustion Turbine (1,300 lbs/MWh)

Resource Type	Resource Emission Rate (lbs/MWh)	Gas CT Plant Emission Rate (lbs/MWh)	Effective Emission Reduction (lbs/MWh)	Potential "Avoided Emission" Credits per MWh
	a	*b*	*b - a*	*(b - a)/b*
Nuclear	0	1,300	1,300	1.00
Hydro	0	1,300	1,300	1.00
Solar	0	1,300	1,300	1.00
Wind	0	1,300	1,300	1.00
Gas CC	1,100	1,300	200	0.15
Gas CT	1,300	1,300	0	0.00
Oil ST	1,900	1,300	0	0.00
Coal ST	2,200	1,300	0	0.00

Threshold Resource: Oil Steam Turbine (1,900 lbs/MWh)

Resource Type	Resource Emission Rate (lbs/MWh)	Oil ST Emission Rate (lbs/MWh)	Effective Emission Reduction (lbs/MWh)	Potential "Avoided Emission" Credits per MWh
	a	*b*	*b - a*	*(b - a)/b*
Nuclear	0	1,900	1,900	1.00
Hydro	0	1,900	1,900	1.00
Solar	0	1,900	1,900	1.00
Wind	0	1,900	1,900	1.00
Gas CC	1,100	1,900	800	0.42
Gas CT	1,300	1,900	600	0.32
Oil ST	1,900	1,900	0	0.00
Coal ST	2,200	1,900	0	0.00

Threshold Resource: Coal Steam Turbine (2,200 lbs/MWh)

Resource Type	Resource Emission Rate (lbs/MWh)	Coal ST Emission Rate (lbs/MWh)	Effective Emission Reduction (lbs/MWh)	Potential "Avoided Emission" Credits per MWh
	a	*b*	*b - a*	*(b - a)/b*
Nuclear	0	2,200	2,200	1.00
Hydro	0	2,200	2,200	1.00
Solar	0	2,200	2,200	1.00
Wind	0	2,200	2,200	1.00
Gas CC	1,100	2,200	1,100	0.50
Gas CT	1,300	2,200	900	0.41
Oil ST	1,900	2,200	300	0.14
Coal ST	2,200	2,200	0	0.00

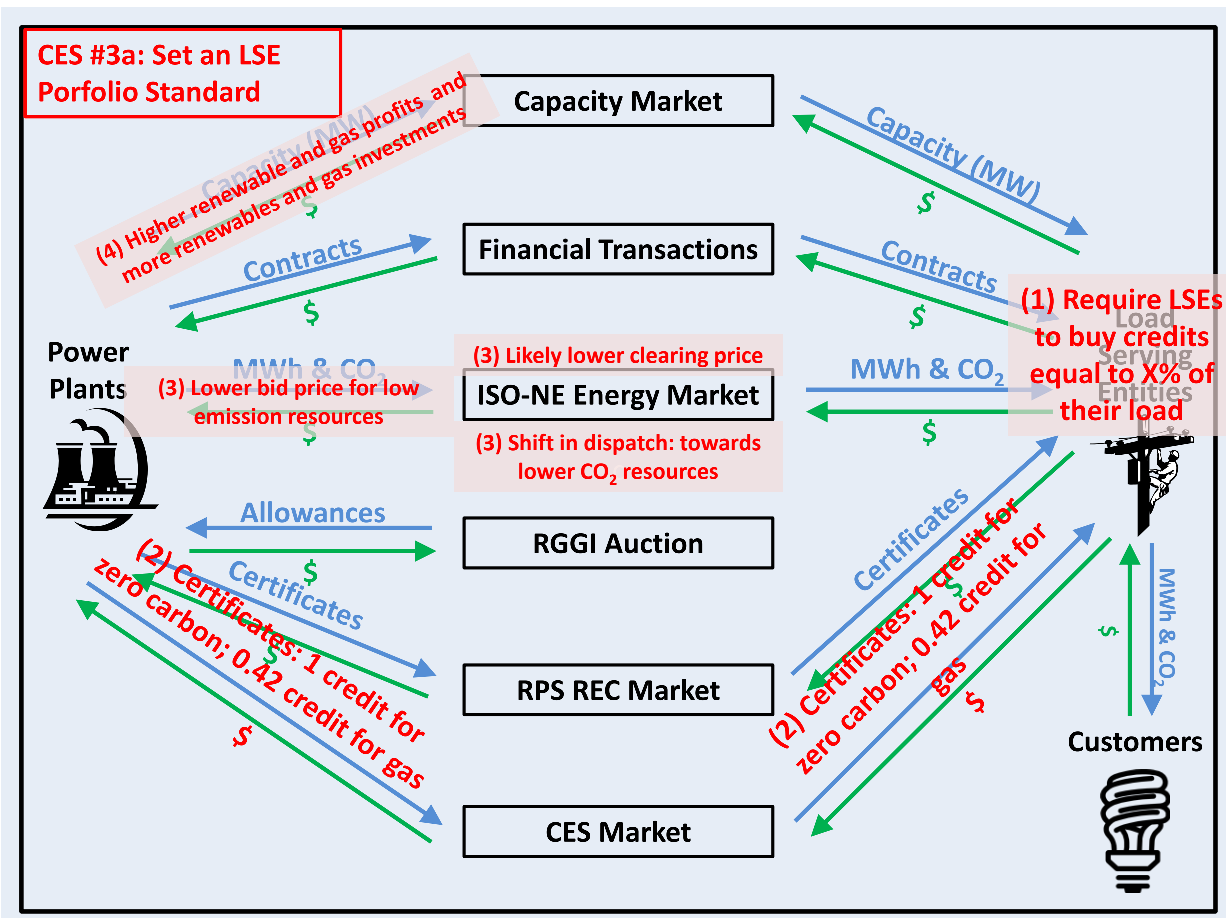
Source: EIA Form 860 2012; AMP Data 2012.

Table 14 reports typical (not unit-specific) credits assignments in relation to three different threshold resources using New England average resource-type emissions rates: natural gas combustion turbine (1,300 lbs/MWh); an oil steam turbine (1,900 lbs/MWh); and a coal steam turbine (2,200 lbs/MWh). For example, Fore River Station 1, a natural gas combined-cycle plant with a 838 lbs/MWh emission rate, has a 1,362 lbs/MWh effective emission reduction when compared to the 2,200 lbs/MWh emission rate of the average New England coal plant. Fore River Station 1 would receive a 0.36, 0.56, or 0.62-credit certificate for each MWh of generation, respectively, depending on the choice of threshold resource.

Effects on dispatch and investment

Figure 5 illustrates a CES policy requiring LSEs to buy credits in a new CES-certificate market equal to a given percentage of their retail sales, where it is assumed that RECs will be accepted as equivalent to CES credits. (To be clear, LSEs would first satisfy CES requirements using REC purchased for RPS compliance before purchasing additional CES credits.) Revenues to low-emission generators from the CES certificate market would lower their bid prices and shift dispatch in their favor.

Figure 5: CES #3a: Set an LSE Portfolio Standard in a CES Market Schematic

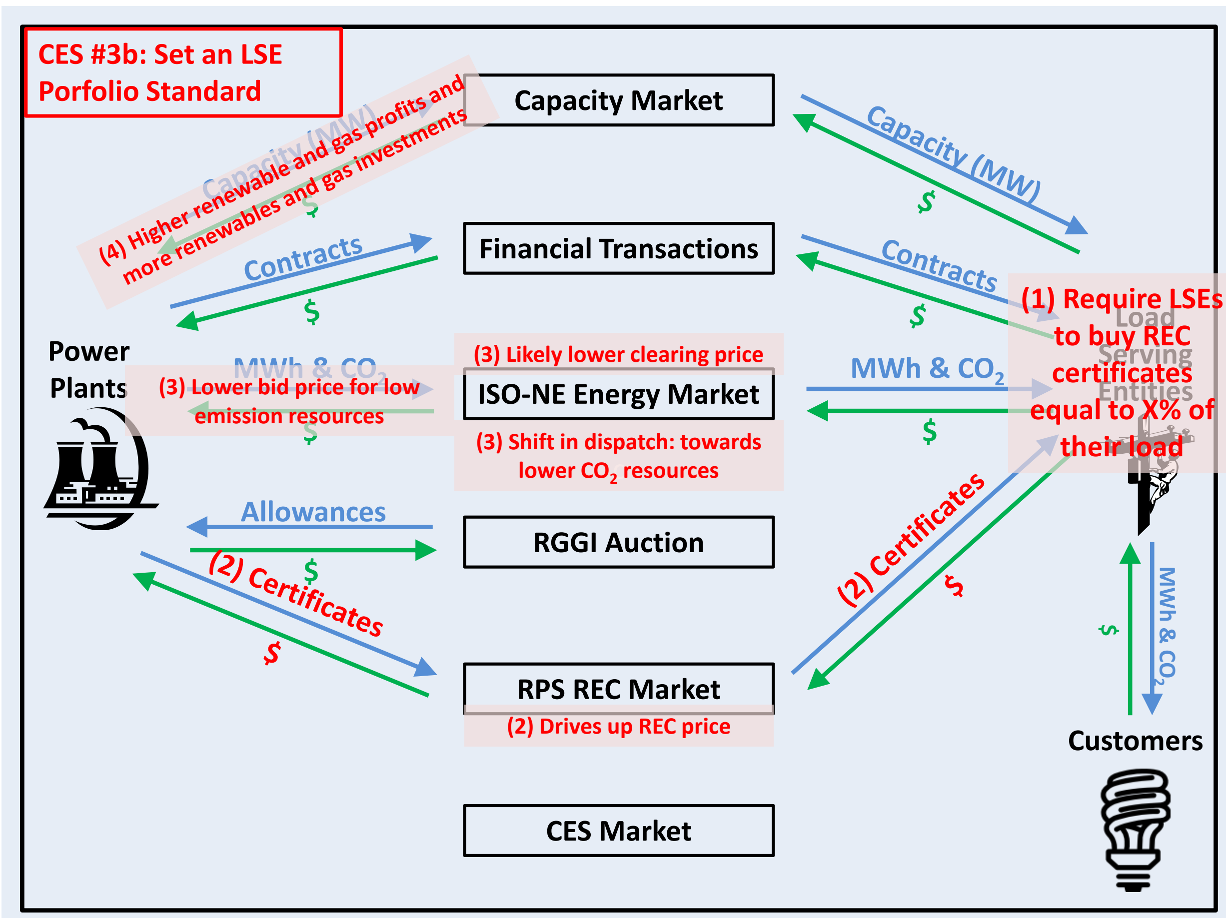


Source: Developed by study authors

Lower bid prices coupled with more frequent dispatch would also result in higher profits for low-emission resources, and more incentive for investment in lower-emitting technologies like renewables and natural gas.

Alternatively, a portfolio standard could be designed to be implemented in the existing RPS REC market, although still administered as a stand-alone CES program. Figure 6 illustrates a process that has identical market impacts to a CES portfolio standard with a separate market, although this schematic draws attention to a key impact in either portfolio standard design: the effect on REC prices. Any CES design that accepts REC certificates for compliance will tend to increase REC prices.

Figure 6: CES #3b: Set an LSE Portfolio Standard in the REC Market Schematic



Source: Developed by study authors

4.3. Verifying Compliance with a CES

Every form of CES design requires a system for verifying compliance. The following table summarizes the verification options available for each of the studied CES designs.

Table 15: Methods of Verification for CES Design Options

CES Design	Methods for Verifying Compliance
#1: Set Power Plant Emission Standards	Verification could be accomplished using existing MassDEP or EPA tracking systems. Few changes to the MassDEP reporting requirements, if any, would be needed. Information collected by the RGGI COATS system could be used to crosscheck CES data reported to MassDEP.
#2: Set an LSE Performance Standard	Verification would require a system of tradable certificates. Compliance would be difficult to verify, even using the existing NEPOOL GIS tracking system, as Massachusetts only has authority to require reporting by units located in the Commonwealth.
#3: Set an LSE Portfolio Standard	Verification would require a system of tradable certificates. NEPOOL's GIS system could potentially be used for this purpose, if its emission reporting procedures could be modified to meet the standards of Massachusetts regulators.
#4: Limit Long-Term Contracts	Verifying that LSEs have not entered into certain long-term contracts or investments would require LSEs to submit all such contracts or investments for review. A proposal for such a requirement would likely meet with considerable resistance, and the review process could be quite resource intensive.
#5: Require Long-Term Contracts	Verifying that LSEs or distribution companies have entered into long-term contracts or made investments in certain technologies is relatively more straightforward: Suppliers would be required to present evidence of these arrangements.
#6: Require LSEs to Buy RGGI Allowances	Verification would be accomplished using RGGI COATS.

Verifying Compliance with a Supply-Side CES

Several requirements for greenhouse gas reporting currently apply to power plants in Massachusetts:

- Most plants report emissions to the MassDEP and plants over 25 MW report emissions to EPA pursuant to the federal Acid Rain Program at Title IV of the Clean Air Act Amendments of 1990 and to the interstate agreements regarding RGGI.
- In addition, EPA requires facilities emitting 25,000 or more metric tons of CO_2e to report greenhouse gas emissions.

These existing reporting requirements could support a supply-side CES in Massachusetts with minimal additions or changes.

MassDEP's greenhouse gas reporting requirements

In compliance with the Massachusetts GWSA, the MassDEP promulgated greenhouse gas reporting regulations.[76] Sources required to report include:

[76] These regulations are at 310 CMR 7.71, available at: http://www.mass.gov/dep/service/regulations/310cmr07.pdf.

- Facilities (both power plants and other sources) that emit more than 5,000 sT per year of CO_2-equivalent;
- Facilities that report air emissions pursuant to the Massachusetts Air Operating Permit Program;[77] and
- Facilities that have reported greenhouse gas emissions in any past year.

These sources are required to report greenhouse gas emissions to MassDEP by April 15th of each year for the previous calendar year. Reporting is required for CO_2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons. Biogenic and non-biogenic greenhouse gas emissions are reported separately.[78]

Facilities report their greenhouse gas emissions using the Massachusetts Greenhouse Gas Registry, a regional electronic reporting system built on the Climate Registry's Climate Registry Information System (CRIS) software platform.[79] CRIS is an internet-based application that simplifies greenhouse gas emission calculations by automating many of the reporting requirements. CRIS tracks greenhouse gas emissions data over time and produces reports for both emitting facilities and interested stakeholders.

Facilities report their greenhouse gas emissions in accordance with the Climate Registry's General Reporting Protocol, which requires them to record emissions from their operations in the United States, Canada, and Mexico at the facility level. MassDEP further requires separate reporting of emissions from each stationary source at each facility. Every third year, affected sources must have emissions verified by an approved third-party auditor. Verification is done in accordance with the requirements of the Climate Registry's General Verification Protocol. Units that report CO_2 emissions under RGGI simply report the same value to the Massachusetts Greenhouse Gas Registry.

The RGGI "COATS" tracking system

RGGI is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO_2 emissions

---

[77] Facilities that are required to report air emissions pursuant to the MA Air Operating Permit Program include: (1) facilities that emit 50 tons per year of VOC or NOx, ten tons per year of any hazardous air pollutant, 25 tons per year of any combination of hazardous air pollutants, or 100 tons per year of other regulated air pollutant; (2) facilities that are subject to requirements under 42 U.S.C. 7401, § 112 (NESHAPS) (accidental release); (3) facilities that are subject to a New Source Performance Standard; (4) facilities that are affected sources as defined in 42 U.S.C. 7401, Title IV (acid rain provisions); or facilities in any other source category designated by the EPA pursuant to 40 CFR, § 70.3(a)(5). 310 CMR 7.00, Appendix C, (2)(a).

[78] MassDEP defines biogenic greenhouse gas emissions as CO_2 that results from the combustion of biogenic (plant or animal) material, excluding fossil fuels. Non-biogenic greenhouse gas emissions include CO_2 released from the combustion of non-biogenic fuel, plus CH_4 and N_2O released from the combustion of any fuel.

[79] The Climate Registry is a nonprofit collaboration among North American states, provinces, territories and Native Sovereign Nations that sets consistent and transparent standards to calculate, verify and publicly report greenhouse gas emissions into a single registry. http://www.theclimateregistry.org/

from the electric power sector.[80] All fossil-fuel power plants with a capacity of 25 MW or greater located within RGGI states must hold one allowance for each ton of CO_2 that they emit.[81] Each RGGI state issues allowances in an amount defined in the state's statutes or regulations. Together, all the allowances issued by all the RGGI states make up the regional cap.[82] Nearly all allowances are offered for sale in quarterly regional auctions. States retain some allowances as "set-asides," which are either allocated to sources at the state's discretion or retired at the end of the trading period.

Affected sources report emissions via the RGGI CO_2 Allowance Tracking System (COATS). Each plant subject to RGGI reports hourly emissions data to the EPA Clean Air Markets Division database, in accordance with state CO_2 Budget Trading Program regulations and EPA regulation 40 CFR Part 75. Hourly data are reported in three-month increments, within four weeks of the end of the quarter. It takes EPA an additional four weeks to transfer the data to COATS.[83] For example, hourly data from October 1, 2012 through December 31, 2012 was reported to EPA in January 2013, processed by EPA in February 2013, and published to COATS by March 1, 2013.

MassDEP's reporting system covers all sources with a state operating permit and all sources emitting 5,000 sT or more of CO_2, regardless of whether they have a state permit. RGGI reporting requirements only affect power plants 25 MW or larger. The choice of which facilities would be subject to a supply-side CES would determine which tracking system would be the best choice to support a CES applied to Massachusetts power plants. Few changes to existing MassDEP reporting requirements, if any, would be needed to support a supply-side CES.

Verifying Compliance with a Demand-Side CES

As discussed above, there are four basic designs for a demand-side CES:

- LSEs can be required to meet a "performance standard," to purchase electricity for resale with an average emission rate below a specified level.
- LSEs can be required to meet a "portfolio standard," to purchase a certain percentage of electricity from certain types of plants, defined in the standard.
- LSEs can be prohibited from entering into certain types of contracts or investments.
- LSEs can be required to enter into certain types of contract or investments.

These four types of demand-side CESs require different types of compliance verification systems.

---

[80] New Jersey is a former member; Pennsylvania, Ontario, New Brunswick, and Québec have observer status.

[81] RGGI, Regulated Sources, http://www.rggi.org/design/overview/regulated_sources.

[82] RGGI, Allowance Allocation, http://www.rggi.org/market/co2_auctions.

[83] See http://ampd.epa.gov/ampd/

Regulating LSEs' supply portfolios: Lessons learned in New England

Fundamentally, the approaches available to verify compliance with a demand-side CES portfolio standard are the same as those researched and debated when New England regulators were seeking to develop a system to verify compliance with RPS policies and mandatory electricity labeling or "disclosure" rules. These approaches fell into two basic categories.

1. Regulators could review LSEs electricity contracts. If a supplier wants to use electricity from a specific plant, either in its marketing or to comply with regulations, it must have a contract with that plant. This option was deemed by regulators to be unviable.
2. A system of tradable certificates could be established. A certificate would be created with each MWh of generation. Suppliers would purchase these certificates separately from energy, and they would use the certificates to characterize the fuel mix or emissions of the electricity they sold. Regulators ultimately pursued this option, and created NEPOOL's GIS to allow LSEs to report the attributes—such as generating fuel type and associated emissions—of the electricity they sell.

Reviewing contracts

As noted above, regulators rejected the approach of reviewing LSEs' electricity contracts to verify compliance with RPSs and mandatory disclosure rules. This approach was deemed "unviable," and would be similarly impractical for verifying compliance with a CES.

While examining the "contract tracking" approach for RPS verification, regulators considered at least two different levels of rigor: 1) review all long-term contracts signed by LSEs, or 2) attempt to track the contract path of all electricity sold, including purchases from the real-time wholesale electricity markets. While the first option is daunting, the second is impossible.

Electricity is bought and sold in many different ways, with common transaction types including:

- **Unit contracts:** purchases from a specific generating unit, typically under a longer-term contract
- **System contracts:** purchases from a specific owner's fleet but not from a specific unit, typically under a longer-term contract
- **"Spot market" purchases:** shorter-term purchases from ISO-NE's Day-Ahead or Real-Time markets
- **Wholesale purchases:** purchases from wholesale suppliers to meet load (e.g., investor-owned utilities basic service procurements)

With the exception of electricity purchased through unit contracts, no single generating unit can be associated with electricity purchases. Electricity bought through a system contract could be from the seller's nuclear unit or their gas-fired unit. Electricity bought through the ISO-NE's spot markets cannot be traced to a generating company, let alone a generating unit. Furthermore, it is not uncommon for electricity commitments to be traded many times before the energy is generated and used. Contract tracking would require all traders to track attributes through every transaction. The alternative—tradable certificates—would only require LSEs to purchase attributes from a centralized registry, a much smaller compliance burden.

During the debate over potential tracking systems in New England, at least one system was proposed in which attributes would be tracked through contracts where possible, and attributes of spot market power would be allocated *pro rata* to LSEs. There was strong resistance to this approach for two reasons. First, purchases from the spot markets are a necessity for LSEs to balance unpredictable levels of supply and demand; therefore nearly every supplier would be allocated MWh from these spot markets. This would make it impossible for a supplier to market "100-percent renewable" power or "nuclear free" power unless they also marketed a separate product with nuclear and coal power in it. Second, avoiding spot market and other transactions in which attributes were not trackable would increase costs for LSEs seeking to market "green" products.

Two other reporting requirements have also been raised as a potential basis for contract tracking. The Federal Energy Regulatory Commission (FERC) has historically required utilities to file "Electronic Quarterly Reports," summarizing the contractual terms and conditions for wholesale power sales and transmission services. Similarly, the North American Reliability Council requires entities scheduling interregional power flows to file "e-Tags," reporting the time of the transaction, the physical path of the energy scheduled, including the source and sink control areas, the financial contractual path of the energy and the amount of energy scheduled to flow hourly. These systems, however, would be insufficient to support a CES in a number of ways, with the most obvious problem being that they do not identify specific generating units associated with the transactions.

Ultimately, New England regulators rejected contract tracking and established the NEPOOL GIS system of tradable certificates to support regulations affecting LSEs' portfolios. GIS is currently used to track state RPS and disclosure requirements. The developers of the GIS system, however, were aware that some states were considering regulating the air emissions in LSEs' portfolios. Their intention was to design a system that could support such regulations with minimal revisions.

<u>A system of tradable certificates: NEPOOL GIS</u>

A system in which electricity is separated from its generation attributes can produce the same economic incentives as a system in which the energy and attributes remain linked. With either approach, the goal is to allow market pricing to reflect consumer preferences and regulations. If preferences and regulations require more low-emissions generation, then the market will provide a premium for this generation. When attributes are traded separately from energy, producers receive this premium through the sale of certificates rather than with the sale of electricity. Electricity can still be traded in many complex ways, but LSEs' fuel mixes and emissions are determined by the certificates, and not the electricity, they purchase.

Around the world, many certificate markets are currently operating in the electric power sector. In various regions of the United States, sulfur dioxide (SO_2), nitrogen oxides (NO_X) and CO_2 allowances are traded to achieve compliance with state and federal regulatory programs, and several regions and states—including New England, California, and the Mid-Atlantic—support RPS policies and disclosure requirements with tradable certificates. In these programs, each MWh of generation creates a certificate in a centralized registry, and LSEs purchase these certificates to comply with RPSs and to determine the characteristics of their portfolios for disclosure to consumers. The registry provides a centralized, transparent market for certificates.

The NEPOOL GIS system creates a certificate for each MWh produced in New England, as well as for electricity imported into New England from adjacent control areas (the New York ISO, Quebec, and New Brunswick). Each GIS certificate identifies the following characteristics of the associated MWh:

- Fuel source;
- RPS and Alternative Energy Portfolio Standard (APS)[84] eligibility within each state in New England;
- Emissions (CO_2, NO_X, SO_2, CO, VOCs, mercury, total particulate matter and PM_{10});
- Whether the generator is required to provide EPA with year-round continuous emissions monitoring (CEM) reports;
- Labor characteristics (union or non-union);
- Vintage of generating unit;
- Asset information (generator identification numbers used for ISO-NE and EPA, the asset owner, whether the generator is active or retired, capacity, etc.);
- Total MWh generated by a power plant or conserved by a conservation or load management resource during the calendar month in which the certificate was created;
- Location of generating unit;
- Green-E eligibility;[85]
- Third-party meter reader; and
- RGGI status (whether the unit is subject to RGGI requirements).

The GIS system is used to verify compliance with state RPS policies and New England disclosure requirements. For example, in 2012, Massachusetts LSEs were required to purchase GIS certificates from renewable sources, accepted under the Commonwealth's RPS Class I, sufficient to meet 7 percent of

---

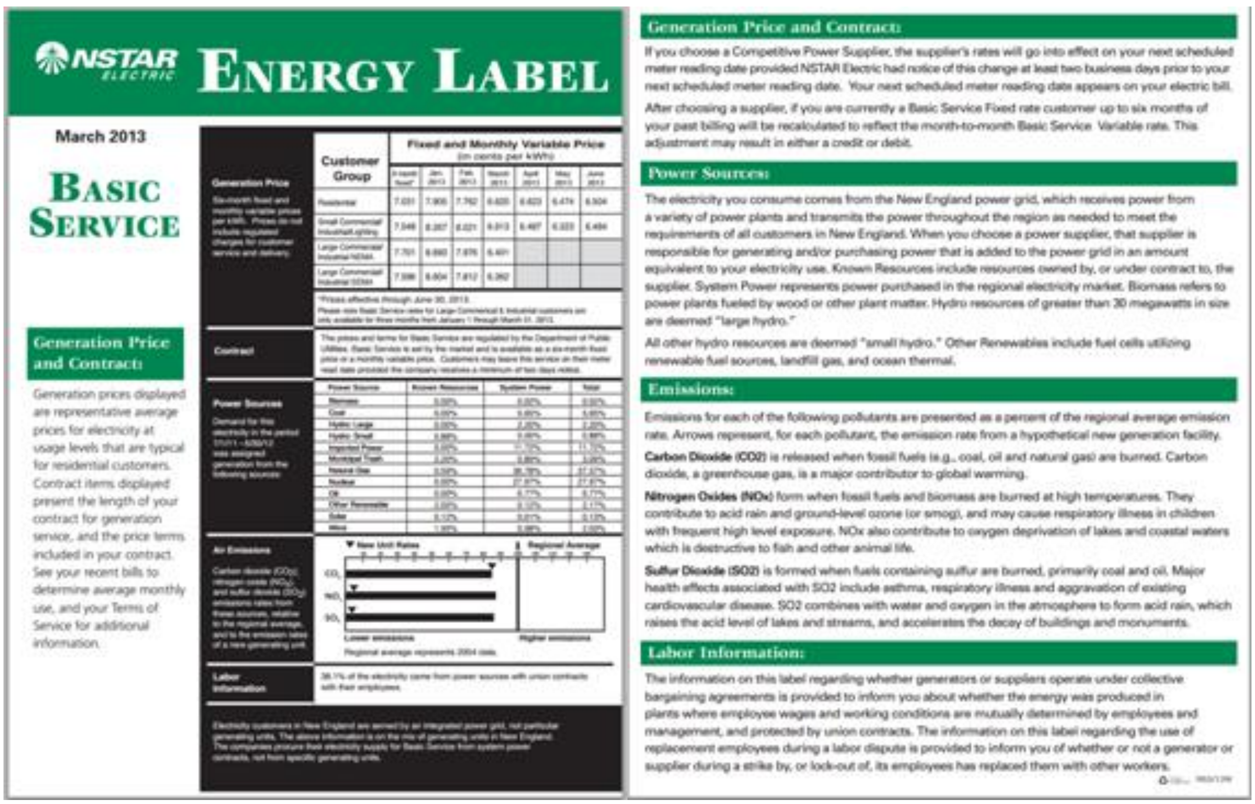
84 The Massachusetts APS requires that electricity suppliers obtain a certain percentage of electricity from alternative energy systems that are not renewable resources. Technologies eligible for the APS include combined heat and power, flywheel storage, coal gasification, and efficient steam technologies.

85 Green-e is an independent certification and verification program for renewable energy and greenhouse gas emission reductions in the retail market. http://www.green-e.org/.

their sales. (Suppliers must submit RPS compliance reports to the Division of Energy Resources by July 1 for the previous calendar year.) Suppliers marketing green products, which include the purchase and retirement of additional RECs or costs associated with contracts with renewable energy producers, purchase additional Class I-eligible certificates to cover these sales.

Massachusetts LSEs also used GIS certificates to support the state's mandatory disclosure requirements, which require electricity suppliers to provide customers with information labels. The labels provide customers with consistently formatted information for use in comparing the attributes of various electricity products. Each label is formatted as a two-page summary that includes the requisite information. The March 2013 disclosure label from NSTAR is shown in Figure 7. Electricity suppliers must provide customers with disclosure labels upon initiation of electricity services, on a quarterly basis thereafter, and upon request.

Figure 7. NSTAR's March 2013 Massachusetts Electricity Disclosure Label



In addition to tracking the attributes of each MWh generated in ISO-NE, GIS also collects information on the electricity retail sales served within the region. Each MWh of electricity sold at retail results in the creation of a "certificate of obligation." NEPOOL GIS ensures that, in each trading period, the total number of generation certificates in the system equals the number of certificates of obligation. Currently, most LSEs only purchase certificates sufficient to meet RPS obligations (if applicable) and to cover any "green" products they are marketing. At the end of each quarterly trading period, the GIS administrator calculates the average characteristics of all certificates <u>not</u> purchased by LSEs. GIS assigns certificates with these "residual average" characteristics to the remainder of LSEs' sales. With this system, an LSE need only purchase certificates to cover its RPS obligations or green products, but its entire energy portfolio is characterized by an emission rate for disclosure requirements.

The GIS administrator also attaches certificates to all electricity imported to or exported from ISO-NE. Information regarding energy imported into ISO-NE is provided by state environmental regulatory agencies and is based on either independently audited data, average emissions for the control area, or data reported to state agencies. Certificates attached to exports do not typically carry environmental attributes. The purchaser of the exported energy is free to purchase other certificates to characterize the energy, but to date this has rarely happened.

For information related to generation, wherever possible, the GIS administrator obtains data from ISO-NE. When relevant and necessary, documentation is provided directly to the GIS Administrator by each generator.

For information related to emissions, certain generators provide the GIS administrator with data for each generation month. The requirements for determining emissions vary by generator depending on the fuel source and whether the generator reports CEM data to EPA. For generators that report emissions to EPA, those reported emissions are simply transferred to the GIS from EPA databases by the GIS administrator. Plants that do not report to EPA provide their own emissions calculations to GIS. For dual-fueled units, the vast majority of units are to report average emissions for the fuel mix they happen to use in a given month, but GIS also allows units to apply for a generator-specific methodology approved by state environmental regulatory agencies to attribute specific emissions to each fuel type. Thus, each certificate issued for most multi-fuel generating units reflects the average emissions for that unit based on the share of each fuel used by the unit during that month.

On both a quarterly and annual basis, the GIS Administrator posts reports for LSEs, state regulators and ISO-NE that contain information on generators' and LSEs' generation and consumption, the types of certificates generated and retired in the applicable period (e.g., renewable certificates, banked certificates, etc.), as well as emissions data.

Using NEPOOL GIS to support a CES

Apart from the issues discussed above, it may be argued that the GIS would be the ideal system to support a demand-side CES in New England. There are, however, currently important challenges regarding the quality of the emissions data in GIS and the transparency of the methods used to calculate emissions. Perhaps the most serious concern is that the emissions data in GIS are not verified by any regulatory agency, and the calculations behind self-reported emissions, and calculations by GIS itself, are not available for review by regulators or the public. Self-reported emissions could be incorrect, and mistakes in data reported to EPA may not be caught after being transferred to GIS. In order for GIS to support a lbs/MWh CES effectively, air regulators would need to be able to review the emissions data reported and the calculations underlying that data. Some changes in data reporting procedures might also be needed to bring the data quality to a level sufficient to support a regulatory program.

When considering a process of reviewing and changing GIS emissions reporting procedures, it is important to remember that Massachusetts is only one of the six states using GIS. Massachusetts regulators do not have the authority to require power plants in other states to report to GIS.

Assuming that the emissions data could be brought up to regulatory standards, GIS could support both performance and portfolio standards applied to LSEs. For a performance standard (based on plants' CO_2 emission rates) no changes besides those discussed above to the GIS would be needed. For a portfolio standard (requiring a percentage of energy from units deemed eligible by the standard), a "Massachusetts CES eligibility" field would need to be added to GIS certificates. This would be a minor adjustment, as certificates already indicate eligibility to meet many different RPS classes in New England.

It would be unfortunate if any New England state were prevented from using GIS to support a CES portfolio standard because it could not be brought up to regulatory standards. All of the other components of an effective certificate system are in place in the GIS system, and getting these components in place was not a trivial undertaking.

Regulation of specific contracts or investments

The existing demand-side CES policies in other jurisdictions prevent LSEs from either investing in, or signing long-term contracts with, high-CO_2 plants. California, Washington, Oregon, and Montana have all enacted standards like this. To enforce this kind of CES effectively, regulators must require all LSEs to report long-term contracts and investments in power plants. (There has been debate over whether the municipal utilities in California, who are not regulated by the Public Utility Commission, are complying with the state's CES.[86]) Currently, the Massachusetts Department of Public Utilities reviews the pricing of supply contracts for the default service retail sales served by the distribution companies, but does not review the contracts of non-utility LSEs. Therefore, new regulations on non-utility LSEs—including competitive suppliers—would be necessary to support this kind of CES in Massachusetts.

MassDEP also requires all LSEs to report the amount of electricity that they sell and the associated greenhouse gas emissions. Specifically, LSEs report to MassDEP the amount of energy sold at retail, and they can also report the number and type of GIS certificates purchased. Any certificates from zero-CO_2 sources can be removed from their greenhouse gas calculations. MassDEP calculates average CO_2 emissions for electricity sold in Massachusetts and provides the emission factor to LSEs for use in calculating their CO_2 emissions.

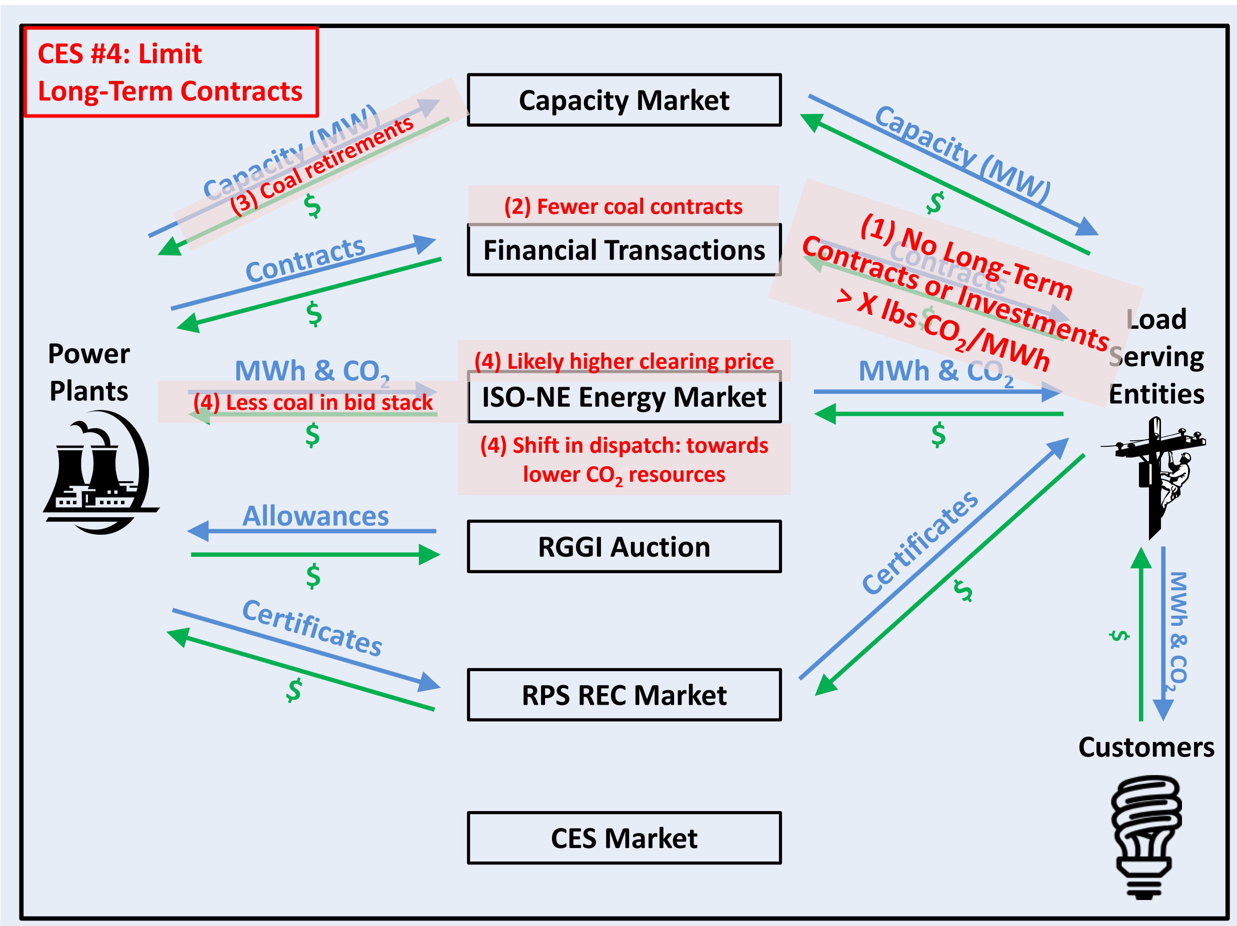
There appear to be ways to circumvent the intent of a CES prohibiting long-term contracts with high-CO_2 plants. For example, a series of short-term contracts could be used rather than a long-term contract, or a contract for power from a company's system could be signed rather than a contract from a specific

[86] See: Joint Petition of the Natural Resources Defense Council and Sierra Club for Initiation of a Rulemaking Regarding California's Emission Performance Standard, November 14, 2011, available at: http://www.energy.ca.gov/emission_standards/2012rulemaking/documents/joint-petiton/.

high-emitting unit. In general, this type of regulation may be more appropriate to implementation in vertically integrated utilities than in restructured markets.

Figure 8 illustrates the dispatch and investment impacts of a CES limiting long-term contracts or investments. Banning LSEs from signing long-term contracts or making investments in resources with emissions rates greater than a given lbs/MWh standard, would limit the introduction of new high-emission resources and result in a greater likelihood of high-emission resource retirements. More high-emission retirements will mean less of these resources in the bid stack and a shift in dispatch towards low-emission resources. Massachusetts distribution companies are already prohibited from entering into long-term contracts with or making investments in any generation,[87] with two exceptions to support clean energy.[88]

Figure 8: CES #4: Limit Long-Term Contracts Schematic



Source: Developed by study authors

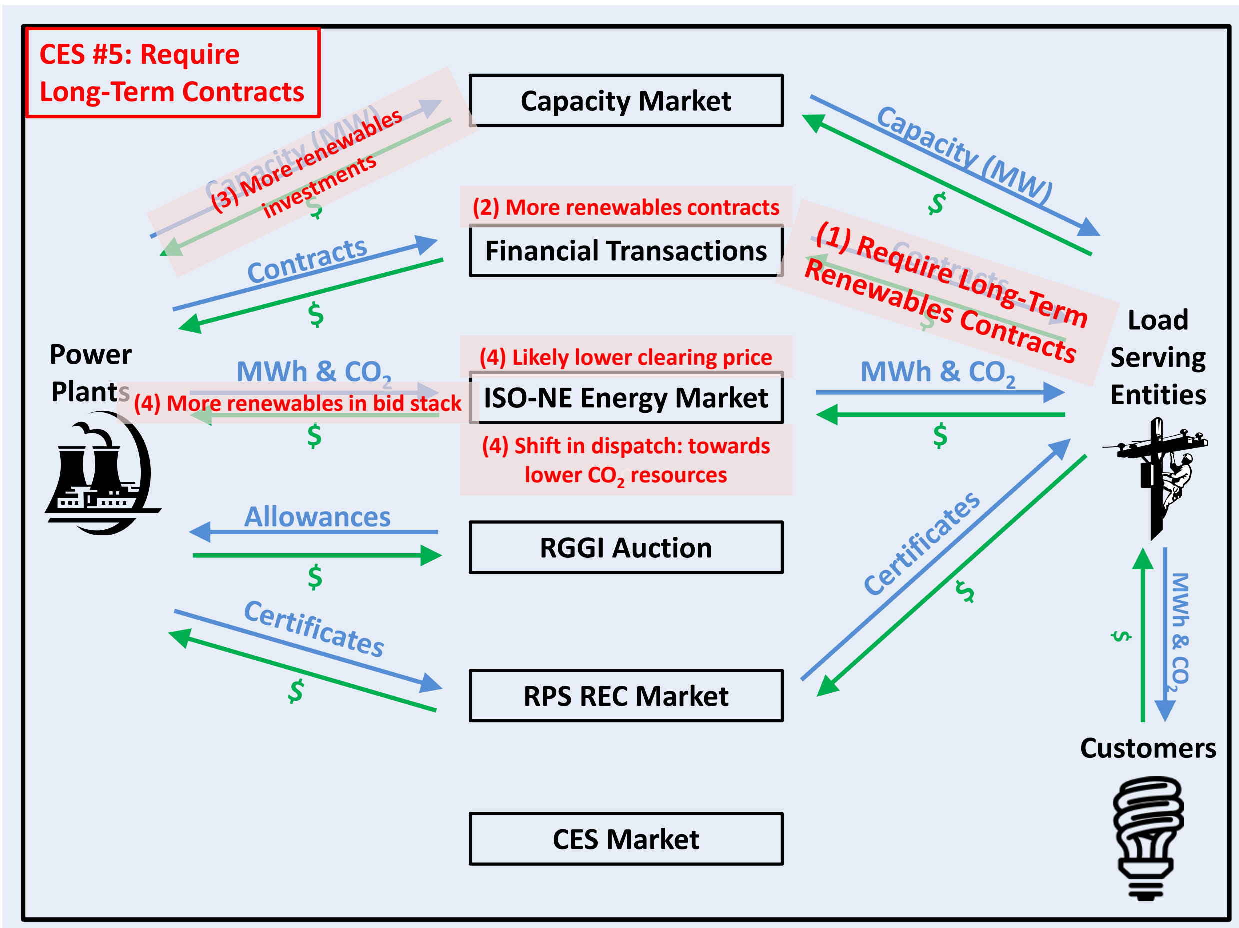
---

[87] MA Restructuring Act, St.2008, c. 169, § 83

[88] MA G.L. c. 164 § 1A(f) and MA 220 C.M.R. 17.00, 21.00.

A CES could also be designed to require LSEs to enter into long-term agreements with renewable or other low-emissions generators. Figure 9 illustrates a CES requirement for long-term contracts with renewables in excess of the existing mandate in Section 83 of the Massachusetts Green Communities Act and the subsequently enacted Section 83A. Requirements for additional long-term contracts with renewable and other low-emission resources would result in more investment in renewables. More low-emission investment would mean more of these resources in the bid stack and a shift in dispatch towards low-emission resources.

Figure 9: CES #5: Require Long-Term Contracts Schematic



Source: Developed by study authors

A CES that required long-term contracts or investments in renewable or low-CO_2 generation—or long-term contracts for certificates from these plants—would have an important benefit. It would provide revenue certainty to generation projects under development, and revenue certainty is critical to the financing of these projects. In comparison, RPS policies based on tradable credits have been criticized in recent years, because they provide a less "bankable" revenue stream. Project developers must seek capital based on forecasted credit prices, while potential lenders and investors prefer to see a long-term contract for at least a portion of the project's output.

Several northeastern states have recognized this weakness of credit-based incentives and chosen different approaches. The state of Connecticut purchases RECs from small (behind the meter) generators under 15-year contracts via periodic solicitations.[89] New York implements its entire RPS program using a procurement model in which the state procures RECs to meet its RPS requirement via periodic solicitations.[90] Rhode Island supports renewable energy with a Feed-In Tariff rather than an RPS, and Massachusetts procures renewable energy from renewable projects via long-term contracts.[91] An independent review of Massachusetts' renewables procurement program found that "long term contracts for energy and RECs are, and will be, necessary for Massachusetts to meet the goals under its RPS…"[92]

Compliance verification could be quite different for CES designs that limit long-term contracts versus those that require these arrangements. Verifying that LSEs have entered into long-term contracts or made investments in certain technologies is relatively straightforward: LSEs would be required to present evidence of these arrangements. Verifying that LSEs have <u>not</u> entered into certain long-term contracts or investments would require LSEs to submit <u>all</u> such contracts or investments for review. A proposal for such a requirement would likely meet with considerable resistance, and the review process could be quite resource intensive.

4.4. Shuffling in Demand-Side Policy Designs

A concern common to both performance and portfolio standards is that CES obligations could be fulfilled from existing resources without any impact on dispatch, investment, or—as a result—emissions. Adjustment can be made to account for or avoid emissions "shuffling" using careful and correct CES design.

Understanding Shuffling

Often called "resource shuffling," LSEs' ability to buy the CES certificates that they need without effecting any change in regional emissions is always a potential concern when a CES-regulated region's retail sales are sourced from a larger supply region. An example may help to illustrate this vulnerability in certificate-based CES: If an LSE with 100,000 MWh sales were required to purchase CES credits equal

---

[89] Christie Bradway, *The LREC/ZREC PROGRAM and RFP Results*, a presentation to the New England Restructuring Roundtable, October 26, 2012, at: http://www.raabassociates.org/main/roundtable.asp?sel=116.

[90] New York State Energy Research and Development Authority, *The New York State Renewable Portfolio Standard Performance Report*, December 2011, at: http://www.nyserda.ny.gov/Publications/Program-Planning-Status-and-Evaluation-Reports/Renewable-Portfolio-Standard-Reports.aspx.

[91] See Section 83 of the Green Communities Act of 2008.

[92] Peregrine Energy Group and New Energy Opportunities, *Study on Long-Term Contracting Under Section 83 of the Green Communities Act*, prepared for the Massachusetts Division of Energy Resources, December 31 2012, at: http://www.mass.gov/eea/docs/doer/pub-info/long-term-contracting-section-83-green-communitiesa-act.pdf.

to 25 percent of its retail sales in 2020—10 percent above and beyond its Massachusetts Class I RPS obligation—it could meet its remaining 10,000-MWh or 10,000-credit CES obligation by purchasing certificates from existing renewables, nuclear, and potentially natural gas throughout the region. As long as there were enough eligible certificates from existing resources to satisfy the CES and other relevant state regulations, there would be no change in regional emissions. There would be a change in Massachusetts emissions from electricity consumption but with no incentive for a change in dispatch or investment, Massachusetts' emission reduction would be exactly matched by an emission increase in the rest of New England; LSEs in Massachusetts would report lower emissions associated with their sales and LSEs in other states would report higher emissions.

In our view, this type of shuffling is unavoidable for an LSE-based performance or portfolio standard in the ISO-NE region. Shuffling will occur and a Massachusetts CES should be designed with that in mind. Therefore, the eligibility terms for a CES must ensure a "binding" CES—a CES stringent enough that it cannot be complied with by simply shuffling certificates for existing generation. Table 16 illustrates the adjustment necessary to account for shuffling for a 2012 example of a Massachusetts-only portfolio-standard CES with nuclear generation and imported electricity excluded. In this example, hydro and other renewables are issued 1.0 credit per MWh, natural gas 0.42 credits per MWh, and nuclear and coal zero credits per MWh. Credits required by other states for their RPS policies are subtracted from total credits to arrive at the 27.2 million credits available for the CES. The available CES credits amount to 50 percent of Massachusetts 54.5 million MWh retail sales for 2012.

Table 16: Shuffling Adjustment Illustration for 2012 Massachusetts-Only CES #3: Portfolio Standard with Nuclear Excluded

		MWh	Avoided Emissions Credits per MWh	Total Avoided Emissions Credits	Credits Required by Other States	Avoided Emissions Credits Available for MA CES
New England Generation						
Gas		49,573,000	0.42	20,820,660		20,820,660
Nuclear		36,116,000	0.00	0		0
Hydro*		6,312,000	1.00	6,312,000		6,312,000
Coal		3,701,000	0.00	0		0
Renewables**		7,988,000	1.00	7,988,000	7,956,000	32,000
Net Imports		12,580,000	0.00	0		0
Total		**116,270,000**				**27,165,000**
MA Electricity Sales		54,540,000				
Binding Threshold	50%					
CES Requirement	60%	32,724,000				
Gap to CES Standard		**5,559,000**				

Source: Developed by study authors

**Hydro includes run-of-river, pondage, and net pumped hydro.*

***Renewables includes wood, refuse, wind, landfill gas, steam, methane, and solar.*

The share of Massachusetts retail sales that can be satisfied by existing credits—given current dispatch and built infrastructure—is called the "binding threshold." In this example, a CES portfolio standard that required LSEs to purchase credits equal to 50 percent of their retail sales or less would not affect dispatch or investment and would not change emissions. With CES credit obligations set at or below the binding threshold, the price of a CES credit would approach zero in the absence of a regulated price floor or an administrative fee built into the CES credit price.

In Table 16, the CES "stringency" is set to 60 percent—that is, Massachusetts LSEs are required to purchase credits equal to 60 percent of their retail sales, or 32.7 million credits in total. At this level of stringency, 5.6 million credits would be needed to comply with CES, in addition to the credits being produced by current dispatch and built infrastructure. In seeking these additional credits, suppliers would bid up the price of low-emission certificates: The more that demand for CES credits outstrips their supply, the higher the CES credit price. These higher certificate prices would reduce the marginal variable cost (and therefore the bid price) of low-emission generators. The order of the bid stack would change such that more low-emissions resources would be dispatched, and the profits to the owners of these resources would grow, providing an incentive for more investment in low-emission resources.

Nuclear Generation

The effectiveness of a demand-side CES depends on its ability to "bind," that is, to require more emissions reductions than are available from current dispatch, current built infrastructure, and regional shuffling. Regardless of whether an LSE-based standard requires adherence to a maximum average emission rate or the purchase of credits equal to a given share of retail sales, including New England's nuclear resources as eligible for meeting an otherwise technology-neutral CES obligations will—in our opinion—make the CES program ineffective: simply put, assigning credits to nuclear resources would drive the binding threshold above Massachusetts retail electricity sales. In a Massachusetts CES portfolio standard not designed to be technology neutral—when credit values for each technology are assigned based on political choices and not in relation to emission rates—it can be said more broadly that some resource type, or group of resource types, would have to be excluded; if both gas and hydro were excluded, for example, it might be possible to include nuclear and still bind.

Table 17 replicates Table 16 with one exception: The example in Table 17 is technology neutral and nuclear is assigned 1.0 credit for each MWh of generation. With nuclear treated as a CES-approved resource, the total number of available credits in this example is 63.3 million—16 percent higher than the Massachusetts retail sales. There is no binding threshold in this example, and not even a 100-percent level of CES stringency—regulating 100-percent of LSEs retail sales—would result in emissions reductions. The inclusion of nuclear in a technology-neutral Massachusetts CES would mean that even the most stringent LSE-driven emission reduction policies would not accomplish any change in dispatch or built infrastructure. The emissions from Massachusetts electricity consumption would not decline.

Table 17: Shuffling Adjustment Illustration for 2012 Massachusetts-Only CES #3: Portfolio Standard with Nuclear Included

		MWh	Avoided Emissions Credits per MWh	Total Avoided Emissions Credits	Credits Required by Other States	Avoided Emissions Credits Available for MA CES
New England Generation						
Gas		49,573,000	0.42	20,820,660		20,820,660
Nuclear		36,116,000	1.00	36,116,000		36,116,000
Hydro*		6,312,000	1.00	6,312,000		6,312,000
Coal		3,701,000	0.00	0		0
Renewables**		7,988,000	1.00	7,988,000	7,956,000	32,000
Net Imports		12,580,000	0.00	0		0
Total		**116,270,000**				**63,281,000**
MA Electricity Sales		54,540,000				
Binding Threshold	N/A					
CES Requirement	60%	32,724,000				
Gap to CES Standard		**N/A**				

Source: Developed by study authors

**Hydro includes run-of-river, pondage, and net pumped hydro.*

***Renewables includes wood, refuse, wind, landfill gas, steam, methane, and solar.*

Disallowing nuclear generation from use in meeting an otherwise technology-neutral Massachusetts CES obligation would be a necessary condition for making the program effective, at least until there are significant nuclear retirements in New England. At the same time, disallowing nuclear generation will also prevent "windfall profits" from CES credits to owners of nuclear facilities. Unlike renewables, lowering the marginal price of nuclear generation will not, in our opinion, result in investment in new nuclear generators in the region. Instead, revenues from a larger gap between nuclear's bid price and the clearing price would be pure profit to plant owners with no investment stimulus effect.

Canadian Renewables

ISO-NE imported a net 13.7 million MWh from Canada in 2012: 0.6 million from New Brunswick and 13.1 million from Hydro-Quebec.[93] Hydro-Quebec reported its generation mix as 98 percent renewables in 2012.[94] Table 18 demonstrates the effects on a Massachusetts CES binding threshold of including existing Canadian hydro as a credit-eligible renewable resource in a portfolio standard. Here net imports are divided into Canadian Net Exports, receiving 0.98 credits per MWh, and New York net exports, receiving 0.0 credits; nuclear generators do not receive credits in this example. Assigning credits to

[93] ISO-NE data, http://www.iso-ne.com/markets/hstdata

[94] Annual Report, http://www.hydroquebec.com/publications/en/annual_report/pdf/annual-report-2012.pdf

existing Canadian hydro raises the number of available credits (excluding nuclear) from 27.2 million to 40.6 million, and the binding threshold for this CES from 50 percent to 74 percent. This means that, with existing Canadian hydro included, Massachusetts LSEs' purchase of credits equal to 74 percent of their retail sales or less would not affect dispatch or investment and would not change emissions. In the example shown in Table 18, the CES requirement is set at 80 percent of Massachusetts electricity sales and the gap to achieving CES compliance is 3 million credits.

Table 18: Shuffling Adjustment Illustration for 2012 Massachusetts-Only CES #3: Portfolio Standard with Canadian Hydro Included and Nuclear Excluded

		MWh	Avoided Emissions Credits per MWh	Total Avoided Emissions Credits	Credits Required by Other States	Avoided Emissions Credits Available for MA CES
New England Generation						
Gas		49,573,000	0.42	20,820,660		20,820,660
Nuclear		36,116,000	0.00	0		0
Hydro*		6,312,000	1.00	6,312,000		6,312,000
Coal		3,701,000	0.00	0		0
Renewables**		7,988,000	1.00	7,988,000	7,956,000	32,000
Canadian Net Imports		13,707,000	0.98	13,432,860		13,432,860
New York Net Exports		-1,127,000	0.00	0		0
Total		**116,270,000**				**40,598,000**
MA Electricity Sales		54,540,000				
Binding Threshold	74%					
CES Requirement	80%	43,632,000				
Gap to CES Standard		**3,034,000**				

Source: Developed by study authors

**Hydro includes run-of-river, pondage, and net pumped hydro.*

***Renewables includes wood, refuse, wind, landfill gas, steam, methane, and solar.*

At present, Hydro-Quebec has 2,468 MW of new hydro-generation under construction (representing 11.4 million MWh of potential generation) and is planning an additional 2,952 MW.[95] The Massachusetts CECP's Clean Energy Imports strategy calls for an additional 1,200 MW of Canadian hydro imports, or approximately 10.5 million new MWh.[96] Adding this generation to the 2012 example in Table 18 would increase available credits to 50.9 million and the binding threshold to 93 percent.

---

[95] Hydro-Quebec, http://hydroforthefuture.com/projets/9/developing-quebec-s-hydropower-potential, http://www.hydroquebec.com/rupert/en/batir/fiche-centrale-eastmain.html, and http://www.hydroquebec.com/publications/en/strategic_plan/pdf/plan-strategique-2009-2013.pdf

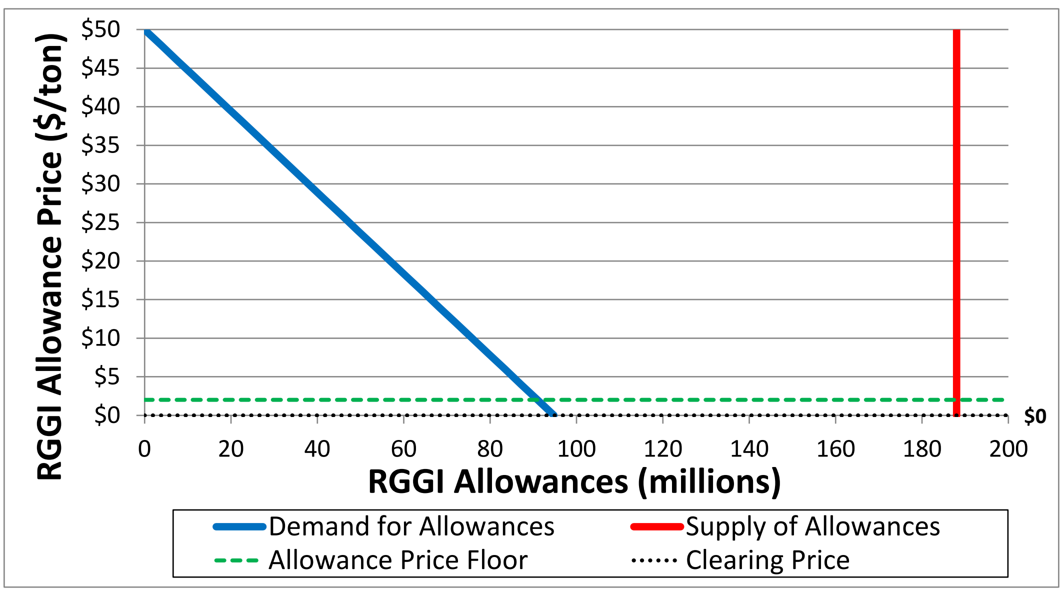
[96] Assumes a 100-percent capacity factor on new transmission lines from Québec or New Brunswick.

Interaction between a Massachusetts CES and RGGI

The RGGI program caps CO_2 emissions from large power plants in nine Northeastern states.[97] The cap is implemented with an allowance system in which affected sources are required to hold one allowance for each ton emitted. Allowances are available at quarterly auctions, and sources also are free to trade allowances among themselves. Affected sources include all fossil fueled plants with a capacity of 25 MW or greater located within a RGGI state. Revenues from RGGI auctions are allocated among the participating states.

Because natural gas prices fell precipitously shortly after the inauguration of RGGI, the RGGI cap has, through 2013, not been binding. As illustrated in Figure 10, the cap for each year from 2009 to 2011 was 188 million sT of CO_2 (shown in red) and the recent number of allowances sold—91 million sT—is determined not by the intersection of supply and demand, but by the intersection of the (blue) demand curve with the (green) allowance price floor of $1.93. Beginning in 2014, the RGGI cap will be lowered to 91 million sT of CO_2, falling by 2.5 percent in each subsequent year, with a "cost containment reserve" that releases an addition 10 million allowances if a $4 price (rising in later years) is exceeded.

Figure 10: RGGI 2011 Supply and Recent Demand Illustration

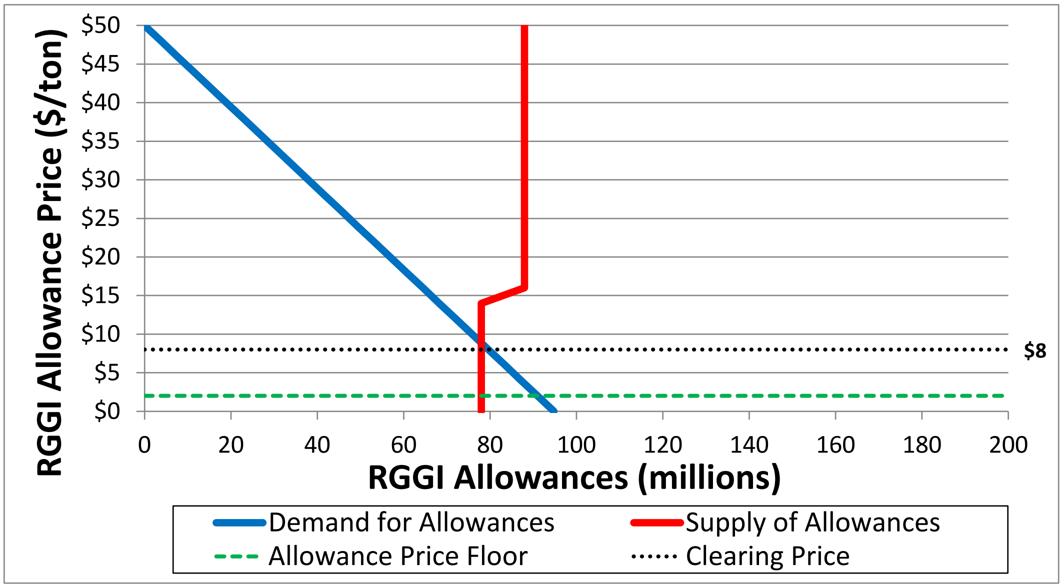


In all of the graphs that follow, the supply curve is based on the actual allowance cap for the year shown under current RGGI policy, while the slope of the demand curve is entirely illustrative and not based on data. If demand remains at recent levels, the RGGI cap would be binding by 2015.

As shown in Figure 11, by 2020 the price per allowance would be approximately $8.

97 These states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

Figure 11: RGGI 2020 Supply and 2013 Demand Illustration



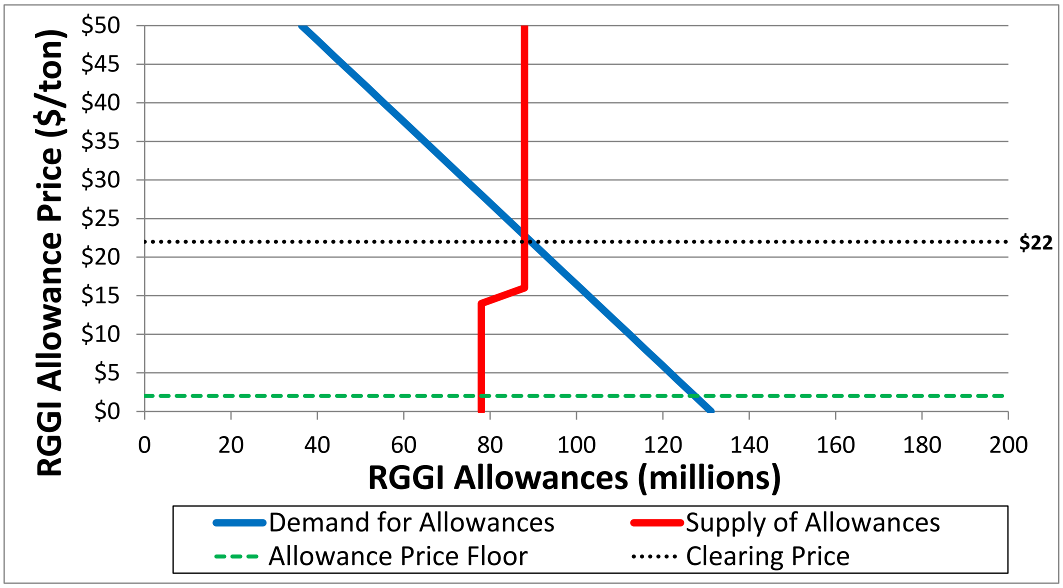
Demand, however, is not expected to stay constant. The demand curve may shift outward (to the right, representing demand for more allowances at every price) due to:

- **Higher retail sales:** The RGGI region's electricity consumption may increase if population growth outstrips energy efficiency measures or if other forms of energy use shift into electricity (for example, electrification of the transportation sector). Higher retail sales would result in a shift in dispatch to accommodate higher generation and, in the longer run, investment in new gas and other generation resources.
- **Nuclear retirements:** If nuclear (or, although far less likely to occur, renewable resources) are retired, dispatch of existing gas and coal generators would increase as would the incentive for building new gas and other generation resources. Vermont Yankee and Indian Point are both credible retirement risks by 2020.[98]
- **Reduced thermal efficiency:** Certain EPA regulated emission controls have the potential to reduce the thermal efficiency of existing coal plants such that generation of the same MWh would result in more tons of CO_2 than before. In this example, dispatch and investment stay constant, but the demand for allowances rises nonetheless.
- **Rising gas prices:** If the price of fuels for lower-emission generation resources were to rise in relation to those of higher-emission resources enough to shift dispatch, MWh of generation would stay constant but there would be more demand for allowances.

[98] Indeed, on August 27, 2013 Entergy announce the 2014 retirement of Vermont Yankee, although this information was released too late to be included in the modeling described in this report. Entergy Press Release, August 27, 2013, "Entergy to Close, Decommission Vermont Yankee," http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769.

Figure 12 shows the 2020 supply of RGGI allowances together with an illustrative shift outward (right) in the demand curve. In the hypothetical example shown, demand crosses supply at $22 per ton, above the 2018 trigger price for the cost containment reserve. This shift in the demand curve results in an increase in RGGI region emissions from 78 to 88 million tons.

Figure 12: RGGI 2020 Supply and Higher Demand Illustration



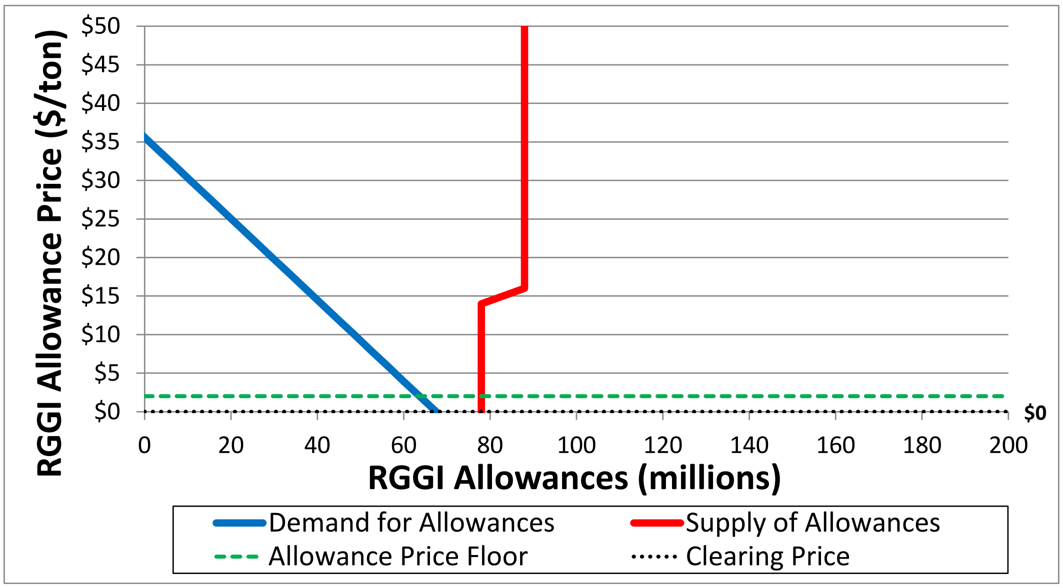
The demand curve also may shift inward (to the left, representing less demand for allowances at every price) due to:

- **Lower retail sales:** The RGGI region's electricity consumption may decrease if energy efficiency measures outstrip population growth. Lower retail sales would result in a shift in dispatch to reduce generation and, in the longer run, would likely decrease incentives for investing in generation resources.
- **New renewables:** Investment in new renewables (or, far less likely, new nuclear) would shift dispatch away from gas and coal, reducing demand for allowances.
- **Coal retirements:** Coal retirements due to EPA regulations will result in additional dispatch of existing gas generators and greater incentives for building new gas and other generation resources. AESC 2013 projects retirement of all New England coal plants but Merrimack 1 and 2 by 2020.
- **Better thermal efficiency:** Maintenance and incremental technology improvements could increase the thermal efficiency of existing coal and gas plants such that generation of the same MWh would result in fewer tons of CO_2 than before. Dispatch and investment would stay constant, but the demand for allowances would fall.

- **Falling gas prices:** If the price of fuels for lower-emission generation resources were to fall in relation to those of higher-emission resources enough to shift dispatch, MWh of generation would stay constant but there would be less demand for allowances.

Figure 13 shows the 2020 supply of RGGI allowances together with an illustrative shift inward (left) in the demand curve (compared to the base case in Figure 11). In the hypothetical example shown, allowances are sold at the price floor because supply and demand fail to intersect. This shift in the demand curve results in a decrease in RGGI region emissions from 82 to 64 million tons.

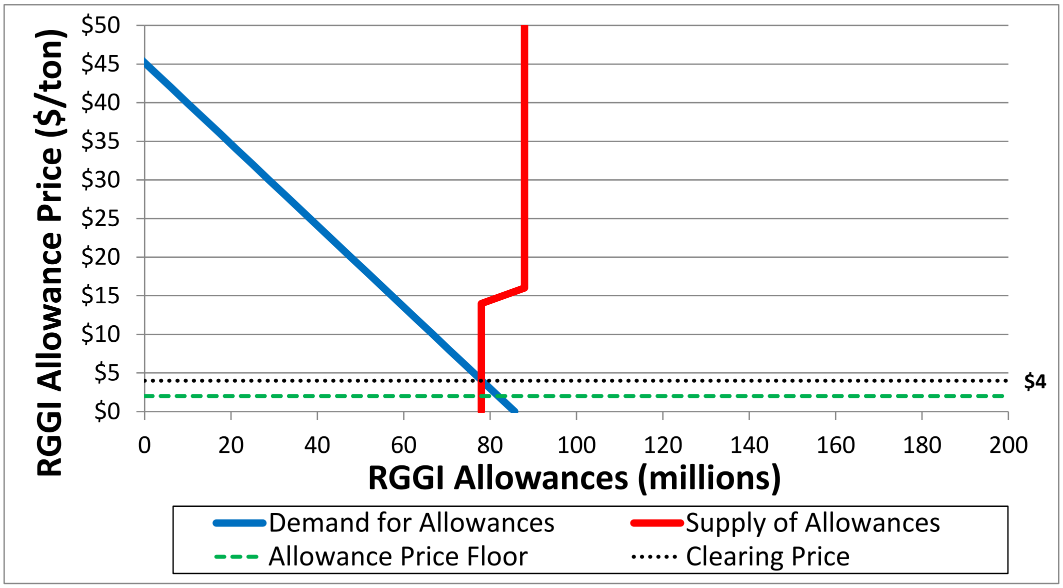
Figure 13: RGGI 2020 Supply and Lower Demand Illustration



Massachusetts CES and RGGI Shuffling

One concern with the effectiveness of certain Massachusetts CES designs is that shuffling of RGGI allowances would result in a corresponding increase of RGGI-region emissions that displaced some or all of the emission reductions from Massachusetts electricity consumption. In this scenario, compliance with the CES would lower the marginal price of lower-emission electricity or raise the marginal price of higher-emissions electricity. If these price shifts were sufficiently large to change dispatch—that is, if the change in a resource's price is large enough that it caused the resource to swap places in the bid stack with the next higher or lower resource (and that resource had a significantly different emission rate)—then the demand curve for allowances would shift to the left as shown in Figure 14 (compared to the base case in Figure 11) with no corresponding decrease in regional emissions even though Massachusetts electricity consumption emissions decline.

Figure 14: RGGI 2020 Supply and Demand Illustration of Shuffling



But the shuffling effect—with regional emission increases balancing out Massachusetts emission decreases—is far from inevitable. That is, demand for RGGI allowances will not automatically rise to assure the purchase of all allowances under the cap: Because the original RGGI cap was set too high, the number of allowances sold was consistently determined by price floor, and not the intersection of supply and demand; in the historical period, demand for RGGI allowances did not automatically rise to meet the cap. RGGI shuffling might eliminate some of the CO_2 reduction benefits of a Massachusetts CES, but there are several mitigating factors. These include:

- Annual reductions to the RGGI targets.
- Market inefficiencies: The RGGI market does not respond perfectly to a reduced demand for certificates.
- The potential for administrators to make the RGGI caps more stringent.

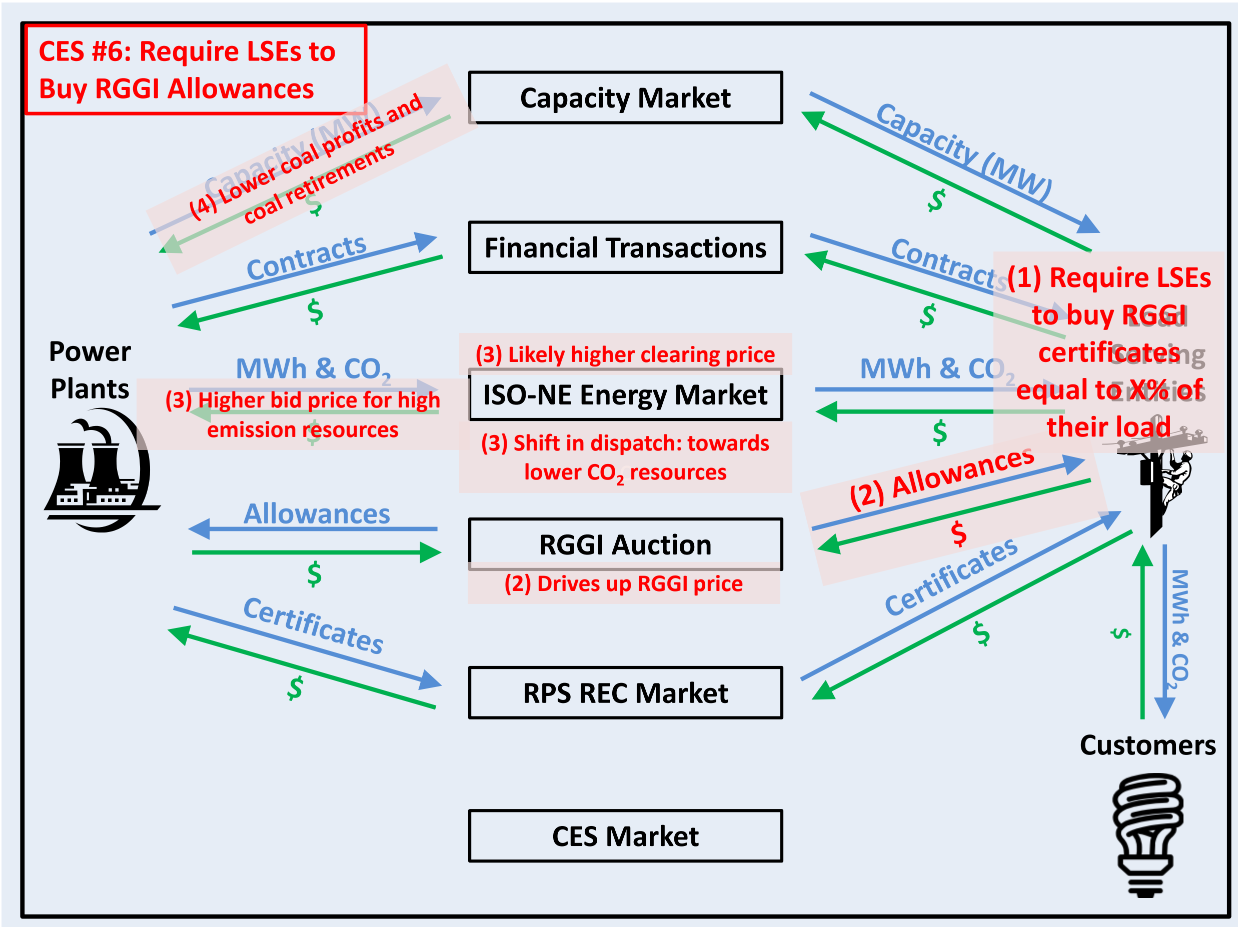
A Massachusetts CES would likely shift the demand curve for RGGI allowances inward (left); whether or not this shift, together with all other changes in supply and demand, would result in regional emissions staying steady remains to be seen. It is important to recall that the ability of Massachusetts LSEs to affect allowance prices and shift regional dispatch is diluted by the greater RGGI pool; Massachusetts retail sales are only approximately 15 percent of total RGGI retail sales. In addition, the elasticity of RGGI allowance demand—how much demand for allowances would change at higher prices—is largely unknown since prices have not exceeded the floor except in the first two and the most recent auctions, and this uncertainty, too, makes the assumption of automatic, "perfect" RGGI shuffling difficult to support.

The RGGI cap and potential Massachusetts CES (or other state emission reduction policies) should not be thought of as substitutes, each competing with the other. Rather, state emission reduction policies (energy efficiency, RPS, portfolio and performance standards, limitations on long-term electricity contracts) are all ways in which the RGGI cap is achieved—these measures work together as complements. State emission reduction policies need to keep up with the annual 2.5 percent reduction in the RGGI cap. If they fall behind the cap, there is a potential for a regional emissions increase if the cost compliance reserve is triggered. In the end, a Massachusetts CES would have two important, but still separate goals: 1) to reduce emissions from Massachusetts electricity consumption—a goal that could be met by a binding CES regardless of shuffling—and 2) to reduce regional emissions—a goal that might be hampered or possibly even eliminated in the absence of some or all of the mitigating factors listed above.

A RGGI-based Massachusetts CES design

There is a final potential Massachusetts CES design that would eliminate any chance of RGGI allowance shuffling: a requirement that Massachusetts LSEs purchase RGGI allowances equal to a given share of their retail sales. Figure 15 illustrates this design. LSEs would purchase and retire RGGI allowances, driving up both the RGGI price and the bid price for higher emission resources. The result would be a shift in dispatch towards lower-emission resources, lower coal and gas profits, and more coal retirements. This CES design would only be effective if—excluding Massachusetts CES purchases—the RGGI allowance cap were binding; reducing the RGGI cap would have no effect on regional emissions if the actual number of allowances sold were determined by the price floor and not the intersection of supply and demand.

Figure 15: CES #6: Require LSEs to Buy RGGI Allowances Schematic



Source: Developed by study authors

While an elegant, simple solution to effective CES design, requiring Massachusetts LSEs to retire RGGI allowances may lack political viability. Massachusetts policy makers would need to consider carefully any policy with such a direct impact on the RGGI price, and political will would need to be gauged before seriously exploring such a policy.

4.5. Narrowing the Massachusetts CES Design Options

Synapse reviewed a range of potential CES designs, and discusses their positive and negative qualities. Table 19 summarizes these findings. Based on the direction provided by MassCEC and the Agencies, power-plant-based performance standards, limitations or requirements of long-term contracts, and LSE purchases of RGGI allowances all appear to either be politically infeasible at this time or overlap with existing policies. Our qualitative analysis of CES designs identified several disadvantages of implementing an LSE-based performance standard in Massachusetts; this type of CES: 1) has not been proposed or established in any other jurisdiction, 2) comes with significant administrative and design hurdles, and 3) is not necessarily more "technology neutral" than a portfolio standard.

Based upon the analysis presented here and the direction provided by MassCEC and the Agencies, we have focused the CES modeling analysis on the LSE portfolio standard design. The CES Policy Model described in Section 5 was designed to demonstrate the effect on emissions reductions and program costs of allowing particular resources—nuclear, large scale hydro, etc.—to be excluded from an otherwise technology neutral LSE portfolio standard for Massachusetts.

Table 19: Pros and Cons of CES Designs

CEPS Design	Description	In Other Jurisdictions	Analysis
#1: Set Power Plant Emission Standards	Standard applied to power plants requiring them to maintain emission rates below a given level.	U.S. EPA Greenhouse Gas NSPS for Power Plants, United Kingdom, Canada, New York	These standards generally affect new or expanded plants or (in one case) very old plants. Because these standards are applied to generators, there is no need for a system that tracks generation to LSEs. There is also no risk of "shuffling."
#2: Set an LSE Performance Standard	Standard applied to LSEs requiring them to meet an average emission rate for their load.	none	To our knowledge, no jurisdiction has adopted a CES in which: LSEs are required to hold a credit for every MWh sold; and each eligible plant produces credits with a unique CO_2 emission rate.
#3: Set an LSE Portfolio Standard	Standard applied to LSEs requiring them to cover some portion of their sales with credits from specific resources.	Bingaman Clean Energy Standard Act, Obama Clean Energy Standard Proposal	These proposals would require a new system of tradable credits; eligible plants would generate a credit with each MWh produced. (Some technologies may generate a partial credit with each MWh.) As with RPS policies, LSEs would be required to hold credits covering a defined percentage of their total sales.
#4: Limit Long-Term Contracts	Standard applied to LSEs prohibiting them from investing in, or signing long-term contracts with, CO_2 intensive sources	California, Washington, Oregon, and Montana	These standards seek to reduce demand for electricity from CO_2 intensive plants, and are implemented through review of, or mandatory reporting of, an LSE's equity holdings and long-term contracts. There is no need to track all electricity in the region to an LSE.
#5: Require Long-Term Contracts	Standard applied to LSEs requiring them to enter into long-term agreements with low-emissions generators.	In CT, RI, and NY the state signs long-term contracts with renewables for RECs, or energy and RECs.	The standard would need to be expressed as a percentage of load and applied to all LSEs to avoid disadvantaging certain LSEs. MA is currently the only state in New England that requires certain LSEs to enter into long-term contracts with renewables.
#6: Require LSEs to Buy RGGI Allowances	Standard applied to LSEs requiring them to purchase and retire RGGI allowances.	none	While an elegant, simple solution to effective CES design, requiring Massachusetts LSEs to retire RGGI allowances may lack political viability.

5. QUANTITATIVE ANALYSIS: THE CES POLICY MODEL

Synapse developed the CES Policy Model to estimate the projected emission, resource mix, and cost impacts of the implementation of a CES policy—designed as an LSE portfolio standard—in some portion of New England. This new portfolio standard would require LSEs to purchases Clean Energy Certificates (CECs) equal to a model-user-determined share of their retail sales. The CES Policy Model projects generation by resource for 2015, 2020, 2030, 2040 and 2050 for a static Reference Case—representing the CECP Electrification Scenario, excluding the Clean Energy Imports strategy—and a dynamic CES Policy Case, which allows for several user choices regarding policy implementation.

Because changes to Massachusetts and New England emissions are a key output to the modeling exercise, it was necessary to identify a greenhouse gas emissions accounting methodology that would accurately estimate the effects of CECP policies. The following sub-section describes the process of developing this inventory methodology.

5.1. Greenhouse Gas Inventory Methods and the CECP

The current official Massachusetts greenhouse gas inventory method does not award the Commonwealth with the full emission reduction benefits of a CES. This section describes a new inventory method for Massachusetts that would not only allow for accurate accounting of CES emission reductions but would also assign emission reductions from RECs to the state in which they are purchased. In addition, we present a related process for representing the proposed inventory method in the CES Policy Model designed by Synapse for MassCEC and the Agencies. The proposed inventory method hinges on defining the impact of the CES policy on the Massachusetts greenhouse gas emissions inventory as the emission *reduction* that it causes. And not, instead, counting up the emissions associated with CECs.

The proposed inventory method hinges on defining the impact of the CES policy on the Massachusetts greenhouse gas emissions inventory as the emission reduction that it causes.

Current Massachusetts Inventory Method

The Massachusetts greenhouse gas inventory is required to estimate electric-sector emissions on a "consumption" rather than a "geographic" or "production" basis.[99] According to the GWSA, Massachusetts emissions are:

[99] Geographic- or production-based electric-sector inventory methods assign states the emissions associated with all electricity generated within their boundaries, regardless of electricity imports and exports.

> "Statewide greenhouse gas emissions", the total annual emissions of greenhouse gases in the commonwealth, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in the commonwealth, accounting for transmission and distribution line losses, whether the electricity is generated in the commonwealth or imported; provided, however, that statewide greenhouse gas emissions shall be expressed in tons of carbon dioxide equivalents.[100]

The Commonwealth's Department of Environmental Protection acknowledges that there are multiple defensible accounting methods for the greenhouse gas emissions resulting from electricity consumption. The *2006-2008 Massachusetts Greenhouse Gas Emissions Inventory*[101] (the "Inventory") explains that:

> There are a variety of methods that can be used to estimate the emissions due to Massachusetts' consumption of electricity, including emissions associated with electricity generated out-of-state. MassDEP believes it is appropriate to consider GHG emissions associated with electricity consumption in regional and more state-specific contexts, since, due to the linked, regional nature of the New England electric grid, electricity generated in a state is not necessarily consumed in that state, even if that state is a net importer of electricity.

The Inventory notes that two such methods were explored in its preparation, one in which "all electricity generated in Massachusetts is used in Massachusetts" and another that involves "determining the fraction of New England electricity (in MWh) that is consumed in Massachusetts."[102] These methods are described in the Inventory as follows:

Massachusetts-based (Massachusetts Generation Plus Imports): "[E]lectric sector emissions in this approach are based on emissions from Massachusetts power plants plus a portion of emissions from power plants in the other New England states that generate more electricity than they use in a given year and in the adjacent control areas (New York, New Brunswick, Quebec) in years that New England received net imports of electricity from those control areas."[103]

Regional-based (Regional Power Pool): "[E]lectric sector emissions in this approach are based on the total New England GHG emissions from electricity generation plus GHG emissions associated with electricity imported from the adjacent control areas (New York, New Brunswick, Quebec) in years that

---

[100] MGL Chapter 21N, Section 1. https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter298

[101] *Final 2006-2008 Massachusetts Gas Emissions Inventory,* July 2012, Department of Environmental Protection, p.8, http://www.mass.gov/eea/docs/dep/air/climate/ghg08inf.pdf

[102] Ibid, p.9

[103] Ibid, p.9

New England received net imports of electricity from those control areas; this total was multiplied by the ratio of Massachusetts to New England electricity consumption."[104]

For purposes of determining progress on greenhouse gas reduction from 1990, Massachusetts has chosen to use the Massachusetts-based method, but for reference reports the results of both methods in published inventories.[105]

The Dilemma Regarding the Current Inventory Method

Neither of the methods presented in the Inventory fully accounts for emission reductions resulting from the full suite of electric-sector policies described in the CECP, which discusses six policies related to electric generation and consumption:

1. **All Cost-Effective Energy Efficiency:** The effect of this policy (as it relates to the electric sector) is to reduce customers' demand for electricity. This policy's full impact is captured by the existing inventory methods.

2. **Massachusetts RPS:** Massachusetts electricity suppliers are required to purchase RECs equal to a rising percentage of their retail sales. Suppliers' REC purchases subsidize the construction of new renewable energy resources. A critical feature of this program is that suppliers are purchasing a certain attribute of a given MWh of generation (its status as "renewable") but not the energy associated with that attribute. Massachusetts' purchase of out-of state RECs—and, arguably, its responsibility for this low-carbon generation—is not fully captured by existing inventory methods; nor, it should be noted, is any other states' purchase of Massachusetts-generated RECs.

3. **RGGI:** Massachusetts generators are required to purchase a RGGI certificate for each ton of carbon dioxide that they emit. Rising RGGI certificate prices will impact Massachusetts emissions by discouraging the dispatch of high-emission generation resources located in Massachusetts and in the remainder of New England. These changes to emissions would be captured by the existing inventory methods.

4. **More Stringent EPA Power Plant Rules:** The implementation of EPA's more stringent power plant rules is expected to result in the retirement of certain generators in New England. The resulting changes in emissions would be captured by the existing inventory methods.

5. **Clean Energy Imports:** The CECP calls for increased imports of low-carbon energy from Hydro-Quebec in the form of a new 1,200 MW transmission line. Regardless of Massachusetts' contribution to investments for this transmission line, or other incentives provided towards its construction, the existing inventory methods would not

---

104 Ibid, p.9-10

105 Final 2006-2008 Massachusetts Gas Emissions Inventory, July 2012, Department of Environmental Protection, p.8, http://www.mass.gov/eea/docs/dep/air/climate/ghg08inf.pdf; and ghginv9012.xls, www.mass.gov/eea/docs/dep/air/climate/ghginv9012.xls

award Massachusetts the full emission reduction associated with displacing existing higher-carbon generation resources with lower-carbon Quebec imports. The Massachusetts-based inventory method would assign the Commonwealth a share of Quebec imports equal to its total share of combined intra- and extra-New England imports. In the Regional-based inventory method, the average New England emissions rate would fall as a result of this policy, awarding all six states with a share of this emission reduction benefit.

6. **"Clean Energy Performance Standard" (CES):** The CES, as described in the CECP, could refer to a wide assortment of portfolio and performance standard policy designs. In the course of Synapse's analysis of CES options, this range of possible policy designs has—in consultation with Massachusetts agencies—been narrowed to a portfolio standard for suppliers—in essence, a technology neutral version of the RPS. Massachusetts purchase of out-of-state "Clean Energy Certificates" (CECs) would not be fully captured by existing inventory methods.

The emission reductions from three CECP electric-sector policies—RPS, Clean Energy Imports, and CES—would not be fully reflected in the current Massachusetts inventory methods and, therefore, would be more difficult to claim as contributions to meeting Massachusetts GWSA targets of 25 percent reductions from 1990 emissions by 2020 and 80 percent by 2050. Together the RPS and Clean Energy Imports strategies account for 6.5 percentage points of total 2020 Massachusetts reductions as estimated in the CECP—or about a quarter of required 2020 reductions for all sectors combined.[106]

An Appropriate Inventory Method for GWSA Compliance

Counting CECP electric-sector policies towards GWSA compliance will require an updated inventory method. The following method is proposed for this purpose:

Step 1: Begin with the Massachusetts-based method as described above. While the Regional-based inventory method is a better representation of the actual flow of power necessary to serve Massachusetts consumers, the Massachusetts-based method has a clear policy advantage: The assumption that Massachusetts electric-sector emissions come first from Massachusetts-based generation places the main source of emissions within the Commonwealth's legal jurisdiction: Massachusetts can regulate power plants located within its borders. In effect, the Massachusetts-based inventory method may afford more control over the sources of emissions.

Step 2: Adjust Massachusetts-based emissions to reflect New England states' RPS purchases. Massachusetts generation would be reduced by the MWh of electricity associated with RECs generated in Massachusetts but purchased out of state. In addition, MWh associated with all six states' REC purchases would be removed from the pool of intra-New England imports available to Massachusetts.

[106] The CECP does not estimate emission reductions from the CES.

Whether these changes would increase or decrease MA emissions would depend on the relative emissions, quantity, and direction of transfer of RECs.

Step 3: Adjust emissions to reflect emission reductions from the RPS and Clean Energy Imports policies. Each MWh of low-carbon electricity associated with a Massachusetts REC purchase or with Massachusetts' investment in new Hydro-Quebec imports (from import incentives other than CES)[107] would be assumed to replace a MWh of electricity consumed in Massachusetts that has the average emission rate implied by the adjusted Massachusetts-based method from Step 2.

Step 4: Adjust emissions to reflect emission reductions from the CES policy. The CES policy design explored in most detail by Synapse is technology neutral (or, alternatively, technology neutral with the exception of excluding nuclear generation from receiving CECs). CECs, therefore, are assigned to all eligible generation resources and—depending on the lbs/MWh threshold set for assigning certificate values—may include resources with emission rates high enough to raise rather than lower Massachusetts emissions. The goal of the CES policy, of course, is to reduce Massachusetts emissions from electricity consumption. In this spirit, each MWh of electricity associated with a Massachusetts CEC purchase *from a resource with an emission rate equal to or lower than that of the average Massachusetts-based electricity consumption emissions rate in the first year of CES implementation* would be assumed to replace a MWh of electricity consumed in Massachusetts that has the average emission rate implied by the adjusted Massachusetts-based method from Step 3.

Note that GWSA's requirement to include out-of-state emissions associated with the electricity imported to Massachusetts has always meant that careful consideration must be made in determining total New England greenhouse gas electric-sector emissions. To avoid double counting in a New England-wide electric-sector greenhouse gas emissions exercise, one would include only the in-state Massachusetts electric-sector emissions, excluding the emissions associated with electricity imported to Massachusetts.

Implementing the Proposed Approach in Synapse's CES Policy Model

In the CES Policy Model, Massachusetts emissions cannot be modeled as following the Massachusetts-based inventory method because generation resources in the model are not designated by state. Instead, the CES Policy Model uses: the Regional-based method with the adjustments described as "Step 2" in the previous section; and emission reductions from Massachusetts REC and CEC purchases assumed to replace MWh of electricity consumed in Massachusetts at the average emission rate. Counting the true impact of the CES policy towards GWSA compliance in the CES Policy Model is accomplished as follows:

[107] For an example of a potential Clean Energy Import strategy unrelated to CES see http://www.mass.gov/eea/pr-2013/ne-hydro.html.

Step 1: Assign Massachusetts all emissions associated with its REC purchases.

Step 2: Adjust generation and emissions of New England to exclude REC purchases from all six states.

Step 3: Divide generation and emissions of the New England residual pool into CES-eligible and CES-ineligible portions using the assumption that only CEC purchases that lower Massachusetts emissions are included in the CES-eligible pool. The model would establish the average Massachusetts-based electricity consumption emission rate in 2015. CES-eligible resources with emission rates equal to or lower than this average would be included in the CES-eligible pool for modeling purposes. CES eligible resources with emission rates higher than this average would be included in the CES-ineligible pool, again, for the purpose of estimating emissions within the CES Policy Model only. This change in inventory would not represent a change in the assignment of CECs in the policy itself.

Step 4: Satisfy Massachusetts demand for electricity (less RPS purchases) first from the CES-eligible pool and second—if necessary—from the CES-ineligible pool. This accounting method provides the best possible estimation of the emissions implications of implementation of an LSE portfolio standard in the CES Policy Model.

5.2. Reference Case

The CES Reference Case is modeled as follows:

Step #1: Retail Sales

Retail sales for Connecticut, Maine, New Hampshire, Rhode Island, and Vermont for 2015 and 2020 are taken from CELT-2013 with passive demand response (PDR); 2030, 2040 and 2050 sales for these states are extrapolated using the 2015-2020 rate of change.

Massachusetts retail supplier sales[108] for 2015 and 2020 are taken from CELT-2013 with PDR. Massachusetts 2050 sales are taken from the CECP Electrification Scenario; 2030 and 2040 sales are linearly interpolated.

[108] Sales by retail supplier are adjusted for line losses and, therefore, functionally equivalent to generation.

Table 20. Reference and Policy Case Retail Sales Forecast (GWh)

State	2015	2020	2030	2040	2050
CT	33,034	34,366	35,129	36,787	38,041
MA	61,207	61,896	63,385	64,234	64,440
ME	11,503	11,584	11,656	11,742	11,822
NH	12,325	12,821	13,319	13,866	14,419
RI	8,260	8,047	7,789	7,608	7,396
VT	6,090	5,812	5,493	5,273	5,022
Total	**132,419**	**134,525**	**136,769**	**139,510**	**141,141**

Step #2: Match Generation to Load

The CES model next matches generation to load using resource mix shares from the 2015 and 2020 AESC 2013 RGGI Case for model years 2015 and 2020, and the 2028 AESC 2013 RGGI Case for model years 2030, 2040 and 2050, with the following adjustments to years 2030 and later:

- Resources expected to retire are removed from the mix.
- Current statutes regarding future RPS and APS requirements are met.
- The mix of new zero-carbon resources was selected to take account of modeling results from AESC 2013 for 2028, New England renewables potential, and expectations regarding the future delivered price of renewables (see discussion below).

Table 21. Reference Case Resource Mix (GWh)

Resource	2015	2020	2030	2040	2050
Hydro	8,086	8,349	8,950	8,950	8,950
Coal	8,903	4,609	0	0	0
Nuclear	32,331	29,647	29,647	9,028	0
CHP	5,268	5,363	5,153	5,153	5,153
Other	2,780	2,812	2,842	2,710	2,740
Import	9,443	9,443	9,443	9,443	9,443
Oil	343	72	2	0	0
Bio	3,586	5,110	5,300	5,429	5,448
NG	55,056	55,538	56,438	73,762	78,428
Solar	2,217	5,305	8,297	11,647	14,997
Wind	4,407	8,278	10,696	13,389	15,982
Total	**132,419**	**134,525**	**136,769**	**139,510**	**141,141**

Step #3: Reference Case Outputs

In addition to the resource mix, the CES Policy Model estimates the following outputs (as shown in Table 22):

- New England CO_2 electricity-sector emissions (including generation and imports) based on the generation detailed above and emission rates derived from AESC 2013 data.
- Massachusetts CO_2 electricity-sector emissions based on the methodology described above.
- Customer rates and costs by category of rate payer.

Table 22. Reference Case Emission and Cost Outputs

Emissions

		2015	2020	2030	2040	2050
New England CO_2 Emissions (including imports)	1000 sT	42,117	37,738	33,373	42,516	45,031
Massachusetts Consumption CO_2 Emissions	1000 sT	19,985	18,348	15,545	18,198	17,554
Massachusetts Consumption CO_2 Emissions Rate	sT/MWh	0.327	0.296	0.245	0.283	0.272

New England Costs

		2015	2020	2030	2040	2050
Supply	GWh	132,419	134,525	136,769	139,510	141,141
Fuel Costs	M$	3,683	4,223	4,678	7,014	8,984
CO_2 Costs	M$	222	398	352	449	475
VOM Costs	M$	362	343	325	343	342
Variable Costs of All Resources	M$	4,268	4,964	5,355	7,806	9,801
Variable Costs of All Resources	$/MWh	32.2	36.9	39.2	55.9	69.4
Variable Costs of Marginal Resource	$/MWh	43.8	55.7	63.9	82.1	100.4
Wholesale Energy Price	$/MWh	47.1	59.1	63.1	81.1	99.1
Net RPS Requirement	GWh	6,632	9,369	15,045	20,771	26,379
REC Price	$/MWh	15.0	18.4	28.3	10.3	0.0
Total RPS Cost	M$	99.5	172.4	425.5	214.3	0.0
Total RPS Cost per MWh Sales	$/MWh	1.9	3.2	7.8	3.9	0.0
Net CECs Requirement	GWh					
CECs Price	$/MWh			No Policy in Reference Case		
Total CES Cost	M$					
Total CES Cost per MWh Sales	$/MWh					

Massachusetts Typical Monthly Bills (2013$)

		2015	2020	2030	2040	2050
Residential		90	100	103	119	134
Commercial		300	339	352	410	468
Industrial		25,790	30,274	31,785	38,511	45,257

Bill impacts are modeled as a change in rates multiplied by a constant typical monthly usage: 600 kWh for residential customers, 2,000 kWh for commercial customers, and 200,000 kWh for industrial customers. The energy, or basic service, portion of rates is modeled as proportional to wholesale energy prices while the delivery portion of rates remains fixed. The percentage change in customer bills reported here is the difference in bills between the Reference and Policy Cases, given as a share of Reference Case bills.

5.3. CES Policy Case

The dynamic CES Policy Case is modeled as follows for the years 2020, 2030, 2040 and 2050:

Step #1: Retail Sales

Retail sales are identical in the Reference and Policy Cases.

Step #2: Set Model Parameters

The CES model allows users the set the following policy implementation parameters:

- CES Region: What states are implementing the CES policy? Users may choose to include or exclude any grouping of the six New England states.
- CES Load Qualification: Are MLPs required to comply with CES? If MLPs are required to comply with CES, each state's entire load is used to determine CEC purchase requirements. If MLPs are not required to comply with CES, the state loads assumed for RPS compliance are used for CES compliance.
- CES Resource Inclusion: Do the following resources generate CECs: Nuclear, Canadian imports, New York imports? These resources can be included or excluded from generating CES credits.
- CES Certificate Value: What is the lbs/MWh standard for credits for each modeled year? CES credits are assigned a value based on the difference between their emissions per MWh and a user-controlled standard.
- CES Share of Sales Required: What share of retail sales must LSEs "cover" with credits for each modeled year? Total CEC requirements depend on the user-designated share of retail sales required for compliance.

Step #3: Model Identifies and Meets CES Requirements

The model next identifies the net CECs needed to satisfy the CES requirement that do not exist in the Reference Case. This value is the total CECs required (retail sales in CES states multiplied by the share of sales included—depending on whether or not MLPs need comply—and CES policy's share of load required for compliance) less the number of RECs required to be purchased in the CES Region.

The net CEC requirement is compared to the total number of CECs available in the Reference Case (that is, all CES-eligible resources multiplied by their credits assigned per MWh, less the credits generated by RECs purchased in New England). If the CECs available in the Reference Case exceed the net CECs required, the CES policy does not bind: the credits available in the Reference Case are sufficient to allow LSEs to comply with the CES without any changes in dispatch or investments in new capacity. If, on the other hand, the net CEC requirement exceeds the CECs available in the Reference Case, the model identifies and fills this shortfall with new zero-carbon generation.

Based on this shortfall, the model calculates the GWh of new zero-carbon generation that would be necessary to both provide the additional CECs needed for compliance and replace the CECs from natural gas displaced by these new resources. The resource mix of new zero-carbon resources is a fixed modeling input. This methodology is the result of a key simplifying assumption used in the CES Policy Model: natural gas is always on the margin (that is, always determines the wholesale market price of electricity) and, therefore, is the resource displaced as new zero-carbon resources are added. The rationale for this approach is discussed below.

Step #4: CES Policy Case Outputs

The CES Policy Model estimates the same outputs for both the Reference and Policy Cases. Sections 2 and 5.4 report the results of several combinations of user inputs in the CES Policy Model in terms of "deltas"— difference between the CES Policy Case and the Reference Case.

5.4. Sensitivity Analyses

The CES Policy Model includes the capability to perform several types of sensitivity analyses including: adjustments to retail electricity sales by state; adjustments to Massachusetts RPS requirements by class; and limited optimization to meet Massachusetts electricity-sector emissions targets by modeled year. Adjustments to retail sales and the Massachusetts RPS affect both the Reference and Policy Cases. Optimization to meet emission targets may vary either the CEC certificate threshold or the share of sales required, but not both. Results of the CES Policy Model are shown in Section 2 above. In this section we discuss results of two sensitivity analyses on these results:

1. **Adjusting Massachusetts retail sales:** increasing sales by 20 percent, and decreasing sales by 20 percent, in both the Reference and Policy Cases.
2. **Adjusting electricity-sector emissions targets:** both doubling and halving the expected CECP's Clean Energy Imports strategy emission reduction target, as well as testing the CES policy's ability to achieve GWSA electric-sector target emissions. Achieving the Clean Energy Imports strategy emission reduction target—in addition to the other CECP emission reductions represented in the Reference Case—results in Massachusetts electric-sector emissions of 12.9 million sT in 2020 and 10.0 million sT in 2030. The GWSA electric-sector target is 12.4 million sT in 2020 and 8.4 million sT in 2030.

Adjusting Massachusetts Retail Sales

The CES Policy Case shown above in Table 7 (nuclear excluded, MLPs required to comply, the CEC threshold set to 2,000 lbs/MWh) requires a 74 percent share of sales requiring CECs in 2020 and 86 percent in 2030 to achieve the 5.5 million sT target emission reduction. The share of LSEs' sales required to hold CECs is functionally equivalent when this emission reduction target is replaced by the GWSA electricity-sector target emission level: 74 percent in 2020 and 86 percent in 2030. Using this target emission level, residential customers' monthly utility bills rise by 7 percent with respect to the Reference Case in 2020 and 10 percent in 2030.

Raising Massachusetts retail sales by 20 percent (in each year with respect to the Reference Case) raises the share of sales requiring CECs to 81 percent in 2020 and 91 percent in 2030 to achieve the 5.5 million sT target emission reduction; residential customers' rates rise by 7 percent with respect to the Reference Case in 2020 and 11 percent in 2030 (see Table 23). With 20 percent lower retail sales, the share of sales requiring CECs is 63 percent in 2020 and 77 percent in 2030; residential customers' rates rise by 5 percent with respect to the Reference Case in 2020 and 9 percent in 2030 (see Table 24). The difference between customer costs in the Reference Case and CES Model Case is not very sensitive to relatively large changes in future retail sales.

Adjusting Electricity-Sector Emission Targets

The CES Policy Case shown in Table 7 (nuclear excluded, MLPs required to comply, the CEC threshold set to 2,000 lbs/MWh) is set to achieve the 5.5 million sT target emission reduction. Lower emission targets necessitate lower shares of sales requiring CECs and have lower costs; higher emission targets, higher shares of sales and higher costs. When the emission reduction target is halved to 2.7 million sT, the share of sales requiring CECs falls to 67 percent in 2020 and 76 percent in 2030; residential customers' rates rise by 6 percent with respect to the Reference Case in 2020 and 9 percent in 2030 (see Table 25).

Table 23. CES Delta Results: Massachusetts Retail Sales 20-Percent Higher Than Reference Case

Delta Emissions				
		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	-9,624	-11,584
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-7,725	-8,451
Massachusetts Consumption CO_2 Emissions Rate	lbs/MWh	0	-208	-222
Delta New England Costs				
		2015	2020	2030
Supply	GWh	0	0	0
Fuel Costs	M$	0	-107	-335
CO_2 Costs	M$	0	-102	-122
VOM Costs	M$	0	-68	-88
Variable Costs of All Resources	M$	0	-277	-545
Variable Costs of All Resources	$/MWh	0.0	-1.9	-3.6
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	49,001	50,952
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		901.6	1,440.9
Total CES Cost per MWh Sales	$/MWh		12.1	18.9
Delta Massachusetts Typical Monthly Bills (2013$)				
% change from Reference Case		2015	2020	2030
Residential		0%	7%	11%
Commercial		0%	7%	11%
Industrial		0%	8%	12%

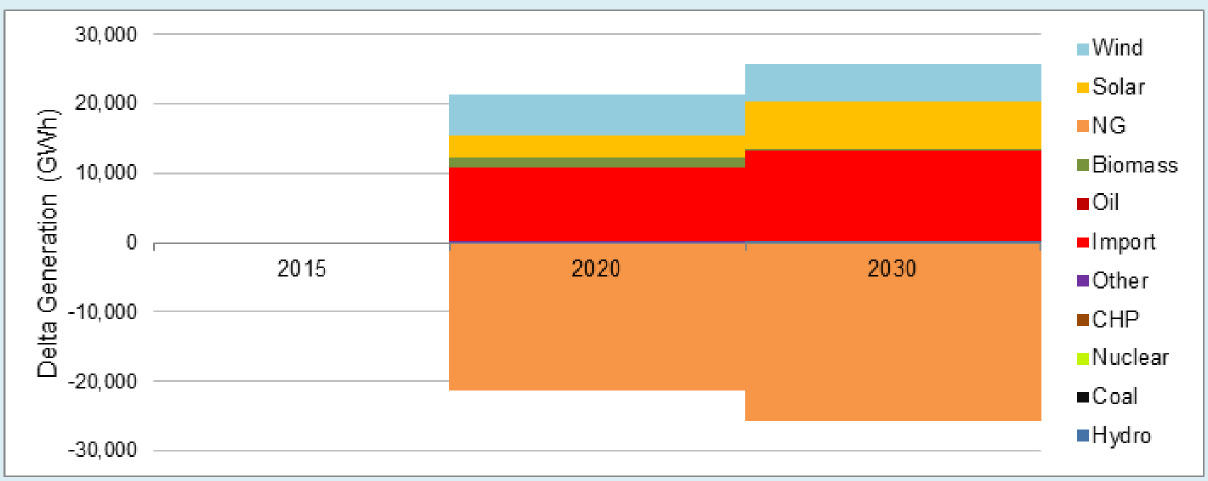


Table 24. CES Delta Results: Massachusetts Retail Sales 20-Percent Lower Than Reference Case

Delta Emissions				
		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	-5,426	-8,451
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-3,908	-5,565
Massachusetts Consumption CO_2 Emissions Rate	lbs/MWh	0	-158	-219

Delta New England Costs				
		2015	2020	2030
Supply	GWh	0	0	0
Fuel Costs	M$	0	-193	-446
CO_2 Costs	M$	0	-57	-89
VOM Costs	M$	0	-26	-44
Variable Costs of All Resources	M$	0	-277	-579
Variable Costs of All Resources	$/MWh	0.0	-2.3	-4.7
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	23,498	26,976
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		432.4	762.9
Total CES Cost per MWh Sales	$/MWh		8.7	15.0

Delta Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	5%	9%
Commercial	0%	5%	9%
Industrial	0%	6%	9%

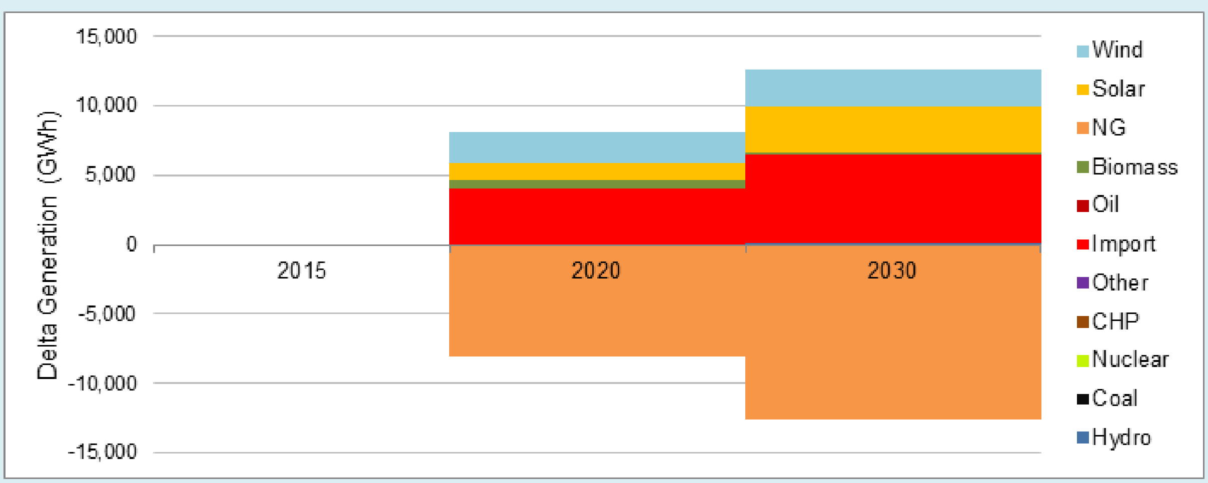


Table 25. CES Delta Results: One-half the Clean Energy Imports Strategy Expected Emission Reduction

Emissions		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	-3,474	-3,701
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-2,734	-2,734
Massachusetts Consumption CO_2 Emissions Rate	sT/MWh	0.000	-0.044	-0.043

New England Costs		2015	2020	2030
Supply	GWh	1	0	0
Fuel Costs	M$	0	-81	-151
CO_2 Costs	M$	0	-37	-39
VOM Costs	M$	0	-21	-24
Variable Costs of All Resources	M$	0	-139	-214
Variable Costs of All Resources	$/MWh	0.0	-1.0	-1.6
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	32,266	32,854
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		593.7	929.1
Total CES Cost per MWh Sales	$/MWh		9.6	14.7

Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	6%	9%
Commercial	0%	6%	8%
Industrial	0%	6%	9%

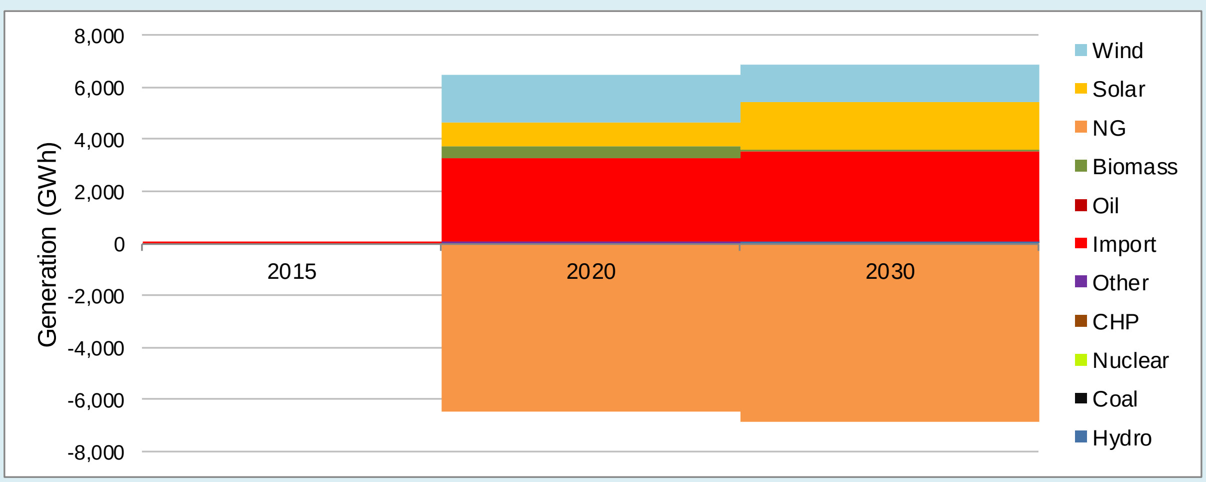


Table 26. CES Delta Results: Double the Clean Energy Imports Strategy Expected Emission Reduction

Emissions				
		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	-15,075	-17,021
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-10,935	-10,935
Massachusetts Consumption CO_2 Emissions Rate	sT/MWh	0.000	-0.177	-0.173

New England Costs				
		2015	2020	2030
Supply	GWh	1	0	0
Fuel Costs	M$	0	-352	-695
CO_2 Costs	M$	0	-159	-180
VOM Costs	M$	0	-90	-109
Variable Costs of All Resources	M$	0	-602	-983
Variable Costs of All Resources	$/MWh	0.0	-4.5	-7.2
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	43,763	46,055
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		805.2	1,302.4
Total CES Cost per MWh Sales	$/MWh		13.0	20.5

Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	8%	12%
Commercial	0%	8%	12%
Industrial	0%	9%	13%

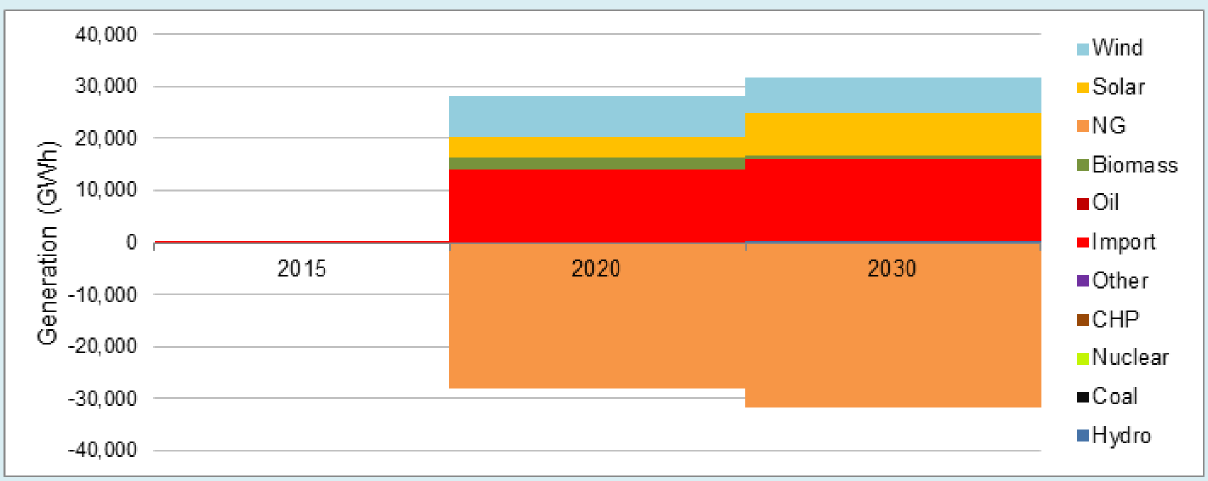
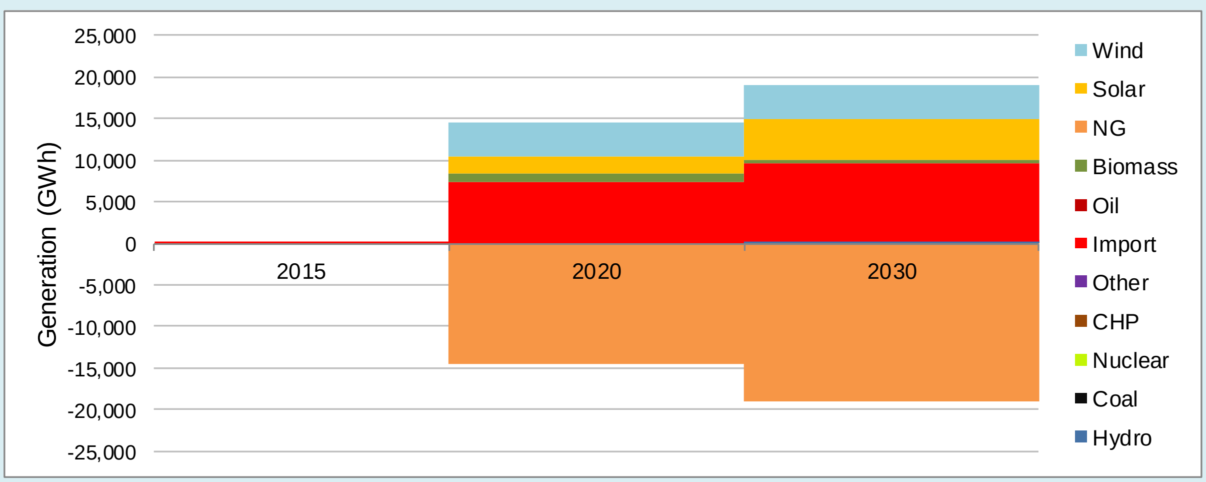


Table 27. CES Delta Results: Achieving GWSA Electricity-Sector Target Emissions

Emissions				
		2015	2020	2030
New England CO_2 Emissions (including imports)	1000 sT	0	-7,795	-10,179
Massachusetts Consumption CO_2 Emissions	1000 sT	0	-5,982	-7,118
Massachusetts Consumption CO_2 Emissions Rate	sT/MWh	0.000	-0.097	-0.112

New England Costs				
		2015	2020	2030
Supply	GWh	1	0	0
Fuel Costs	M$	0	-182	-416
CO_2 Costs	M$	0	-82	-107
VOM Costs	M$	0	-47	-65
Variable Costs of All Resources	M$	0	-311	-588
Variable Costs of All Resources	$/MWh	0.0	-2.3	-4.3
Variable Costs of Marginal Resource	$/MWh	0.0	0.0	0.0
Wholesale Energy Price	$/MWh	0.0	0.0	0.0
Net RPS Requirement	GWh	0.0	0.0	0.0
REC Price	$/MWh	0.0	0.0	0.0
Total RPS Cost	M$	0.0	0.0	0.0
Total RPS Cost per MWh Sales	$/MWh	0.0	0.0	0.0
Net CECs Requirement	GWh	No Policy	36,549	39,274
CECs Price	$/MWh		18.4	28.3
Total CES Cost	M$		672.5	1,110.7
Total CES Cost per MWh Sales	$/MWh		10.9	17.5

Massachusetts Typical Monthly Bills (2013$)			
% change from Reference Case	2015	2020	2030
Residential	0%	7%	10%
Commercial	0%	6%	10%
Industrial	0%	7%	11%



When the emission reduction target is doubled to 11.0 million sT, the share of sales requiring CECs rises to 86 percent in 2020 and 96 percent in 2030; residential customers' rates rise by 8 percent with respect to the Reference Case in 2020 and 12 percent in 2030 (see Table 26). To achieve the GWSA electricity-sector target emissions of 12.4 million sT in 2020, and the interpolated 8.4 million in 2030, necessitates a share of sales requiring CECs of 74 percent in 2020 and 86 percent in 2030; residential customers' rates rise by 7 percent with respect to the Reference Case in 2020 and 10 percent in 2030 (see Table 26).

5.5. Additional Data Assumptions

CEC Price and Zero-Carbon Resource Adoption Assumptions

Like state RPS policies, for which compliance is satisfied by the purchase of the appropriate Renewable RECs, compliance with a CES policy—designed as an LSE portfolio standard—would be satisfied with CECs. In the program design modeled, CES requirements are satisfied first with LSEs' existing purchases of RECs; the residual CES requirement is satisfied with CEC purchases. In the policy design explored in the model, RECs and CECs are essentially interchangeable for compliance. While there is a market for these RECs and future CECs, many of them are also obtained through bilateral contracts. Nonetheless, we model all RECs/CECs purchased in each year as receiving the same "market clearing" price.

RPS requirements are identified as classes or tiers with different target levels, some more restrictive than others. Typical technologies that qualify for the more stringent classes are: solar thermal electric, solar photovoltaic, landfill gas, wind, biomass, new small hydro, tidal, ocean thermal, anaerobic digestion and wave. Other less restrictive classes may include municipal solid waste, and combined heat and power. Thus within a given class a number of technologies are competing (more or less) for the same market. Likewise with CES resources, any zero-carbon generation resource would be equally attractive as a new addition to capacity, at least in terms of its ability to generate CECs.

For a single renewable technology, the cost of manufacturing the generation components may be very similar for all projects, but different renewable projects will have different delivered costs primarily because of location. For example, some locations have much greater wind power potential than others, may have different acquisition and installation costs, and also may vary in transmission cost. The characteristics of renewable resources are more varied than for fossil resources.

REC and CEC markets encourage the most cost effective resources to be installed first, irrespective of technology. Delivered prices for renewable energy are heterogeneous within each resource type. As lower cost projects are adopted, we project that the delivered prices of the next lowest-cost per-GWh project will begin to converge across various renewable resource types. At any given CES requirement level, the current mix of economically feasible projects will likely represent different technologies as well as locations. For this reason, in the CES Policy Model the new generation resources required for CES compliance are modeled as a single pool of zero-carbon resources with a single CEC price. This pool is then assigned to various specific renewable technologies using fixed shares that we have created based on our review of renewables adopted in AESC 2013 RGGI Case and the potential for new renewable capacity in New England.

New Plant Assumptions

This section presents Synapse's default or reference assumptions for key economic and operating parameters of common types of generic new generating resources used in the CES model. These parameter values are based upon our review of the relevant assumptions in the public sources listed in Table 29, as well as our experience in various resource planning proceedings and consulting engagements.

Table 28. New Utility Scale Generation Resources—Operational Parameters

Generation Type	Heat Rate (Btu/ kWh)	Variable O&M (2010$/ MWh)	Fixed O&M (2010$/ kW)	Typical Capacity Factor	Capacity Value for Load
Coal Steam	8,800	4.28	29.9	80%	100%
Coal IGCC	8,700	6,93	59.69	80%	100%
Coal IGCC w/CCS	10,700	9.01	69.84	80%	100%
Gas CC	7,050	3.44	14.5	80%	100%
Advanced NG CC	6,430	3.13	14.73	80%	100%
Advanced NG CC w/CCS	7,525	6.5	30.49	70%	100%
Gas CT	10,745	8.31	9.95	10%	100%
Adv CT	9,750	7.04	14.81	10%	100%
Fuel Cells	9,500	0	352.72	90%	100%
Nuclear	10,453	2.04	89.44	85%	100%
DG – Base	9,050	7.52	16.91	70%	100%
DG – Peak	10,069	7.52	16.91	10%	100%
Biomass	13,500	7.08	101.29	70%	100%
Geothermal	30,000	9.71	109.42	70%	100%
MSW/Landfill	13,648	8.39	376.67	70%	100%
Hydro	9,854	2.47	13.82	50%	100%
Wind Land	9,854	0	28.28	38%	15%
Wind Offshore	9,854	0	88.72	40%	20%
Solar Thermal	9,854	0	64.49	21%	60%
Solar PV (utility)	9,854	0	34.38	21%	58%

Heat rate: Efficiency at which the unit converts fuel energy into electricity. Values are from EIA 2011b, Table 8.2 Cost and performance characteristics of new central station electricity generating technologies.

Variable O&M: Variable operating costs not including fuel and emission costs. Values are from EIA 2011b, Table 8.2 Cost and performance characteristics of new central station electricity generating technologies, except for the Solar PV variable O&M, which is based on Synapse expertise.

Fixed O&M: Fixed operating cost. Values are from EIA 2011b, Table 8.2 Cost and performance characteristics of new central station electricity generating technologies, except for the Solar PV fixed O&M, which is based on Synapse expertise.

Typical Capacity Factor: Portion of nameplate capacity used on average over a year in typical use (capacity factor = annual generation / (capacity * 8,760 hours)). Capacity factor of wind and solar units vary significantly by location. Certain values are from EPRI 2011, Table 1-2 Representative Cost and Performance of Power Generation Technologies (2015), while other values are based on Synapse expertise.

Capacity Value for Load: Portion of nameplate capacity that is credited as firm capacity to satisfy system capacity requirements; this value can vary significantly for wind and solar. These values are based on Synapse expertise.

Table 29. New Utility Scale Generation Resources: Source Documents

Black & Veatch 2011. Ryan Pletka, Black & Veatch's (RETI's) Cost of Generation Calculator, Presentation to the California Energy Commission Cost of Generation Workshop, May 16, 2011.
E3 Analytics 2010. Energy and Environmental Economics, Capital Cost Recommendations for 2009 TEPPC Study, http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/Forms/AllItems.aspx
EIA 2010. U.S. Energy Information Administration, Updated Capital Cost Estimates for Electricity Generation Plants, November 2010, http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf
EIA 2011a. U.S. Energy Information Administration, Annual Energy Outlook 2011, April 2011, www.eia.gov
EIA 2011b. U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2011, Electric Market Module, July 2011, www.eia.gov
EPRI 2011, Electric Power Research Institute, Program on Technology Innovation: Integrated Generation Technology Options, publication 1022782, Technical Update June 2011, www.epri.com
Lazard 2010. Lazard, Ltd., Levelized Cost of Energy Analysis – Version 4.0, May 2010.
NREL 2010, National Renewable Energy Laboratory, Cost and Performance Assumptions for Modeling Electricity Generation Technologies, ICF International, NREL/SR-6A20-48595, www.nrel.gov
NREL 2012, National Renewable Energy Laboratory, Recent developments in the Levelized Cost of Energy from U.S. Wind Power Projects, February 2012.

5.6. Model Limitations and Caveats

Among the key design principles required by MassCEC and the Agencies for Synapse's model of a CES policy were simplicity and transparency adequate to allow for a tool that could be used to explore a wide range of policy assumptions, without significant per-scenario modeling "run" costs. The CES Policy Model meets this specification in the form of a streamlined Excel-based spreadsheet, with limited use of VBA macros for optional optimization analysis only.

Simplicity and transparency in modeling, of course, come at the cost of some loss of complexity in the representation of real-world conditions. Three modeling assumptions in particular stand out as limits to the confidence with which CES Policy Model results may be presented:

1. **REC and CEC prices converge over time.** Because of the large demands of Massachusetts' existing RPS policy and the expectation of heterogeneous delivery costs within resource types, we assume that REC and CEC prices will converge over time. As a practical matter, in the CES Policy Model there is one set of fixed prices shared by both RECs and CECs (in 2013 dollars per MWh): $15.00 in 2015, $18.40 in 2020, $28.28 in 2030, $10.10 in 2040, and $0.00 in 2050. REC/CEC prices are expected to decline after 2030 as renewables take the place of natural gas on the margin of the wholesale energy market. The greater the demand for CECs (above that of RECs) in early years, the more likely that this assumption is incorrect.

2. **Only natural gas is displaced.** Newly built (or newly imported) zero-carbon resources are expected to displace only natural gas. More CO_2-intensive coal and oil resources are not displaced by additional dispatch of existing natural gas, or by investment in new natural gas or zero-carbon resources. Instead, coal and oil are almost entirely retired by 2030 in the Reference Case—without the assistance of a CES policy. In essence, natural gas is assumed to be always and everywhere (in New England) the price-setter in the wholesale energy market. If coal and oil prices fall with respect to that of natural gas in the period modeled, this assumption will be incorrect.

3. **The mix of new zero-carbon resources is fixed.** When additional CECs—beyond those available in the Reference Case—are required for CES compliance, new zero-carbon resources are built and natural gas is displaced in the CES Policy Model. We assume that the resource mix (the shares of various renewable technologies and imports) of the zero-carbon generation added is a policy choice that cannot be well modeled as a function of economic drivers. We have based this fixed resource mix on our best knowledge regarding future prices and availability of renewables and Canadian imports in the future. This model cannot, therefore, offer any policy advice regarding the likely share of Canadian imports in that zero-carbon resource mix, or on the impact of the costs of these imports or changes to their assumed share. In the CES Policy Model, in effect, all newly built or newly imported resources are assumed to have the same price. We are not aware of sufficient evidence for an assumption that Canadian imports, instead, will have a lower delivered price to New England than will domestic renewables.