# Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study

Phase II: Mechanisms Analysis
Spring 2018

New England States Committee on Electricity

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# I. Executive Summary

There are a variety of means by which states may choose to support meeting their renewable and clean energy requirements. No one mechanism is inherently superior and directly comparing mechanisms is challenging. Consideration of whether and to what extent one mechanism might better achieve a state's objectives than another requires judgment and depends in large part on a state's short-term and long-term specific objectives. This paper provides information about the factors a state should consider when weighing mechanism options and directional consumer cost implications. *This paper is not an endorsement of, or judgment about, any particular mechanism or public policy and should not be interpreted as such.*

Specifically, this paper further analyzes the mechanisms NESCOE described in the Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study – Phase I: Scenario Analysis. This paper, Phase II: Mechanisms Analysis, examines potential economic, regulatory, and market implications of mechanisms to support new and existing renewable and clean energy resources. The mechanisms include (1) Renewable Portfolio Standards ("RPS"), (2) Clean Energy Standards ("CES"), (3) Long-Term Contracts, (4) Strategic Transmission Investments and (5) a Forward Clean Energy Market ("FCEM").

The latter, an FCEM, is more a concept than a mature mechanism. The concept emerged in New England stakeholder discussions about potential ways the region's wholesale competitive markets might be harmonized with the requirements of state laws. Unlike the others that fall under state jurisdiction, the FCEM would be administered by ISO-NE, and thus fall under the jurisdiction of the Federal Energy Regulatory Commission. This paper seeks to facilitate consideration of the FCEM concept along with other options. Because the FCEM is new and untested, NESCOE particularly welcomes comments, criticisms and alternative analysis that merit states' consideration.

As noted, judgment about a particular mechanism requires a fact- and objective-specific assessment. When assessing mechanisms, some questions a reader should consider include the following:

- What quantity of resources are required?
- How frequently will new resources be required?
- Is diversity of resources important, such as resource size, type, operational characteristics, and/or location?
- Is large-scale transmission required or desired?
- In light of required volumes, does the mechanism maintain a competitive wholesale market that sends proper price signals to *all* resources to serve consumers at the lowest cost over the long-term?
- What is the preferred placement of risk by and between resource developers and consumers?
- How are jurisdictional issues weighed?

Against that backdrop, three of the mechanisms - the RPS, CES, and FCEM - would have similar costs if they had the same resource eligibility and quantity targets. That is because these mechanisms pay all eligible resources the same price – the price of the most expensive eligible resource.

The Strategic Transmission Investment mechanism appears to cost less than the RPS, CES and FCEM because it places the cost of transmission in a bucket separate from the clean energy resource. Consumers hold that bucket too, but the costs in it are separated from the clean energy resource's bucket.

The Long-Term Contracts mechanism also *appears*, in this analysis, to be less expensive than the other mechanisms. That is because the Long-Term Contract mechanism pays each resource exactly *the amount of the specific resource's* missing money where, as noted, the RPS, CES and FCEM pay *all* eligible resources the same amount equal to the price of the most expensive eligible resource. The Long-Term Contract mechanism's costs do not show, however, the costs of getting one or more assumptions wrong, the costs consumers would *not* pay if that (or other) resource's costs drop over the contract term, or the missed opportunity for diversity in resources' type, size, operating characteristics, costs and/or location. The Analysis is based on assumptions, many of which will turn out to be inaccurate with the passage of time. In addition, the renewable and clean energy resource additions in Phase I were assumed, hypothetical future scenarios and may not necessarily represent actual future outcomes.

Perhaps the most significant factor influencing consumer costs is a state's target quantity of renewable or clean energy. Generally, the cost differences from mechanism to mechanism are smaller than the cost differences that result from adjusting state targets and the costs of resources capable of meeting state objectives.

# II. Introduction and Background

This paper describes an economic analysis of some of the possible incentive mechanisms states may wish to use to support meeting their renewable and clean energy requirements. Specifically, it further analyzes the mechanisms NESCOE describes in the Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study – Phase I: Scenario Analysis ("Phase I").[1]

The Phase II: Mechanisms Analysis ("Analysis") follows the March 2017 Phase I Report.[2] Phase I analyzed various future scenarios based on modeling conducted by London Economics International ("LEI"). Building on Phase I, the Analysis examines potential economic, regulatory, and market implications of mechanisms to support new and existing renewable and clean energy resources. The Analysis also explains the mechanics of various tools the states may use to achieve public policy requirements.

Various state laws require increasing levels of renewable and/or clean energy. Other laws require specific reductions in carbon emissions. As the requirements of state laws increases, the mechanisms states use to execute those laws are increasingly important. These mechanisms have implications regarding consumer costs, the region's electric resource mix, the competitive wholesale markets, the balance of risk between investors and consumers, and impacts on system reliability.

The Analysis focuses on the five mechanisms listed below. There are others, such as the Regional Greenhouse Gas Initiative ("RGGI"), and various other requirements in states' laws. Some of the mechanisms examined in this paper have been used in New England. Some have been used in other regions. One is a potential wholesale market mechanism that has been discussed preliminarily in the New England stakeholder process known as Integrating Markets and Public Policy ("IMAPP").[3]

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1 The Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study follows a December 2015 Whitepaper, Mechanisms to Support Public Policy Resources in the New England States (2015 Mechanisms Whitepaper). The 2015 Mechanisms Whitepaper identified a range of mechanisms, such as Renewable Portfolio Standards, clean energy standards, and long-term contracting, available to states to support resources capable of satisfying various objectives, such as the use of renewable fuels, carbon dioxide emissions reduction, supporting emerging technologies, and promoting fuel diversity. It described various mechanisms' mechanics, as well their interaction with New England's competitive wholesale markets and some legal and regulatory issues. *See* http://nescoe.com/wp-content/uploads/2015/12/PublicPolicyMechanisms_December2015.pdf.

2 Phases I and II of the Mechanisms 2.0 Study are intended to be complementary and, once completed, should be read in conjunction with one another. Phase I is available at http://nescoe.com/wp-content/uploads/2017/03/Mechanisms_PhaseI-ScenarioAnalysis_Winter2017.pdf.

3 The New England Power Pool's ("NEPOOL") IMAPP initiative examined the interaction between wholesale markets and state policy requirements. Within the IMAPP process, ISO New England, New England states, market participants, and stakeholders explored potential solutions to address such interactions. In general, potential solutions were categorized as either near-term "accommodate-style" proposals or longer-term "achieve-style" proposals. For more information, *see* NEPOOL's website, available at http://www.nepool.com/IMAPP.php. NESCOE's perspective on some other mechanisms discussed in the IMAPP context (e.g, carbon pricing and two-tier capacity pricing) is available at http://www.nepool.com/uploads/IMAPP_20170517_NESCOE_Memo_20170407.pdf and http://www.nepool.com/uploads/IMAPP_20161021_NESCOE_2Tiered_Pricing_Analysis.pdf.

This paper begins with a discussion on each of the five mechanisms:

1. Renewable Portfolio Standards ("RPS")
2. Clean Energy Standards ("CES")
3. Long-Term Contracts
4. Strategic Transmission Investments
5. Forward Clean Energy Market ("FCEM")

Each of these sections describes the identified mechanisms that states could use to help meet the requirements of state laws. The Phase I and additional modeling results inform economic analysis and graphical illustrations for each mechanism. The illustrations show how the mechanisms work and the impact of certain design features. Next, these sections identify and describe various economic and implementation issues associated with each mechanism, including components of each mechanism that provide benefits and present challenges. For each mechanism, the paper identifies some questions for state consideration if a state wishes to implement such mechanism. Finally, the paper makes broad comparisons across mechanisms and presents some observations for consideration.

*This paper is not an endorsement of, or judgment about, any particular mechanism or public policy and should not be interpreted as such. Any views that may be expressed in, or inferred from, this paper should not be construed as representing those of NESCOE, any NESCOE Manager, or any state agency or official. While the paper draws on examples and research from outside the region, the scope of the paper pertains to New England. The information provided is largely based on modeling and assumptions or drawn from publicly available reports and other documents. The results are directionally indicative and are not a substitute for actual project costs that would be identified through competitive or market processes. A reader should not make decisions based on the information in this paper without independent verification.*

### *A. Phase I Scenarios and "Missing Money"*

Phase I, completed in 2017, analyzed various future scenarios based on modeling that LEI conducted. Phase I shows the potential implications of various hypothetical renewable and clean energy futures on existing and new resources in New England, and ultimately on the consumers who pay for them. LEI analyzed New England wholesale electric energy and capacity market dynamics in two future years - 2025 and 2030 - under various hypothetical future market conditions that NESCOE defined. LEI estimated the going-forward costs and future electricity market revenues for existing and new generation resources in New England with a focus on renewable and clean energy resources. ***Importantly, LEI estimated the amount of "missing money" for each resource type. In this paper, "missing money" means the amount by which a resource's costs exceed its forecasted wholesale electricity market revenues.*** LEI also examined power sector air emissions under a range of future scenarios.

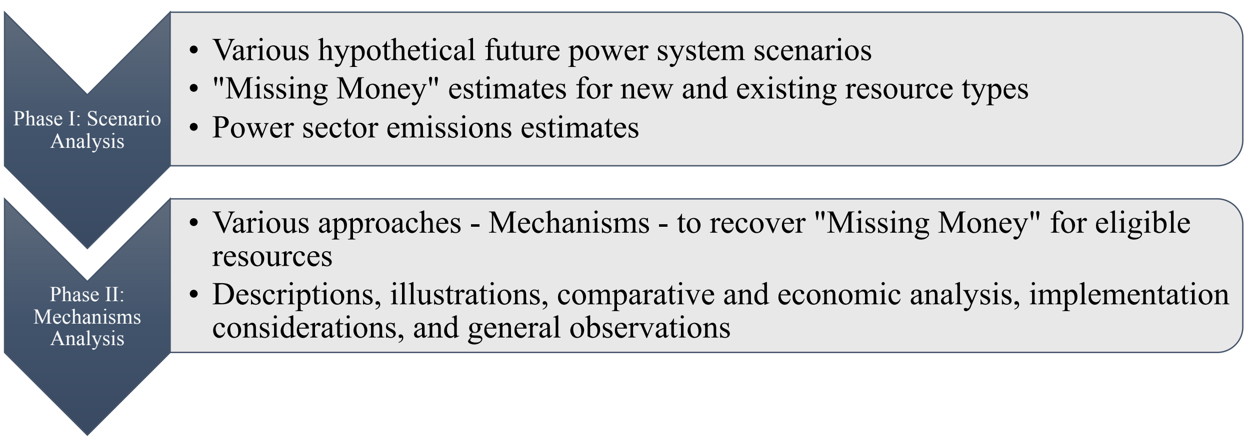
The concept of "missing money" is of central importance to this Analysis. "Missing money" is a substitute for resource profitability.[4] In this analysis, a resource type that has "missing money" is less likely to be profitable on electricity market-based revenues alone. The mechanisms discussed in this paper are different ways that eligible resources can recover "missing money" and become or remain profitable.

Phase I and the additional FCEM modeling presented in this paper provides "missing money" estimates for a range of hypothetical future scenarios with varying levels of renewable and clean energy resources. Phase II uses these "missing money" estimates to inform the mechanisms analysis. Figure 1 below presents the calculation of "missing money" estimates.

**Figure 1: Relationship Between Market-Based Revenues and Resource Profitability**


Phase II uses the Phase I modeling results and additional modeling results for an FCEM scenario to inform economic analysis and provide graphical illustrations that explain and compare each mechanism. The analysis in this paper is based on the scenario analysis assumptions. Figure 2 below presents, at a high level, the ways in which the Phase I: Scenario Analysis and the Phase II: Mechanisms Analysis fit together.

**Figure 2: Overview of Phases I and II**

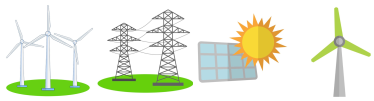
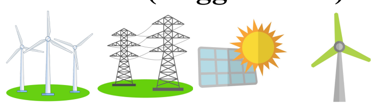
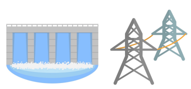
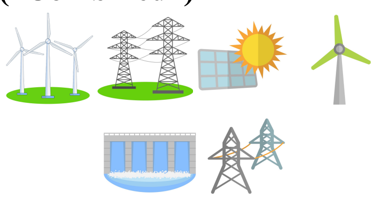
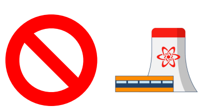
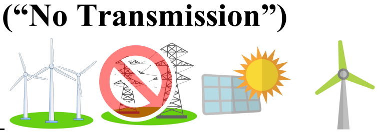



As a reminder, Table A below presents the Phase I hypothetical renewable and clean energy scenarios. These scenarios (and the associated amounts of additional renewable and clean

4 "Missing money" is shorthand for costs exceeding revenues (i.e., not breaking even). Some resource types are projected to earn enough electricity market revenues to more than cover estimated costs (i.e., more than breaking even). Mathematically, resources whose revenues exceed costs would have 'negative' missing money (i.e., profits). Separately, estimated costs for new resources are generally higher than existing resources' costs. For example, existing resources have much lower debt payments, compared to new resources. Importantly, LEI also does not include equity returns or significant capital expenditures for existing resources, which further increases the cost difference between new and existing resources.

energy resource additions) directly influence the Phase I "missing money" estimates discussed throughout the paper.

**Table A: Overview of Phase I Scenarios and Assumption Details**

| Scenario | 2025 | 2030 |
|---|---|---|
| **1: Expanded RPS 35%-40% ("Expanded")**  | + 2,750 MW On-Shore Wind<br>(+2,400 MW HVDC)<br>+ 600 MW Solar PV<br>+1,500 MW Off-Shore Wind | +3,575 MW On-Shore Wind<br>(+2,400 MW HVDC)<br>+1,000 MW Solar PV<br>+2,000 MW Off-Shore Wind |
| **2: More Aggressive RPS 40%-45% ("Aggressive")**  | +4,250 MW On-Shore Wind<br>(+3,600 MW HVDC)<br>+1,000 MW Solar PV<br>+2,000 MW Off-Shore Wind | +5,500 MW On-Shore Wind<br>(+3,600 MW HVDC)<br>+1,250 MW Solar PV<br>+2,500 MW Off-Shore Wind |
| **3: Clean Energy Imports ("Imports")**  | +7,800 GWh Clean Energy<br>(+1,000 MW HVDC)<br>(90% Capacity Factor) | +7,800 GWh Clean Energy<br>(+1,000 MW HVDC)<br>(90% Capacity Factor) |
| **4: Combined Renewable and Clean Energy ("Combined")**  | +4,250 MW On-Shore Wind<br>(+3,600 MW HVDC)<br>+1,000 MW Solar PV<br>+2,000 MW Off-Shore Wind<br><br>+7,800 GWh Clean Energy<br>(+1,000 MW HVDC) | +5,500 MW On-Shore Wind<br>(+3,600 MW HVDC)<br>+1,250 MW Solar PV<br>+2,500 MW Off-Shore Wind<br><br>+7,800 GWh Clean Energy<br>(+1,000 MW HVDC) |
| **5: Nuclear Retirements ("No Nuclear")**  | Retire remaining nuclear resources by 2025;<br>Nuclear resources replaced by gas-fired resources | Retire remaining nuclear resources by 2025;<br>Nuclear resources replaced by gas-fired resources |
| **6: Expanded RPS Without Transmission ("No Transmission")**  | +4,250 MW On-Shore Wind<br>~~(+3,600 MW HVDC)~~<br>+1,000 MW Solar PV<br>+2,000 MW Off-Shore Wind | +5,500 MW On-Shore Wind<br>~~(+3,600 MW HVDC)~~<br>+1,250 MW Solar PV<br>+2,500 MW Off-Shore Wind |

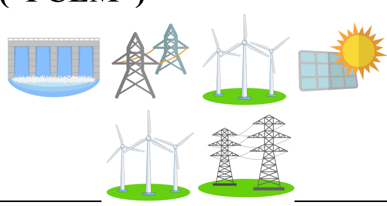
### *B. <u>Phase II FCEM Scenario and Mechanisms</u>*

Building on Phase I, Phase II provides economic, regulatory, and market analysis of mechanisms to support new and existing renewable and clean energy resources needed to meet state requirements. Phase II uses the Phase I modeling results and analysis of an FCEM scenario to explain the various mechanisms states could use to satisfy the requirements of state laws. The analysis of an FCEM provides another scenario with an updated[5] renewable and clean energy supply outlook that meets the aggregated states' hypothetical requirements.

The additional modeling for the FCEM is directly comparable to the Phase I modeling. For example, this scenario used the same load forecast and natural gas price forecast as Phase I. The difference is the supply of new renewable and clean energy resources, the prices and available quantities of which will be based on LEI's updated outlook for these resources. All other modeling assumptions will be the same as Phase I.

The FCEM has complex features, discussed further below in Section VII. This Analysis simplifies the FCEM mechanism to focus on the economics of the clean energy attribute. LEI performed computer modeling to examine the potential impacts of an FCEM. LEI's FCEM analysis included a supply outlook for eligible clean energy resources.[6] All existing and new Class I RPS-eligible resources plus new imported hydropower were eligible for participation in the FCEM. ***LEI assumed demand for clean energy attributes in the LEI FCEM analysis equal to the Phase I analysis 'More Aggressive RPS 40-45%' scenario's demand for renewable energy.*** LEI combined all of these elements to project FCEM market participation and forecast the resulting resource mix. LEI then forecasted prices in the FCEM and estimated consumer costs for an assumed level of demand for clean energy (the RPS 40-45 level of demand).

**Table B: Overview of FCEM Scenario and Assumption Details**

| Scenario | 2025 | 2030 |
|---|---|---|
| **Forward Clean Energy Market 40%-45% ("FCEM")**<br> | +7,875 GWh Clean Energy<br>(+1,000 MW HVDC)<br>(90% Capacity Factor)<br><br>+925 MW On-Shore Wind<br>+2,275 MW Solar PV<br>+3,550 MW On-Shore Wind<br>(+3,600 MW HVDC) | +7,875 GWh Clean Energy<br>(+1,000 MW HVDC)<br>(90% Capacity Factor)<br><br>+925 MW On-Shore Wind<br>+4,775 MW Solar PV<br>+4,050 MW On-Shore Wind<br>(+3,600 MW HVDC) |

5 The Phase I Scenario Analysis assumed certain levels, types, and timing of renewable and clean energy resource development. The Base Case did not meet states' collective RPS requirements due to LEI's view on transmission system limitations inhibiting further development of resources in the interconnection queue in the summer of 2016. The FCEM scenario includes LEI's updated renewable and clean energy development outlook in proportion to states' collective hypothetical requirements.

6 In contrast, the Phase I analysis *assumed* certain levels and types of new renewable resources would be developed. The LEI FCEM analysis *forecasts* the resource types and offer prices based on an assumed level of demand.

# III. Renewable Portfolio Standards

## *A. RPS Mechanics*

Each of the six New England states has adopted an RPS to support certain renewable resources.[7] Several New England states enacted their RPS programs at the same time that they restructured the electricity industry in their state.[8] These states created the RPS to support renewable energy resources through a market-based mechanism that would be compatible with the competitive wholesale electricity industry designed to select the lowest cost resources.

An RPS requires state-jurisdictional utilities and load-serving entities to:

(1) buy an amount of Renewable Energy Certificates ("RECs") in proportion to a percentage of retail load served in a given year, *or*

(2) pay a fee called an Alternative Compliance Payment ("ACP").

An ACP caps the amount of money consumers will spend to satisfy the state's RPS requirement.[9] In general, an ACP indicates that, while the state has determined consumers will fund a certain amount and type of renewable resources, consumers will not fund these resources at any cost.

An RPS' requirement to buy RECs (or pay the ACP) creates a market for renewable energy attributes. In this market, eligible resources earn additional revenue over and above other wholesale market revenues by selling RECs. In general, producing one megawatt hour ("MWh") of electric energy allows eligible resources to create and sell one REC. In theory, the minimum price at which a renewable resource is willing to sell its RECs is typically the amount of its going forward costs that the resource does not recover through other electricity markets (e.g., energy, capacity, and ancillary services).[10] As discussed further below, a renewable resource receives the short-term market price for its RECs, which may not be equal to remaining going forward costs.

In general, eligible resources must be able to deliver power into the ISO New England ("ISO-NE") system. In practice, this has meant that eligible resources must be physically located in New England or in neighboring systems, such as the New York ISO and adjoining Canadian provinces (i.e., Quebec).

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7 In Rhode Island and Vermont, the term "Renewable Energy Standard" or "RES" is utilized. *See* R.I. Gen. Laws § 39-26, 30 Vermont Statutes Annotated § 8004. For ease, this report will utilize the more common term, RPS.

8 *See* Connecticut Public Act No. 98-28, An Act Concerning Electric Restructuring (1998), Maine P.L. 1997 ch. 316, An Act to Restructure the State's Electric Industry (1997), and Massachusetts 1997 Acts 164, An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein (1997). For more information, see *Electric Restructuring in New England – A Look Back* (December 2015), available at http://nescoe.com/wp-content/uploads/2015/12/RestructuringHistory_December2015.pdf.

9 States usually direct that ACPs paid in a given compliance be used to support renewable and other clean energy development loan funds.

10 *See* Cory, K., *Renewable Energy Financing: The Role of Policy and Economics* (2008), available at https://www.nrel.gov/docs/fy08osti/42918.pdf.

Each state's RPS law determines:

- resource eligibility
    - resources historically eligible across all six states include wind, solar, small hydropower, biomass, landfill gas, and ocean power; each state's definition includes various other resources as well, such as for example, fuel cells in Connecticut or Maine
- whether to create a class or tier system to give preference to certain types of renewable energy, for example, a solar Photovoltaic ("PV") requirement
- the target amount for each tier or class over time, and
- the dollar amount of – or calculation for setting – the state's ACP level over time.

State laws may differ on each of these points. However, there is sufficient commonality across New England states' RPS programs to produce and support a regional marketplace for buying and selling RECs. For example, as noted, about six renewable energy technologies are eligible for RECs in more than one state. This allows renewable energy resources to sell their RECs to the highest bidder anywhere in New England or in a neighboring system.

There is no organized or centralized market for RECs.[11] Therefore, most REC transactions are between a resource and a utility or load-serving entity. This is referred to as a bilateral transaction.[12] Bilateral transactions results in some differences from transaction to transaction. Despite these differences, the REC market in New England generally reflects overall supply and demand in the short term.

### *B. <u>RPS Illustration</u>*

The graphic below, Figure 3, presents the aggregated supply of RECs from new renewable resources in New England for a hypothetical future year. Based on the assumed amounts of new renewable resources from the Phase I: Scenario Analysis, Figure 3 shows the aggregated supply of RECs by price, from lowest price on the left to highest price on the right. The price levels in this illustration are equal to the so-called "missing money" amounts estimated in Phase I for this

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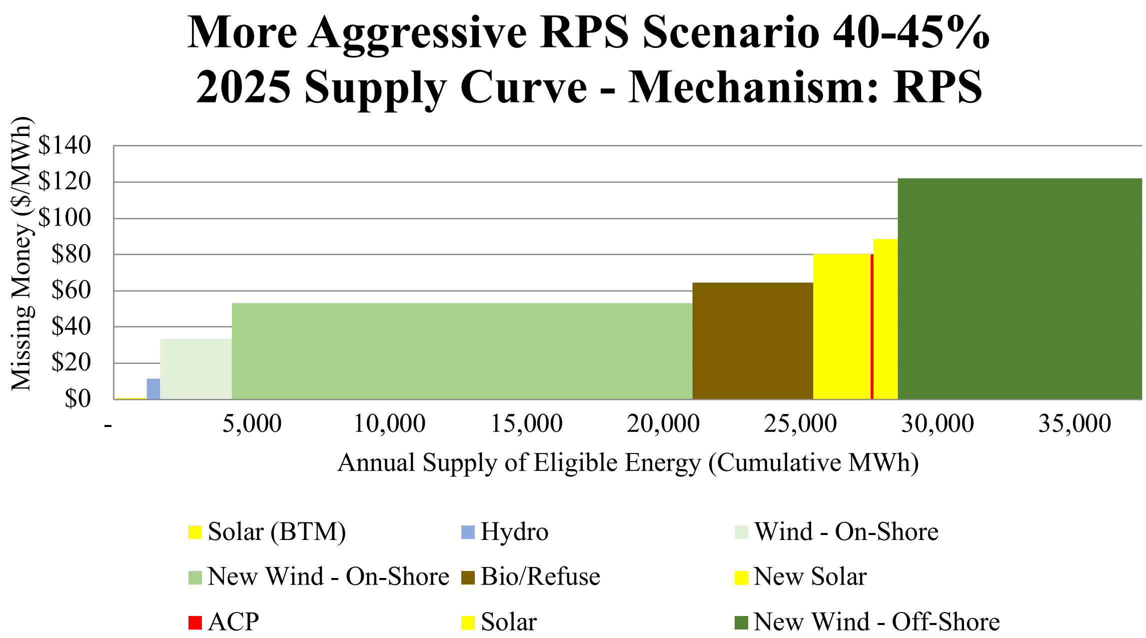
[11] The NEPOOL Generation Information System ("NEPOOL GIS") issues and tracks certificates for all MWh of generation and load produced in the ISO New England control area, as well as imported MWh from adjacent control areas. For more information, *see* http://www.nepoolgis.com/.

[12] Bilateral REC transactions are commonly the result of competitive procurement processes conducted by the state-regulated electric distribution utilities (e.g., Requests for Proposals or RFPs). Bilateral transactions also arise through direct communication and negotiation between buyers and sellers in primary and secondary markets. In some states, utilities have the option to take ownership of renewable distributed generation built pursuant to statute and utilize the RECs generated by these projects.

hypothetical future year.[13] Figure 3 also includes an assumed ACP level ($80 in 2025, $88 in 2030).[14]

**Figure 3: Illustration of RPS Mechanism**




In general, the market price for RECs is determined by the combination of supply and demand, and capped by the ACP. In this analysis, demand for RECs is equivalent to the combined product of each state's target percentages and retail load for a given year.

The owner of a renewable resource would of course seek to maximize its revenue, as would the typical owner of any other product making a sale. Due to competitive forces, renewable resources in the regional market are paid the highest price the market will bear, capped by the individual state-established ACP. Thus, the market price for RECs is set at the point at which the aggregate level of demand intersects with the region's aggregated supply.[15] For this reason, an RPS mechanism typically results in a *single price paid to all resources* for a given time period

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13 LEI's analysis identified the amount of money existing and new resource types would need to "break even" financially. The analysis is intended to show which resource types might need revenues in excess of what the New England wholesale electricity markets will pay them, according to the LEI model. This study refers to that difference as "missing money." For more information, *see* Section II A above.

14 *See* Appendix A: Renewable and Clean Energy Targets and Alternative Compliance Payments for more information about this illustrative assumption.

15 This describes the so-called "spot" market price for RECs. In the normal course some resources sell future RECs on a "forward" basis, either as a separate product or as part of a bundled power purchase agreement that includes RECs, energy, and capacity. Such forward sales are an indication of the expected future spot market price.

(in this case, hypothetical year future 2025 in the Expanded RPS scenario) unless there are caps or other restrictions on the price.[16]

The example discussed above is directly influenced by the assumed supply of and demand for RECs in the region. The aggregated REC supply presented above assumes diversity among new renewable resource types in a future year. Such diversity may not, in fact, exist; in reality, different renewable resource types have different degrees of risk tolerance and seek different levels of reward. Naturally, investors tend to favor resource types that are most profitable and present the lowest investment risk. Accordingly, an RPS tends to result in a supply of similar new renewable resource types. Due to these factors, on-shore wind makes up the majority of new renewable resource additions in New England in terms of MWh.

### C. ***RPS Design Considerations***

RPS programs are generally designed to achieve competition among renewable resource types. States often use a classification system - classes or tiers - to provide different incentives for:

- **new vs. existing resources** (year placed in service or "vintage")
- **established vs. emerging** technologies
- **scales of production** ("smaller" resources – e.g., less than 20 MW)[17]

Some states also use "carve-outs" within a class to further encourage resource type diversity.

This carve-out approach can support resource diversity at added costs to consumers because it divides the overall supply of RECs into slices, and each slice has a different price level. An example of such an approach is presented in Figure 4 below.

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16 The effects of fuel-, technology-, and vintage-related requirements (i.e., Classes or Tiers and so-called Carve-outs) are discussed below.

17 The study focuses on the "missing money" economics for utility-scale resource types. Separately, energy efficiency and distributed (i.e., "behind-the-meter" or "BTM") solar PV resources are included in the modeling load forecasts. BTM solar PV resources are generally eligible for RPS. Accordingly, RECs from BTM solar PV are included in the relevant mechanism illustrations.

**Figure 4: Illustration of RPS Mechanism with Two Tiers**

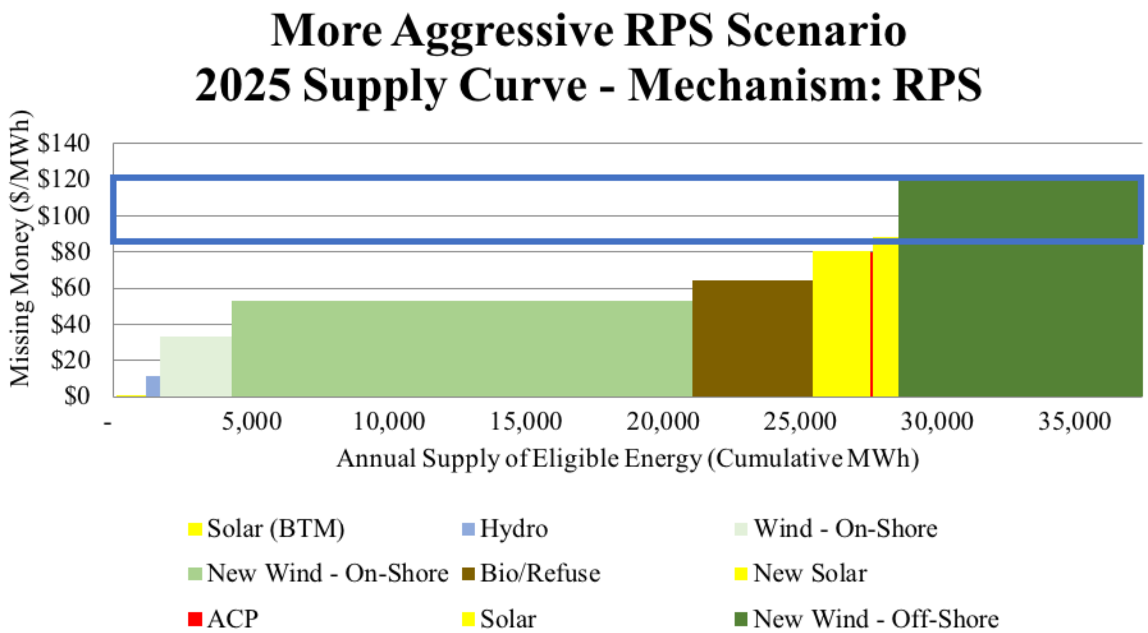


Figure 4 above illustrates how carve outs in an RPS system can: (1) promote diversity among RPS-eligible resource types and (2) affect the price consumers will pay for RECs.

In this example, the demand for Class I resources is separated into (a) regular Class I resources and (b) a carve-out for solar and off-shore wind. The regular Class I resources are paid the highest price the market will bear excluding solar and off-shore wind. In this example, biomass sets that price. The hydro, existing on-shore wind, new on-shore wind, and biomass resources are paid the amount associated with (the highest-priced) biomass's "missing money" from Phase I. Consumers pay more for the carved-out solar and off-shore wind at the highest price that market will bear (the amount associated with off-shore wind). In exchange, consumers get a more diverse supply of renewable resources. The choice for states is to what extent diversity in RPS-supported resources is important compared to the additional consumer cost.

### *D. <u>RPS Benefits and Challenges</u>*

Most states first implemented RPS programs at the time of electric industry restructuring in the late 1990s. The new competitive wholesale market was designed to select resources at the lowest cost to consumers. It was not designed to select resources based on emissions or any other factor, other than cost.[18] States adopted RPS requirements to ensure resources that satisfy certain energy and environmental objectives would be built. An RPS mechanism is generally considered to be compatible with competitive wholesale electric markets. That states have maintained RPS programs over the years suggests that states view RPS requirements as helping to achieve policy objectives.

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[18] Specifically, the wholesale electricity markets are designed to economically commit and dispatch resources in offer price merit order within the constraints of safely and reliably operating the transmission system. Such transmission security constraints are reflected in prices at different locations throughout the system.

In recent years, some renewable resource owners and advocates have expressed a view that *short-term* incentive mechanisms, like REC markets, are inadequate to support new resources. For example, RENEW, a renewable energy industry and advocates trade association in New England and New York, offered the following principles in an August 2016 regional dialogue about policies and markets and expressed a preference for *long-term* contractual commitments:

- *Short term markets are not the only markets; historically, long-term contracts were a standard feature of electricity markets*
- *Deregulated markets, while they have many benefits, have not created an environment conducive to the vigorous, competitive, long-term bilateral contracting that can provide great benefits to consumers and financial certainty to suppliers*
- *New renewable energy projects need long-term commitment for project finance; short-term energy markets simply do not create sufficient certainty of long-term capital cost recovery*
  - *With no fuel cost, economics of [Capital Expenditures] v. [Operating Expenditures] are very different*[19]
- *Long term commitments must have low regulatory risk to be financeable. This has historically meant contracts rather than tariff rates.*
- *To achieve the greatest efficiency and productivity, any long-term commitment mechanism should incorporate production incentives*

*See*, RENEW presentation *Integrating Markets and Public Policy (IMAPP): Solution Ideas Day*, August 11, 2016 at page 4.

Prior to the recession of 2007-2008, credit conditions appear to have been sufficient for investors to develop renewable resources through the RPS mechanism.[20] More recently, several states have enacted laws authorizing long-term contracts for renewable resources to facilitate financing. This may suggest at least some states believe that the RPS alone, at least as it is currently structured, is insufficient to enable renewable project financing and development of the resource type or scale desired to satisfy state objectives.

The following are some benefits and challenges associated with RPS programs

- *Resource Diversity v. Consumer Costs*

  The RPS mechanism balances investment risk between consumers and project developers. Specifically, RECs are short-term financial incentives: the market price of RECs reflects supply and demand. When the supply of RECs exceeds demand for a

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19 While the quote is attributable to RENEW, see Section V.D. and Figure 8 at 36 below for a discussion and illustration of this and other related issues. *See* also 2015 Mechanisms Whitepaper, Section II.B.3. Fixed vs. Variable Costs at 10.

20 While some commentators have highlighted financing conditions in restructured states for some time, project finance conditions materially changed in 2007-2008. *See* Cory, K. and Swezey, B.G., *Renewable Portfolio Standards in the States: Balancing Goals and Implementation Strategies* (December 2007) at 20-23, available at https://www.nrel.gov/docs/fy08osti/41409.pdf and Schwabe, P. et al., *Renewable Energy Project Financing: Impacts of the Financial Crisis and Federal Legislation* (July 2009), available at https://www.nrel.gov/docs/fy09osti/44930.pdf.

compliance period (typically one year), the market price falls. Similarly, the short-term, transparent electricity and REC market prices signal to renewable resource project developers whether building new resources makes economic sense. As noted above, the RPS mechanism also enables states to consider whether and at what cost to consumers to seek resource type diversity. The RPS mechanisms' ACP is another way that states control consumer cost.

- *New Renewable Resources and Incremental Transmission Infrastructure*

  To date, most of the new utility-scale renewable resource additions in New England, such as on-shore wind, have not required substantial transmission investments in order to interconnect to the transmission system and to be deliverable to consumers.[21] ISO-NE analysis suggests that going forward, adding substantial large-scale renewable resources to the system will require investment in new transmission.[22] When new renewable resources need new transmission to be deliverable to consumers, it materially increases costs and risks. RPS incentives are generally not considered to be able to support new large scale renewable resources that require transmission investment.[23]

- *Changing RPS Programs and Market Price Volatility*

  Some renewable resource developers and investors consider some states' regular changes or proposed changes to states' RPS programs to create uncertainty. These include changes to resource-type eligibility or classes. Some states, for example, consider definitional changes to the RPS program annually. Such changes or proposed changes can affect the estimated profitability of a particular project and introduce financial risk.

  In addition, the short-term market prices for RECs can fluctuate across a wide range from year to year. Combining the risk of regular RPS changes with short-term price volatility can result in challenges to long-term financing of new resources.

- *Lack of Connection Between REC Values and Wholesale Energy Market Prices*

  RECs are created when an eligible resource produces power – one REC for each MWh. Renewable resources may therefore have an incentive to produce electricity to create RECs even when low electric energy market prices are not necessarily signaling a system

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21 ISO New England comments on first U.S. Department of Energy Quadrennial Energy Review (October 10, 2014), at 5, available at https://www.iso-ne.com/static-assets/documents/2014/10/2014_10_10_iso_ne_qer_comments.pdf.

22 *ISO New England Inc. and Participating Transmission Owners Administrative Committee*, Interconnection Process Improvements Filing, Docket No. ER16-946-000 (February 16, 2016), Prepared Testimony of Alan McBride, at 4, 6, 10, and 11, available at https://www.iso-ne.com/static-assets/documents/2016/02/er16-946-000.pdf. *See also* ISO New England comments on second U.S. Department of Energy Quadrennial Review (June 28, 2016) at 6-7, available at https://www.iso-ne.com/static-assets/documents/2016/06/2016_06_28_qer_comments_to_doe_moniz.pdf.

23 This is largely attributable to the same reasons, discussed above, that some states have authorized their transmission and distribution utilities to enter long-term contracts to facilitate renewable and clean energy resource financing. Transmission upgrades also require significant up-front investment, which are commonly recovered over 40 years. Adding transmission costs to the on-shore wind "missing money" estimates resulted in REC prices in excess of the hypothetical future ACP values in many Phase I scenarios.

need for more power. Federal Production Tax Credits provide the same incentive irrespective of any state incentive.

### *E. RPS Implementation Questions*

Some questions to consider regarding the implementation of the RPS mechanism include:

- **Are there structural adjustments to the current RPS mechanisms that would help facilitate financing of new renewable resources?**
  - **Would a minimum and maximum market price for certain types of RECs adequately address price volatility considerations?**
    *Consideration: Allowing prices to "float" anywhere between $0 and the ACP provides the clearest market price signal to resource developers and passes through current market prices to consumers, but may not adequately facilitate financing. Establishing a price "floor" and "cap" (together a "collar") within a smaller range of prices (less than the ACP but higher than zero) may help facilitate financing, but may also mute market price signals.*
  - **Are ACP levels set in a way that will achieve the mix of resources states seek and at the maximum price point states are willing to pay for them?**
    *Consideration: Ensuring that the ACP is set appropriately - balancing costs and objectives - may accommodate more expensive technologies and/or transmission investments that some resources require to compete for RECs.*
  - **Would providing eligibility for a time period long enough to facilitate financing address developer concerns about regulatory risk?**
    *Consideration: Providing (or guaranteeing) revenues for a longer period of time (e.g., eligibility for a premium class or tier for a 7-10 period, then returning to a standard class or tier afterward) may help facilitate financing, but it may also transfer additional investment risk to consumers compared to short-term markets (i.e., one-year).*
- **Would there be benefits from harmonizing eligibility requirements and classification approaches with neighboring states? If so, would those outweigh the benefits a state seeks to achieve by setting its own resource eligibility and classification requirements?**
  *Consideration: Harmonizing eligibility requirements may simplify and thus increase participation for resource developers. The resulting increase in competition can benefit consumers. Harmonizing eligibility requirements may also limit a state's ability to target preferred resource types, sizes, or vintages. Multi-state agreement to harmonize eligibility requirements could also increase predictability and stability that investors favor (relative to the annual consideration of eligibility adjustments). However, as noted above, there is considerable commonality in eligibility requirements across the New England states for wind and solar, the two most common resource types.*
- **Is it useful to align the incentives for electric energy *and* REC production, such that renewable resources receive higher value for RECs produced during periods of high demand in the electric energy market?**
  *Consideration: Differentiating the value of RECs (e.g., on-peak versus off-peak, or during high emission periods, for example) may provide system operation and consumer*

*cost benefits, but may also increase complexity for resource developers and diminish the value of some resources' output.*

- ***To what extent does the link between RPS requirements and load growth negate or otherwise influence the need for new higher cost renewables?***
  *Consideration: RPS requirements typically call for a certain percentage of load to be met by retiring RECs. This allows actionable options such as programs that decrease load – through energy efficiency or net metering, for example – to minimize the need for new renewable resources. To the extent that new renewable resources are increasingly expensive (due to transmission costs, for example) load reduction strategies are a continuing option.*

# IV. Clean Energy Standards

## *A. CES Mechanics*

The CES is a relatively new mechanism that is still being examined and developed within New England.[24] A CES is similar to an RPS: it requires utilities and load-serving entities to purchase an amount of Zero Emission Credits ("ZEC" or ZECs) from eligible resources in proportion to retail load, or pay an ACP. The CES mandate to procure ZECs creates a market for the attributes from resources with zero (or low) carbon dioxide emissions, so-called clean energy resources.

The CES mechanism enables states to compensate resources for attributes that states value *currently*, whether or not states valued a resource's clean energy attributes at the time the resource entered the market. As with an RPS, the minimum price at which a clean energy resource is ideally willing to sell its ZECs is usually the remaining amount of its going forward costs that it does not recover through other electricity markets. A clean energy resource receives the short-term market price for its ZECs; this price may not be equal to its remaining going forward costs. The primary difference between an RPS and a CES is resource eligibility.

A CES is focused on resource types that have beneficial air emission qualities, regardless of whether its fuel source is renewable as defined by existing state law. Two resource types included in this category that are not typically in RPS programs are nuclear resources and large-scale hydropower.[25]

A CES program may operate on its own, as a complement to an RPS, or even incorporate an RPS program. For example, New York is implementing a program that incorporates the RPS into the CES. Specifically, the New York CES will have three tiers: (1) new renewable resources, (2) existing renewable resources, and (3) maintaining certain existing nuclear resources. In New York, the clean energy resources would earn additional revenues from ZECs, but they would not compete with renewable resources in the REC market. Another CES program under development in Illinois creates a market for ZECs and leaves the RPS program separate. The price for ZECs in both New York and Illinois would be initially set administratively, with reference to the social cost of carbon less other electricity market revenues.[26]

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24 The 111th U.S. Congress (2009-2011) proposed four different federal CES proposals and President Obama proposed a CES during his 2011 State of the Union address. None became law. For more information, *see* Brown, P., *Clean Energy Standard: Design Elements, State Baseline Compliance and Policy*, Congressional Research Service R41720 (March 25, 2011). Governor Cuomo directed the New York Public Service Commission to develop a CES in December 2015. On August 1, 2016, the New York Public Service Commission (NY PSC) issued an Order Adopting a Clean Energy Standard (Case 15-E-0302). On February 22, 2017, the NY PSC issued an Order Approving Phase I Implementation Plan. Illinois Governor Rauner signed Public Act 99-0906 in December 2016. The act created Illinois' CES (called a Zero Emission Standard), which took effect on June 1, 2017. The Illinois Power Authority's plan for procuring Zero Emissions Credits was approved by the Illinois Commerce Commission on September 11, 2017. Massachusetts finalized its CES regulations in August 2017.

25 Vermont includes large hydro in its RPS, but is the only state in New England that does so.

26 According to an archived version of the U.S. Environmental Protection Agency ("EPA") website, the social cost of carbon "is a measure, in dollars, of the long-term damage done by a ton of carbon dioxide ($CO_2$) emissions in a given year. This dollar figure also represents the value of damages avoided for a small

Massachusetts' CES, enacted on August 11, 2017, requires eligible resources to be RPS Class I compliant or (1) have low emissions (less than 50% below the most efficient natural gas-fired generator), (2) be located in New England or adjacent control areas and utilize new transmission capacity, and (3) be of 2011 vintage or later.[27]

The market for ZECs only exists in a few states. Illinois' Zero Emission Standard requires 10-year contracts for ZECs between eligible resources and the utilities. The prices and quantities of ZECs would be set administratively each year. New York's CES requires the New York State Energy Research and Development Authority ("NYSERDA") contract for ZECs with eligible resources until 2030. Load-serving entities would then have to purchase ZECs from NYSERDA. New York's CES establishes six, two-year compliance periods. The state would set the price for ZECs in each period. Massachusetts' CES begins in 2018 at 16% of retail electricity sales and increases 2% per year until reaching 80% of retail electricity sales in 2050. RPS Class I compliance counts toward Massachusetts' CES, with a maximum of 13% in 2018 and increasing 1% per year until reaching 45% in 2050.

**Table C: Overview of State Clean Energy Standard Programs**

| State | Clean Energy Standard Details | Zero Emissions Credits |
|---|---|---|
| **Illinois** | 10-year contracts for ZECs between eligible resources and the utilities equal to 16% of 2014 retail electricity sales | ZECs prices start at a price based on the social cost of carbon ($16.50/MWh), but can reduced in proportion to potential increases in an energy and capacity price index[28] |
| **Massachusetts** | Utilities and load-serving entities must procure Clean Energy Credits ("CEC" ~ similar to ZECs) from eligible resources in proportion to retail electricity sales, with the percentage increasing over time (16% in 2018 and 80% in 2050) | Class I RECs and certain energy purchases under 2016 Energy Diversity Act may be used for a portion of compliance, otherwise CECs are priced according to supply and demand |
| **New York** | NYSERDA contracts for ZECs with eligible resources until 2030. Load-serving entities then purchase ZECs from NYSERDA over six, two-year compliance periods | ZEC prices for initial compliance period are equal to $17.48/MWh, then are adjusted every two years in accordance with a formula based on the social cost of carbon |

emission reduction (i.e., the benefit of a $CO_2$ reduction)." January 19, 2017 Snapshot of U.S. EPA Website, available at https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html.

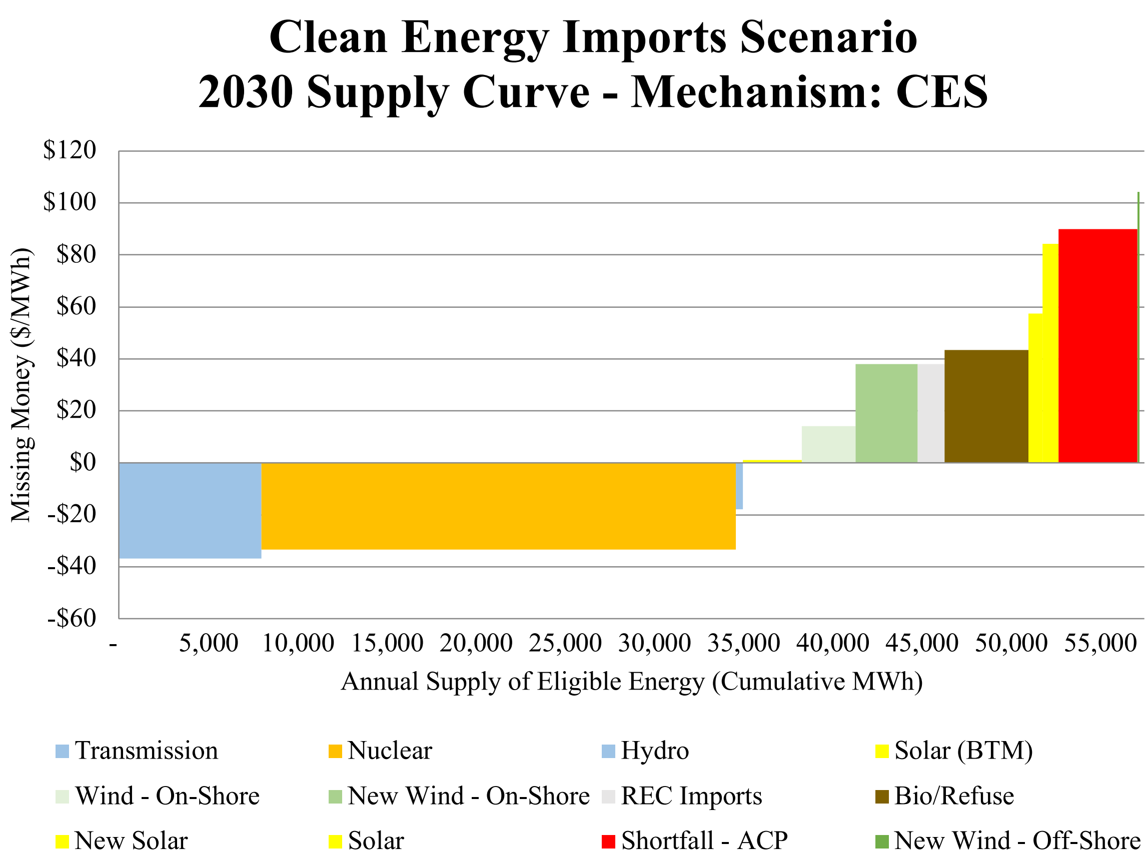
27 For more information on Massachusetts' Clean Energy Standard, *see* http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/ces.html.

28 For more information, *see* the Illinois Power Agency's Zero Emissions Standard Procurement Plan (October 2017), available at https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/Zero-Emission-Standard-Procurement-Plan-Approved.PDF.

### *B.* ***CES Illustration***

The graphic below, Figure 5, presents the aggregated supply of both ZECs and RECs from existing and new clean and renewable energy resources in New England for a hypothetical future year. The graphic includes assumed amounts of *new* renewable resources, assumed *new* clean energy resources (imported hydropower), and output from *existing* clean resources (nuclear) from the Phase I: Scenario Analysis.[29] Figure ___ shows the aggregated supply of ZECs and RECs by price, from lowest price the left to highest price on the right.[30] The price levels in this illustration are equal to the so-called "missing money" amounts estimated in Phase I for this hypothetical future year. Figure 5 also includes an assumed ACP level ($80 in 2025, $88 in 2030).

**Figure 5: Illustration of CES Mechanism**




Similar to an RPS, the market price for ZECs is determined by supply and demand. As shown in Figure ____ above, the "missing money" results from Phase I suggest that some new (imported

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[29] For information, Massachusetts' Clean Energy Standard, 310 C.M.R. 7.75, requires eligible facilities to have commenced commercial operation by December 31, 2010. There are no nuclear facilities in New England that meet this criterion.

[30] The colorful legend under the chart also presents the resource types in order from least cost to highest cost from left to right, continuing in the rows from top to bottom.

hydropower over incremental transmission) and existing (nuclear) resources would earn enough revenues from the energy and capacity markets to more than cover their going forward costs. On the lower left of the graphic, the *new* imported hydropower and *existing* nuclear show a negative value for "missing money". This indicates market-based revenues in excess of costs. In this illustration, which is based on the Phase I analysis, the new and existing clean energy resources would be willing to sell their ZECs for any amount because the resource owners do not need additional CES-related revenues to cover their going forward costs.[31]

Also, Figure 5 above shows that in this hypothetical scenario, the total supply of ZECs from clean energy resources (new imported hydropower and existing nuclear) exceeds the total supply of RECs from new renewable resources. The combination of these two factors suggest that the ZECs from clean energy resources may (1) cost less than and (2) be more plentiful than the RECs from the new renewable resources in this Phase I scenario. If the ZECs and RECs were to compete against one another, the ZECs would appear to have a price and quantity advantage over the RECs.[32]

### *C. CES Design Considerations*

Similar to an RPS, CES programs are designed to support clean and renewable resource types. The classification system, in the form of classes or tiers, can provide different levels of incentives for new and existing resources (i.e., year placed in service or "vintage"). New resources typically require higher financial incentives to enter the market than existing resources require to remain operating. In this way, the classification system can protect consumers from paying both new *and existing* resources the higher amount that new resources typically need. In addition, the classification system can be designed to encourage, or prohibit - depending on state objectives - competition between clean and renewable resources.

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31 Recall that the Phase I analysis is based on power sector modeling under a host of assumptions, which did not include Massachusetts' Sections 83C and 83D procurements. Phase I estimated "missing money" amounts for a range of resource types. "Missing money" estimates in this analysis are resources' remaining going forward costs that are not recovered through forecasted energy and capacity market revenues. Alternative estimates of going forward costs and/or market-based revenues may provide different results.

32 This is largely attributable to the inclusion of imported hydropower over incremental transmission and existing nuclear in this hypothetical illustration of a clean energy standard.

**Figure 6: Illustration of CES Mechanism with Two Tiers**

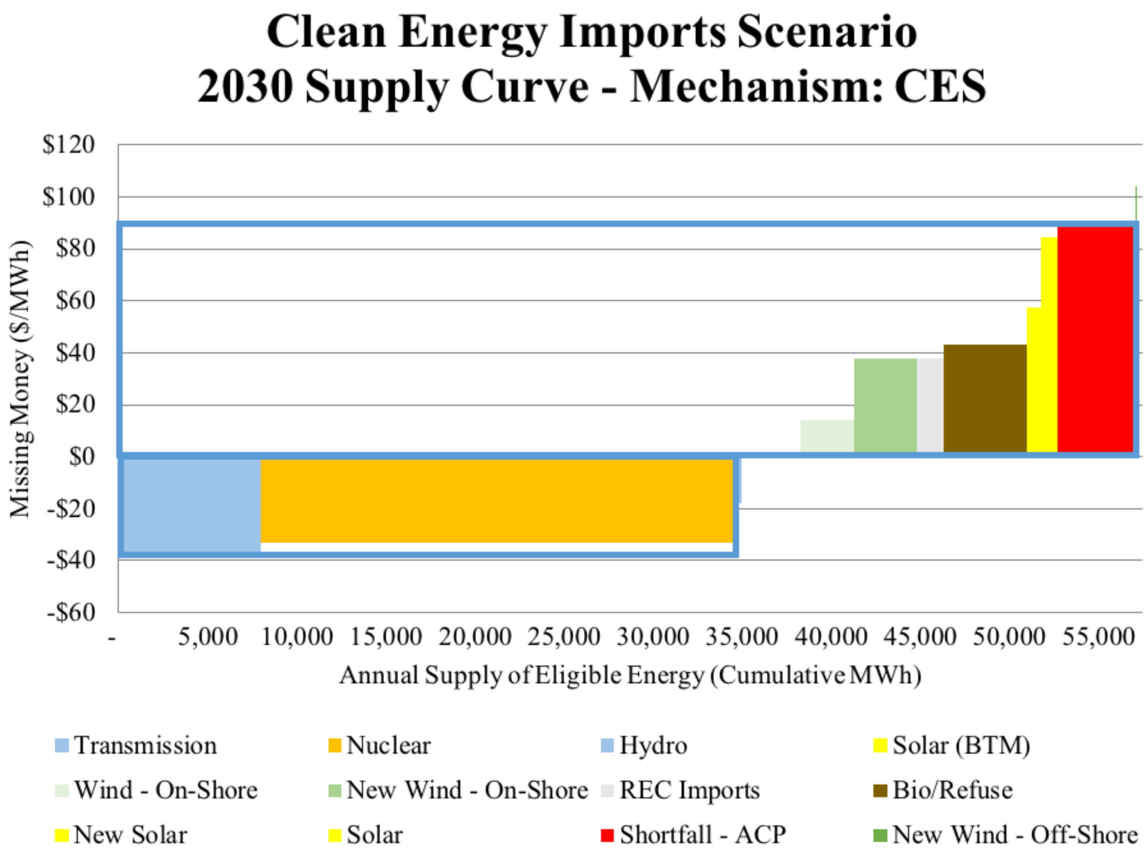


Figure 6 above shows a CES with two classes: (1) on the left, a ZEC Class, and (2) on the right, a REC Class. For simplicity, the demand for ZECs is equal to the available supply and the demand for RECs from new renewable resources is equal to current RPS Class I targets in law. In this hypothetical example, based on Phase I assumptions and "missing money" results, the two-class design protects (1) consumers from paying higher REC prices to lower-cost primarily existing ZEC resources, and (2) the new renewable resources from competing against lower-cost clean energy resources. The CES design presented above creates a new revenue stream for new (imported hydro) and existing (nuclear) clean energy resources without affecting the level of financial support for renewable resources.[33]

An important CES design consideration is the level of demand for a certain class or type of resource. Since the CES can be used to provide incentives for existing resources to remain in operation for a specific period of time, the level of demand may be designed to taper off in a

[33] As shown in Figure 6, the transmission and nuclear resource types earned energy and capacity market revenues in excess of estimated going forward costs resulting in negative "missing money" amounts in Phase I. In this analysis, the ZECs for these resources are assumed to cost $1/MWh. The $1/MWh cost assumption for resources with negative "missing money" estimates is necessary for the relative cost comparison presented below. Otherwise, the negative "missing money" estimates would have skewed the relative cost comparison. $1/MWh is a reasonable proxy for transaction costs associated with participating in the CES program that minimizes the effect of the negative "missing money" estimates for these resource types.

specific and steady manner within a known timeframe. This is sometimes called a "glide path to retirement."

This kind of design - intended to step down support for certain resources until retirement - can overlap with a design that increases demand for other kinds of emerging resources. For example, New York's CES is designed to maintain a portion of its nuclear resources until the year 2030, by which time New York projects renewable resources to be capable of replacing such power.

### *D. CES Benefits and Challenges*

Since there is much less experience with a CES than an RPS, the mechanism's ability to support clean energy resources is relatively untested. However, the CES' similarities to an RPS suggest that a CES would be comparable to in terms of satisfying objectives.

#### 1. Investment Risk Balance

In general, a CES mechanism maintains the current balance of investment risk between consumers and project owners. First, ZECs, like RECs, are *short-term* financial incentives. The market price of ZECs reflects the combination of supply and demand: when the supply of ZECs exceeds demand, the market price falls. Second, the short-term, transparent market prices provide a signal to new and existing clean energy resources whether entry into or retirement from the market makes economic sense.

#### 2. Market Power

The relative benefits and challenges of a CES ultimately depend on its design and the competition between new and existing resources the design is intended to create. To the extent that there are relatively few competitors among new (imported hydropower) and existing (nuclear) clean resources, the exercise of market power can reduce the benefits of a CES. Specifically, if there are only a few existing eligible resources, or new clean resources require substantial transmission development for delivery, then the price for ZECs is likely to be determined by these few resources.[34] Insufficient competition may ultimately limit consumer benefits.[35]

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[34] Two states outside the region base the price of ZECs on the social cost of carbon concept with adjustments reflecting prevailing electric energy and capacity prices. Massachusetts' CES allows Class I RECs and certain energy purchases under 2016 Energy Diversity Act to be used for a *portion* of compliance, otherwise CECs are priced according to supply and demand. This Analysis discusses benefits and challenges of a generic, hypothetical CES. The degree to which market power affects a CES program will ultimately depend on the details of the program and the number of (and competition between) eligible market participants.

[35] "Due to the limited number of qualified sellers of ZECs, in order to protect ratepayers from the exercise of market power, the maximum price that would be paid per ZEC should be administratively set by the Commission and should be updated every year based upon the difference between the anticipated operating costs of the units and forecasted wholesale prices." New York Department of Public Service, *Staff White Paper on Clean Energy Standard*, Case 15-E-0302 (January 25, 2016), at 32, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B930CE8E2-F2D8-404C-9E36-71A72123A89D%7D.

### 3. Similarities to an RPS

Depending on the CES design - classes, resource eligibility and other factors - market fundamentals, and the resource mix, a CES may have many of the same challenges an RPS has in meeting its objectives. Market fundamentals include, for example, the price of natural gas, which affects energy market price levels in New England. To the extent that a CES supports resources that get a significant portion of revenues from the electric energy market, higher gas prices may result in a lower amount of "missing money" that would be recovered through the CES. The CES mechanism enables states to balance resource type diversity with consumer cost impacts. To the extent a CES is designed to financially support *existing* resources, challenges to financing *new* resources may be less important. However, if a CES is designed to provide incentives for resources that require substantial transmission development, the frequent regulatory changes and short-term price volatility challenges discussed above in connection with an RPS may not enable such development. Lastly, a CES incentivizes electricity production even when low electric energy market prices are not necessarily signaling a system need for more power.

## *E. CES Implementation Questions*

Some questions states should consider regarding the implementation of any CES mechanism include:

- **What resource types should be eligible for the CES? What vintages?**
  *Consideration: Allowing resources with low- or zero-carbon dioxide emissions may increase the supply of resources eligible to help states achieve emission reduction goals, but may also provide revenues to resources that have not traditionally been compensated for clean energy attributes and/or may not necessarily have a demonstrated economic basis for state support.*[36] *Allowing older vintages may enable existing resources (nuclear and others) to participate whereas limiting to newer vintages would limit eligibility to only new clean energy projects.*
- **Should existing and new resources compete against one another, or should they be separated into different Classes?**
  *Consideration: Promoting competition between existing and new resources may increase participation and result in consumer cost savings, but supporting existing resources at the same level as new resources may also cost consumers more than existing resources require.*
- **Should a CES mechanism help facilitate financing of new clean resources?**
  - **If so, would a minimum and maximum market price for ZECs provide a sufficiently stable revenue stream and adequately address price volatility considerations?**
    *Consideration: Allowing prices to "float" anywhere between \$0 and the ACP provides the clearest market price signal to resource developers and passes through current market prices to consumers, but may not adequately facilitate financing. Establishing a price "floor" and "cap" (together a "collar") within a*

[36] Existing clean energy resources may have effects on other mechanisms such as, for example, RGGI. Discussion of these interactions are beyond the scope of this Analysis.

*smaller range of prices (above zero and less than the ACP) may help facilitate financing, but may also mute market price signals.*

- **Are there ways to facilitate financing of new resources through eligibility for preferred classes for a time period?**
  *Consideration: Providing (or guaranteeing) revenues for a longer period of time (e.g., eligibility for a premium class or tier for a 7-10 year period, then reverting to a standard class or tier afterward) may help facilitate financing, but it may also transfer additional investment risk to consumers compared to short-term markets (i.e., one-year).*

- **Are there ways to align the incentives for electric energy *and* ZEC production, such that clean resources receive higher value for ZECs produced during periods of higher demand in the electric energy market?**
  *Consideration: Differentiating the value of ZECs (e.g., on-peak versus off-peak) may provide system operation and consumer cost benefits, but may also increase complexity for resource developers and diminish the value of some resources' output.*

# V. Long-Term Contracts

## *A. Long-Term Contract Mechanics*

States have a long history of using long-term contracts to support resources that satisfy public policy objectives. In 1978, the Public Utilities Regulatory Policies Act ("PURPA") created a right for certain qualifying facilities, including renewable resources, to enter into a long-term contract with a utility for its electrical output.[37] As discussed above, since the transition to wholesale competitive markets in the late 1990s, most states have primarily used an RPS to satisfy policy objectives. More recently, some states have authorized their transmission and distribution utilities to enter long-term contracts with certain types of resources.[38]

As discussed further below, long-term contracts are considered able to facilitate the financing of new resources where financial barriers to entry may exist. Long-term contracts typically include the purchase of electrical power *and* its clean energy attributes (e.g., RECs or ZECs).

Prices for these products can be 1) fixed for the contract term, 2) adjusted during the contract term according to a defined schedule, or 3) adjusted dynamically over the contract term by reference to an external factor such as an index to wholesale market prices. Whether the price consumers pay over a contract term is fixed or adjusted influences the placement of risk between consumers and investors and the extent to which consumers will be required to pay above-market costs over-time.[39]

*Terms and Conditions*

In general, a long-term contract is an agreement to transact business under specified terms and conditions. Important terms include: price, quantity, duration, performance, and a pre-determined payment amount and conditions for cancellation. A long-term contract establishes rights and obligations that are legally enforceable.

In this Analysis, long-term contracts are assumed to cover energy, capacity, and renewable or clean energy attributes.[40] The Analysis also assumes that (1) the energy and capacity products will be priced by reference to current market prices and (2) the renewable or clean energy attributes will have fixed prices over the life of the contract.[41] Specifically, the renewable or clean energy attributes are priced at the "missing money" levels for each resource type.

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37 PURPA, Pub.L. 95–617, 92 Stat. 3117, (Nov. 1978).

38 In addition, Vermont is vertically integrated and has had statutory renewable goals since 2005 that encourage its utilities to enter into "affordable, long-term, stably priced renewable energy contracts that mitigate price fluctuations for Vermonters." See, 30 Vermont Statutes Annotated § 8001(a)(3).

39 As discussed further below, long-term contracts are, from time to time, found to be cost-effective relative to forecasted market prices at the time of origination but later turn out to be more expensive than actual market prices.

40 Capacity is included in the analysis to illustrate market-based revenues and related concepts. Some resources that enter into long-term contracts that do not include capacity, but require capacity deliverability, presumably recover capacity revenues through a combination of contracted energy prices and merchant capacity sales.

41 Purchased power can either be used to serve a utility's or load serving entity's customers or resold in secondary markets. Either way, any above-market costs are ultimately collected from its customers. This

### 1. Solicitation and Review Process

In general, distribution utilities subject to state regulatory jurisdiction issue a solicitation (e.g., Request for Proposals or RFP) for renewable and/or clean energy resources. The RFP document details the solicitation process, eligibility requirements, and proposal scoring criteria, among other things. The utilities review and evaluate proposals that developers submit in response to an RFP. Utilities may decide to enter into long-term contracts with certain proposed projects. The utilities then submit these long-term contracts to their state regulatory agency for review. If the state regulatory authority finds the terms and conditions of such long-term contracts consistent with state law (e.g., cost-effectiveness, public interest standards), state regulators may approve the contracts and allow the utilities to recover the contracts' costs from consumers. Most long-term contracts require such regulatory approval before becoming effective as a matter of law.

### 2. State Determinations

Preferences for long-term contracts differ from state to state. Typically, state law defines resource eligibility, the quantity of electrical energy and associated attributes to be procured, and the duration of the agreement. These terms determine the scale and thus the competitiveness of solicitations.

In general, state laws require utilities to demonstrate to its regulatory authority that a proposed long-term contract has benefits for consumers that outweigh its costs to consumers. Cost and benefit considerations vary from state to state. Cost benefit analysis often has some reference to electricity market pricing. This allows states to consider what consumers would likely pay for power absent the proposed contract. Long-term contracts are, from time to time, found to be cost-effective relative to forecasted market prices at the time of origination but later turn out to be more expensive than actual market prices.[42] For this analysis, the *electrical* products under long-term contract - absent the renewable or clean energy attributes - are assumed to be priced at the prevailing wholesale electricity market prices in hypothetical future years. This allows analysis of the long-term contract mechanism to focus on the renewable and/or clean attributes of the power, which may be procured with the electrical products at a combined price that covers the resources' going forward costs.

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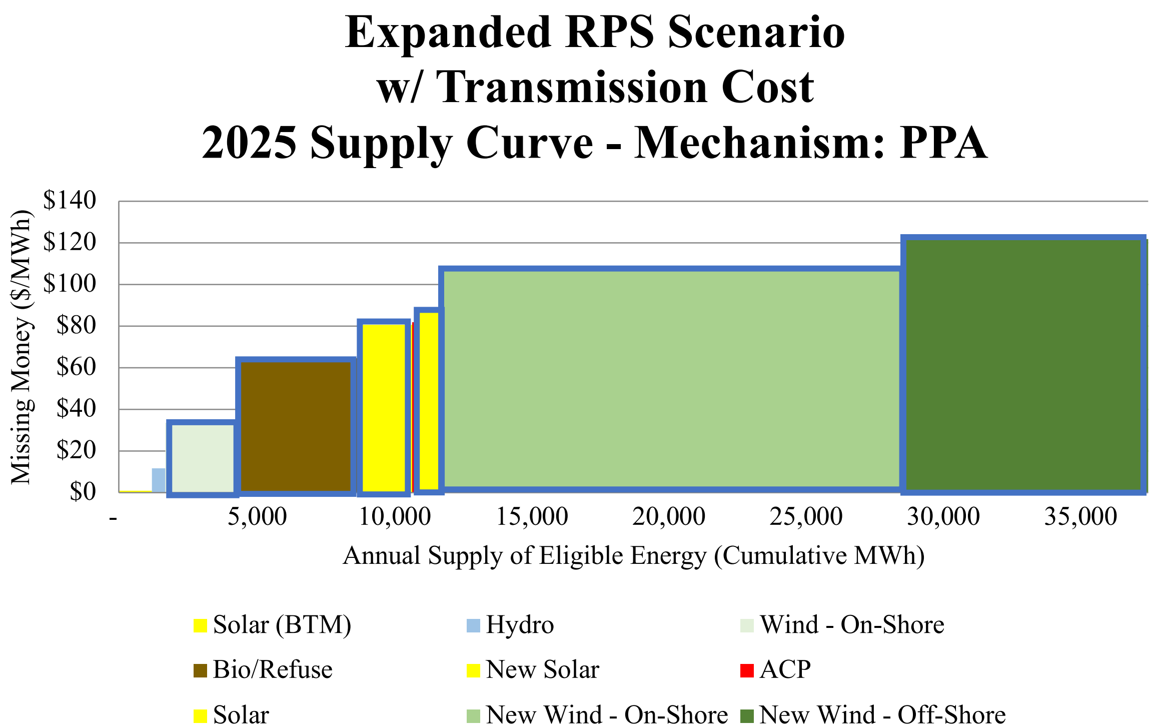
analysis makes the simplifying assumption that all above-market costs are included in the "missing money" estimates. Assuming fixed prices over the life of the contract is consistent with the terms and conditions found in recent power purchase agreements formed to facilitate financing pursuant to state laws. This assumption also illustrates some of the benefits and challenges associated with this mechanism.

42 Purchased power agreements' impact on rates is difficult to assess because of the lack of publicly available data. Reishus Consulting, *New England Electricity Rates Analysis* (September 2015) at 3, available at http://nescoe.com/wp-content/uploads/2015/10/NewEngland_ElectricityRatesAnalysis_Sept2015.pdf. Costs associated with above-market power purchase agreements for certain qualified facilities at the time of electricity restructuring were partially offset by the proceeds of divested utility generation assets. Reishus Consulting, *Electric Restructuring in New England – A Look Back* (December 2015) at 13-14, available at http://nescoe.com/wp-content/uploads/2015/12/RestructuringHistory_December2015.pdf. In some states, costs associated with above-market long-term contracts were significant. *See*, for example, Biewald, B. et al., *Massachusetts Electric Utility Stranded Costs* (November 4, 1997) at 7-8, available at http://www.synapse-energy.com/sites/default/files/SynapseReport.1997-11.UCS_.Massachusetts-Electric-Utility-Stranded-Costs..97-U03.pdf.

### *B. Long-Term Contract Illustration*

Figure 7 below presents long-term contracts in the context of a regional market for renewable and clean energy attributes. Based on Phase I "missing money" results for eligible resources, Figure 7 presents the aggregated supply of attributes from existing and new renewable energy resources in New England for a hypothetical future year for a scenario from the Phase I: Scenario Analysis.[43] Figure 7 shows the aggregated supply of eligible resource output by price, from lowest price the left to highest price on the right. The price levels in this illustration are equal to the so-called "missing money" amounts estimated in Phase I for this hypothetical future year.[44] Figure 7 also shows an assumed ACP level ($80 in 2025, $88 in 2030).

**Figure 7: Illustration of Long-Term Contract Mechanism**




Rather than all resources eligible for the mechanism receiving the prevailing "market price" (like RPS and CES above), a long-term contract only pays those resources selected an amount equal to the "missing money" for its resource type.[45] To show a host of long-term contracts with each eligible resource in the region, Figure 7 above presents a range of prices that are paid to each

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43 In this scenario, *Expanded RPS Scenario w/ Transmission Cost*, the cost of transmission to enable delivery of new on-shore wind resources is included in the missing money estimates.

44 Recall that in this analysis, long-term contracts include energy, capacity, and attributes, thereby leading to a total contract price that is higher than just the "missing money." However, energy and capacity products are assumed to be valued at market price, allowing the analysis to focus on "missing money" estimates as the basis for mechanism costs. Costs associated with the Long-Term Contract mechanism in this analysis are based on such "missing money" estimates.

45 This illustrative analysis assumes away project-specific differences among resource types, among many other things.

resource type. Long-term contracts pay a resource-specific price determined at the time the contract is entered. The long-term contract prices informed by Phase I "missing money" estimates remain stable over the study period, regardless of whether actual future electricity market revenues or going forward cost estimates change.

### *C. Long-Term Contract Design Considerations*

Long-term contracts are designed to support resources states desire. Most often, there is an emphasis on facilitating financing for new renewable and clean energy resources. States may customize long-term contracts in a number of ways. Contract eligibility may be determined by:

- resource technology type;
- air emissions characteristics;
- initial year of commercial operation (vintage); and/or
- amount of instantaneous output capability (e.g., capacity).

Long-term contracts can also accommodate a variety of products, including electrical products (e.g., energy, capacity, or both), attributes (e.g., RECs and ZECs), or combinations of those.

From a resource's perspective, long-term contracts provide price certainty or relative predictability over a period of time for electricity products and associated attributes. Such price certainty or relative predictability can be viewed as a form of insurance against volatile short-term market prices. A long-term contract may also provide insurance (also called a "hedge") against the risk of low market prices, depending on how a state structures a contract.

From a customer's perspective, a long-term contract may provide certainty about renewable or clean energy attributes and insurance against the risk of high and/or volatile market prices depending on how a state structures a contract (on the other hand, contracts may also require customers to pay costs that exceed market prices over the contract term). Whether customers get the value of any insurance against the risk of high prices depends on whether the electricity price and attribute forecasts turn out to be accurate over the contact term. In cases where the utility or state forecast of future electricity market prices is not accurate or where the actual market value of renewable power from the contracted resource drops over the contract's term, consumers may pay more for the same power and/or attributes.[46]

Some long-term contracts do not include the electricity market product known as capacity - the obligation to be capable of providing electric energy anytime within a specified commitment period. Whether states include capacity in a long-term contract depends on several considerations. These may include the targeted resource types, their general physical location in relation to the transmission system, and the associated economics.[47]

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46 "[L]ong-term estimations of avoided costs are persistently above-market and, the longer the contract term, the greater the disparity." Post-Technical Conference Comments of the Connecticut Public Utilities Regulatory Authority and the Massachusetts Department of Public Utilities, *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Docket No. AD16-16-000 (November 7, 2016) at 7, available at https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14393930.

47 To the extent a long-term contract includes capacity, there are several legal considerations as well, including how the transaction fits within a FERC-jurisdictional wholesale market. *See Hughes v. Talen*

One reason that capacity is sometimes *not* included in long-term contracts is because a specific resource type's production characteristics and associated transmission system issues make capacity very expensive. For example, on-shore wind resources produce power when the wind is available and not necessarily when customer demand for electricity is high. During the summer, when customer demand reaches its highest point of the year in New England, on-shore wind resources tend to produce a relatively small fraction of their potential capability. Moreover, on-shore wind resources in New England tend to be located in an area of the system that runs out of transmission space from time to time. Accordingly, new on-shore wind resources tend to provide relatively little electric capacity and may require substantial transmission investment to be deliverable and able to provide capacity. In those cases, including capacity in a long-term contract for new on-shore wind may not be economically justified for a single utility's or state's customers. On the other hand, *not* including capacity in a long-term contract would increase costs consumers pay to ensure an adequate supply of resources over the longer term. Additionally, if the contributions that resources under long-term contracts make to resource adequacy are not counted in the wholesale electricity markets, those markets may buy too much capacity.[48]

Requirements related to the location of eligible resources are another important long-term contract design consideration. Legal challenges may arise in connection with requiring resources to come from a specific location, such as within a certain state. Most long-term contracts in New England, however, describe locational requirements in terms of being capable of being delivered into the ISO-NE system. In practice, this generally means resources are located within New England or adjacent electricity systems. To address transmission bottleneck concerns, many long-term contracts specify a location on the transmission system to which the power must be capable of delivery. Such delivery location requirements may enable equitable comparisons of prices among competing projects originating in different places.

### D. *Long-Term Contract Benefits and Challenges*

In some states, long-term contracts have been a key mechanism through which to provide economic incentives for renewable and clean energy resources and enabled their financing. In some respects, contracts are a component of the electric industry's risk management: within the competitive wholesale market structure, competitive suppliers and municipalities regularly use contracts with various resources to mitigate (or hedge) energy price risk.[49] Contracts in general

*Energy Mtkg., LLC*, 136 S.Ct. 1288 (2016). Importantly, the Supreme Court expressly limited its holding in *Hughes*, finding that states were not "foreclosed from encouraging production of new or clean generation" as long as those "measures . . . do not condition payment of funds on capacity clearing the [FERC-jurisdictional] auction." *Id.* at 1298.

48 "If renewable resources are being built, but are not reflected in the FCM, then the FCM may send an incorrect signal to construct new capacity that is not needed. Not only would the capacity market send an incorrect signal, but customers would have to pay for capacity twice – first, for renewable resources via out-of-market mechanisms and second, for additional capacity that is procured because the capacity market has sent the incorrect signal that additional capacity is needed." 158 FERC ¶ 61,138 at P 9 (2017).

49 Competitive suppliers tend to transact in shorter-term contracts, on the order of five years or less. In this analysis, the Long-Term Contract mechanism is assumed to be in the 10-15 year range of contract duration. Contracts entered into pursuant to state implementation of PURPA are beyond the scope of this analysis.

change the balance of risk between investors and consumers. The length of the contract can amplify the risk. Some argue that such a shift in risk indirectly and adversely affects electricity market economic incentives. Others assert that this mechanism allows states to pick winners and losers among projects, rather than letting winners emerge through the competitive wholesale markets.[50]

Long-term contracts provide a degree of revenue certainty or relative predictability for the renewable and clean energy resource owners that obtain contracts for specific projects. New renewable and clean energy resources have relatively high capital costs (on a dollar-per-kilowatt basis) compared to more traditional resources (i.e., fossil fuel-fired resources). This requires project developers to invest more dollars up-front and increases the risk profile of these investments, assuming all other factors are consistent (e.g., interest rates, debt-to-equity financing ratio, etc.). Long-term contracts that specify prices for a 10-15 year period let project developers mitigate some of the additional investor risk associated with the relatively higher up-front costs of new renewable and clean energy resources by shifting that risk to consumers over the contract term. Long-term contracts also help address frequent regulatory change risk and short-term price volatility risk for investors by transferring some risk to consumers. Accordingly, this mechanism better facilitates financing for new resources. To the extent that long-term contracts help a developer obtain lower cost financing, some portion of the resulting savings may be reflected in the contract price.

Figure 8 below presents the cost of new on-shore wind resources compared to new natural gas-fired resources. The values are based on recent analysis conducted by a consultant to ISO-NE for use in the Forward Capacity Market ("FCM").[51] Figure 8 illustrates that (1) renewable resources cost more than traditional resources (on a dollar-per-kilowatt basis) and (2) energy market revenues and the value associated with renewable energy attributes contribute a significant portion of necessary revenues. In the illustration, the comparatively higher cost on-shore wind resources place additional investment capital at risk and have difficulty competing with natural gas-fired resources for capacity revenues.

In the FCM, new resources can lock-in the market clearing price for their first seven years of operation. Assuming, for example, that natural gas-fired resources can lock in their offer price for seven years, this will guarantee approximately 20% of a project's total cost over 20-year period. In contrast, an on-shore wind resource that could also hypothetically lock in its offer

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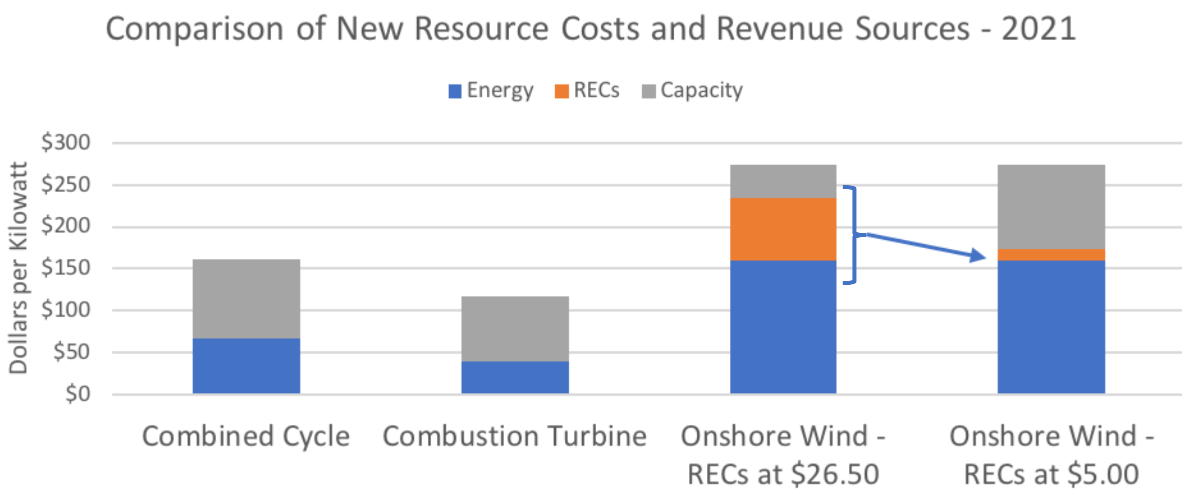
50 The degree of competition, existence of barriers to entry and exit, and topics including the incorporation of societal externalities in the wholesale markets are beyond the scope of this paper.

51 Concentric Energy Advisors, ISO-NE CONE and ORTP Analysis: An evaluation of the entry cost parameters to be used in the Forward Capacity to be held in February 2019 ("FCA 12") and forward (December 2, 2016) and associated electronic workbooks, available at https://www.iso-ne.com/committees/markets/markets-committee/?eventId=128636. Figures presented are based on the ORTP workbook and associated assumptions and include the value of federal production tax credits for renewable resources. Actual project financing values may differ from the presented figures – the ORTP assumptions are designed to represent the low end of the competitive range. Discounted project cash flows have been normalized for project size by proxy unit nameplate capacity values.

price for seven years would only guarantee approximately 5% of the project's total cost over a 20-year period.[52]

**Figure 8: Investment Risk, Energy Resources in a Capacity Market, and Attribute Values**




The third and fourth columns also show the contribution of renewable energy attributes at two different assumed price levels. Figure 8, above, indicates that when the price of RECs falls, on-shore wind resources must earn additional revenues from other sources, in this case the capacity market, to cover its costs. Accordingly, short-term price volatility – especially for energy, and renewable energy attributes – significantly affects on-shore wind resources' financial viability. Long-term contracts hedge investment and price risks for investors, making those projects easier to finance. This is due to the shift in risk to consumers.

### 1. Risk Allocation

The movement to wholesale competitive markets was, in large part, intended to shift investment risks away from electricity consumers and toward private investors.[53] The costs of long-term contracts are generally recovered from consumers through electric distribution bills, which places some risk back on electricity customers. When investors hedge their investment risk through long-term contracts with consumers, it may result in lower financing and development costs associated with new renewable resources. This may provide some consumer savings associated with achieving the requirements of state laws. At the same time, while designed to

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52 This hypothetical assumes that the generic combined cycle, combustion turbine, and on-shore wind resources in the ORTP analysis receive their ORTP values from the FCM for the first seven years of commercial operation. The on-shore wind ORTP value is higher than the combustion turbine and combined cycle's ORTP values, making the likelihood of on-shore wind receiving this value from the competitive FCM quite low. In addition, renewable resources that use the Renewable Technology Exemption to the Minimum Offer Price Rule are not eligible to receive the seven-year price lock. The seven year price lock is discussed here to emphasize the relative contribution of capacity revenues to two different types of resources.

53 *See* Reishus Consulting, *Electric Restructuring in New England – A Look Back* (December 2015), at 7, available at http://nescoe.com/resource-center/restructuring-dec2015/.

achieve a range of state objectives, some market participants and other have cited to these long-term contracts as being in tension with competitive wholesale markets that seek to select resources with the lowest costs for consumers over time.[54]

Whether long-term contracts save or cost consumers money over time depends in large part on assumptions, other analysis, and contract provisions. For example, a 2007 report to the U.S. Congress a from an inter-agency task force of employees from the Department of Justice, Federal Energy Regulatory Commission, Federal Trade Commission, Department of Energy, and Department of Agriculture on competition in wholesale and retail markets found,

> To encourage renewable and alternative energy generation, several states, including California, New York, Massachusetts, Maine, and New Jersey, required utilities to sign long-term contracts with [qualified facilities under PURPA] at prices that eventually ended up being much higher than the utilities' actual marginal savings of not producing the power itself (avoided costs). As a result, many utilities in these states entered into long-term purchase contracts at prices higher than those available in the competitive wholesale markets. The costs of these [qualified facility] contracts were reflected in retail rates as cost pass-throughs. The experience added to the dissatisfaction with retail rate regulation.[55]

### *E. Long-Term Contracts Implementation Questions*

Some questions that states should consider regarding the implementation of the long-term contract mechanism include:

- **What resource types should be eligible for long-term contracts?**
  - **Are the fuel type (i.e., renewable) and air emissions characteristics (i.e., clean) the primary criteria?**
    *Consideration: Focusing on renewable and clean energy resources may help states achieve emission reduction and resource diversity objectives. Other criteria like employment benefits, tax revenues, or operating characteristics may provide broader economic or societal benefits. Additional and diverse criteria may make project selection more complicated.*
  - **Is the objective to facilitate the financing of new resources or to maintain economic viability of existing resources?**
    *Consideration: Facilitating financing for new resources may require a longer-term, stable, and comprehensive commitment and indicate the need for project milestone completion conditions. Maintaining existing resources may*

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54 For example, *see* the comments submitted in the FERC's proceeding on *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000. *See* also, *Clark, A., Regulation and Markets: Ideas for Solving the Identity Crisis* (July 2017), available at http://wbklaw-com.securec23.ezhostingserver.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf.

55 Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, Pursuant to Section 1815 of the Energy Policy Act of 2005 (April 2007), at 21, available at https://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf.

*be better suited toward shorter-term arrangements that states can revisit more frequently in light of remaining financial need and market prices.*

- **What products should be included in a long-term contract?**
  *Consideration: Including energy, capacity, and attributes can help states achieve more predictable electricity costs and meet energy security and/or emission reduction goals, but transfers additional investment and/or market price risk to customers.*[56] *Energy and capacity products also need to be included in a manner consistent with federal law.*[57] *Including fewer products (just energy and attributes, or only attributes) distributes these risks back to the resource and may result in higher long-term contract rates while still meeting state objectives.*
    - **How much electric power and/or associated attributes will meet the state's objective(s)?**
      *Consideration: Contracting for larger amounts of power may enable economies of scale to reduce prices and/or increase competition among resources, but may also limit competition, and concentrate investment or price risk in larger projects or procurement cycles. For example, some larger resources may have lower per-unit costs due to economies of scale. To the extent that such larger resources are relatively few in number, the trade-off may be to procure fewer, larger resources rather than more, smaller resources. Smaller power purchases may diversify such risks, but not support larger resources that may be required to meet policy objectives.*
- **What is the appropriate length of time for the long-term contract?**
  *Consideration: Longer terms (10-15 years for example) provide price certainty and revenue stability, and may facilitate better financing terms, but transfer more risk to consumers as it may limit a state's ability to adjust terms over time to protect consumers from paying prices well above market, for example. Shorter terms may enable states to adjust contractual commitments based on then-current prices and costs or technology advancements, but may be inadequate to facilitate financing. Risks associated with the timing of the business cycle may be present under long- or short-term agreements.*
- **What are the indirect impacts on other existing mechanisms and/or wholesale electricity markets?**
  *Consideration: Increasing amounts of long-term contracting may help address policy objectives that wholesale electricity markets are not today designed to achieve, but may also affect price levels for buyers and sellers in competitive wholesale markets.*[58]

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56 Energy security is one of the policy objectives for pursuing renewable resources that are not dependent on imported sources of fuel. For an additional discussion of energy security policy objectives, *see* 2015 Mechanisms Whitepaper at 3, 5-6, especially fn. 12.

57 *See* n. 44 above. *See also* 2015 Mechanisms Whitepaper at 35-37.

58 The Federal Energy Regulatory Commission has focused on so-called "price formation" issues since 2014. For more information, see https://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp.

> *Increasing levels of long-term contracting may also affect supply and demand for other mechanisms to support public policies such as an RPS or CES.*[59]

[59] "In Massachusetts, amendments to the Green Communities Act establish a pathway to competitively securing contracts for 1,600 MW of offshore wind and up to 9,450 GWh of hydroelectric and Class I renewable energy through a competitive process. Fulfillment of this authority without corresponding increases in RPS demand targets would specify long-term market surpluses, and REC prices less than $5 per MWh once these resources are expected to come on-line in approximately 2023." (parenthetical in original omitted) Knight, P. et al., *Analysis of Massachusetts Electricity Sector Regulations: Electricity Bill and CO2 Emissions Impacts* (August 2017), at 17, available at http://www.mass.gov/eea/docs/dep/air/climate/3dapp-study.pdf.

# VI. Strategic Transmission Investments

## *A. The Objective of Strategic Transmission Investment*

The term Strategic Transmission Investment is used in this paper to describe transmission investments funded pursuant to a decision by one or more states to enable generating resources that can satisfy state requirements to interconnect to the transmission system. To date, New England states have not used Strategic Transmission Investment as a means to support such resources; however, New England consumers have paid the costs of generator interconnections indirectly through long-term contracts with certain resources pursuant to various state laws.

## *B. Approaches to State Transmission Funding in New England*

There are three ways that New England state officials could pursue a Strategic Transmission Investment:

1. Choosing to fund an Elective Transmission Upgrade ("ETU") through a long-term contract.

2. Identifying needs in the ISO-NE Order 1000 Public Policy transmission planning process which could result in ISO-NE selecting a Public Policy Transmission Upgrade ("PPTU").

3. Relying on the traditional method of reimbursing generators for the costs of interconnecting to the transmission system through long-term contracts with distribution utilities.

In each of the three methods, ratepayers ultimately pay the costs of transmission upgrades.

### 1. Elective Transmission Upgrades

#### a) Mechanics

An Elective Transmission Upgrade is a transmission project that a project developer independently funds on its own behalf or on behalf of another market participant and is interconnected to the ISO-NE system. ETUs are always paid for by the developer and never through the ISO-NE tariff, but the ETU developer has options for how the project is funded. It can fund the upgrades itself by raising debt and/or equity, or through an agreement with a generator or an importer, or potentially through a state-sponsored contract. Examples of ETUs that are currently in the queue include multiple projects to import hydro from Canada or to transmit power from Northern Maine to Southern Maine. As these examples reflect, the ultimate purpose of the ETU in this context is bringing generation to market.

A request to interconnect an ETU goes through ISO-NE's interconnection queue, the same queue that is used for generation interconnections. This queue is generally processed by ISO-NE on a first come-first served basis, meaning that projects are studied in the order in which they have submitted their interconnection requests. As discussed in more detail below, ISO-NE has recently implemented a new methodology to study generation interconnections that are located in close proximity with common upgrades in a single group study known as a cluster study.[60] ISO-NE also recently made changes to its transmission tariff to allow ETUs to partner with resources looking to interconnect. Under this approach, the ETU and the generator both must elect this treatment in their initial interconnection requests. The ETU and generator arrangements would be a private agreement between the two entities.

To use an ETU as a Strategic Transmission Investment, an ETU would be selected through a state process, perhaps through an RFP. One or more states would agree to fund the project through rates charged to that state's consumers, possibly through a long-term contract with the ETU. The specific mechanics of such funding would be at the direction of the state through a means that conforms to its laws and authorities. ETUs have entered bids into recent state sponsored RFPs, usually partnered with generation resources.

Alternatively, it is possible that a state could partner with entities to design an ETU independently of an RFP, and work with a transmission developer to move a project through the queue process. This has not yet been done so the specifics would have to be worked out.

In any case, since ETUs are participant funded, the developer must be paid outside of the ISO-NE tariff. That payment could, for example, be in a contract with a generator, or a utility purchasing energy (and any related attributes, such as RECs) and delivery of that energy from a generator under a long-term contract pursuant to a state process. As an ETU has not yet been funded through a state mechanism, the details of how this would work have not been developed.

#### b) Benefits of ETUs

One benefit of the ETU approach is that state-supported transmission has an option to be tied directly with a specific generation facility for interconnection purposes as described above. While this ensures that the generator can interconnect, it confers no rights to flow power, or use the transmission line.[61] Transmission priorities or reservations do not exist in internal New England power flows. New England's internal dispatch is based solely on the lowest cost unit that can reliably meet demand.

A second benefit is that the ETU could possibly assume some of the risk associated with cost over runs, depending on contractual terms. In this case, consumers could be protected from cost increases.

A final benefit of this approach is that a state can select the specific transmission project it wishes to build to satisfy its objectives. This would be possible whether a state selects the ETU in an RFP, either standalone or partnered with generation through an RFP, or if a state chooses to partner with others to design an ETU. An ETU is the only approach that gives a state that level of

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60 Rather than processing interconnection requests individually and serially, it may be more efficient under certain circumstances to process a group of requests together in a so-called "cluster." For more information, see *ISO New England Inc.*, 161 FERC 61,123 (2017), available at https://www.iso-ne.com/static-assets/documents/2017/11/er17-2421-000_order_accept_interconnection_queue_clustering.pdf.

61 For example, non-incumbent developers of new, cost-based, participant-funded transmission projects may "select a subset of customers, based on not unduly discriminatory or preferential criteria, and negotiate directly with those customers to reach agreement on the key rates, terms, and conditions for procuring up to the full amount of transmission capacity" when developers make certain demonstrations regarding a fair, open, and transparent process. 142 FERC ¶ 61,038 (Jan. 2013).

control over a project developed to advance that state's law. An ETU allows a state to make its own evaluation of the benefits and risks of the project that it selects.

#### c) Challenges of ETUs

How a state might fund an ETU could depend on its authority and/or preferences. The simplest method could be for the generator to sign the contract with the ETU, and for the purchasing utility to backstop the cost and pass those costs on to ratepayers pursuant to a regulatory order. Alternatively, the purchasing utility could sign a contract directly with the ETU which would also be paid for by ratepayers.

#### d) Who bears the risk?

Utility ratepayers bear the risk. If the generator is not built, subject to any contractual or other remedies, consumers would still pay for the transmission even if no power flows over the new line. Also, theoretically, once a new transmission line exists, a new generator could interconnect and use the line, but there is no guarantee that the new generator would be the resource type that a state sought to support. Subject to contractual terms or other remedies, it is possible that ratepayers could assume the risk of paying for a transmission line that ultimately flows no power and provides no benefit.

### 2. Public Policy Transmission Upgrades (PPTUs)

#### a) Mechanics of PPTUs

ISO-NE's Tariff includes a process for states to identify public policy needs that may drive transmission investment. Through this process, a state could choose to identify a need for ISO-NE to study. This could potentially result in ISO-NE identifying and selecting a transmission solution. The costs of PPTUs are passed through the ISO-NE billing system. Under a default allocation of costs that the Federal Energy Regulatory Commission ("FERC") approved, 30% of costs are allocated to the state(s) with the identified need, and 70% of costs are allocated to all load in New England on a load ratio share basis. However, because this is the *default* cost allocation, one or more states or others could propose a different sharing of costs for a specific project(s) subject to FERC review and approval. A PPTU is the only method listed in this paper that includes a mechanism to allocate transmission costs to consumers in states other than the state that has an identified policy need.

#### b) Benefits of PPTUs

A major benefit of PPTUs is that transmission projects developed through this path do not have to go through the interconnection queue process. Since the ISO-NE's interconnection queue is first come, first serve, and has been backlogged for years in Maine, avoiding the queue has material development advantages. PPTUs are therefore able to be designed and developed more quickly than other interconnection-related upgrades.

Another benefit from the perspective of a state that desires the upgrade is that a portion of the project's costs are socialized across the region, absent other agreement. Conversely, states with no public policy need could view such socialization as adverse to their consumers' interests.

### c) Challenges of PPTUs

The PPTU process is new and relatively untested in New England. A PPTU requires ISO-NE to issue an RFP for projects that can solve the identified need. To date, ISO-NE has no experience with such RFPs.

Another challenge, from a state perspective, is that the FERC-approved tariff authorizes ISO-NE to select the PPTU identified as meeting a state policy need without any formal role for the states in that process. While states may provide input to ISO-NE prior to such a selection, the tariff provides no assurance that the project ISO-NE selects would be viewed by the relevant state(s) as a reasonable or proper solution to a state policy need.

Further, as noted, another challenge to the PPTU process is that it has the potential to require consumers in a state that has already satisfied its public policy objectives to fund those of another state. This provision could lead to extensive litigation and substantial delays to the proposed project.

### d) Who Bears the Risk?

All ratepayers in New England may potentially shoulder the costs of PPTUs. The risks are mitigated by the fact that the Tariff provides states a role in the initial identification of federal or state policies driving transmission needs. Also, to the extent a need is identified, the tariff allows for ISO-NE to conclude the process before an RFP is issued and provides ISO-NE with additional discretion not to select a project once the RFP has been completed. In addition, the tariff allows for a different allocation of costs among states than the default method, which would spread some costs across all states.

## 3. Traditional Indirect Funding of Transmission Upgrades

### a) Mechanics

Under the traditional method of funding transmission, a generator requests interconnection from ISO-NE and enters into a contract to pay for needed upgrades. Specifically, the generator enters into a contract with a utility to sell its output subject to state regulatory review and approval, as discussed in section V above. The cost of the interconnection related upgrades is likely to be included into the price of the power that is sold. Resources with lower interconnection costs would be able to sell their power at lower prices. Those with more expensive interconnections will offer higher priced power.

Recently, ISO-NE has developed a new methodology to study generation interconnections in clusters and is currently applying it to wind generation in Maine. The technical aspects of this kind of interconnection are much more complicated and expensive than single project interconnections, but the contract to interconnect would still be signed by the interconnecting generator and presents no change to how the money would flow. Who pays for the upgrades is not changed by the cluster proposal: generators are still responsible for paying for all their costs to interconnect. No charges from the cluster enabled upgrades will be charged directly to customers.

#### b) Benefits of this approach

The approach is straightforward and well established for resources (with the exception of clusters, described above).

#### c) Challenges of this approach

If the interconnection is too complicated or expensive for the generator to fund on its own, the project does not move forward. Arguably, if a project terminates because it cannot afford an interconnection, it is the right economic outcome.

While other transmission operators in other regions have experience successfully implementing interconnection clusters, ISO-NE does not. Experience will determine how well it enables projects in the cluster to more easily interconnect.

Upgrades to interconnect resources in the Maine cluster area are very expensive.[62] While studying the resources together in a cluster helps by allowing the costs of common upgrades to be shared, it does not change the fact that transmission/interconnection is typically very expensive.

#### d) Who bears the risk?

The generator bears all of the risk as the process is currently structured. A state could consider whether it wished to assume any of that risk by a contract or some other means within its authority.

### C. *Strategic Transmission Investments Design Considerations*

The Phase I analysis assumed hypothetical transmission expansion to enable delivery of new on-shore wind.[63] Cost for this transmission was presented in two ways: (1) through some means outside of its contract such as the Strategic Transmission Investment described above, and (2) through investment by the new on-shore wind resources through their interconnection in the traditional manner.

The Phase I analysis also included a No Transmission Scenario that examined the implications of New England choosing not to build the transmission necessary to deliver new on-shore wind power to customers in New England. The No Transmission Scenario provided information about the economic impacts of transmission constraints and associated resource curtailment.

The hypothetical transmission upgrades from Phase I were sized to enable delivery of 3,600 MW of new on-shore wind resources from Maine to the center of the transmission system in

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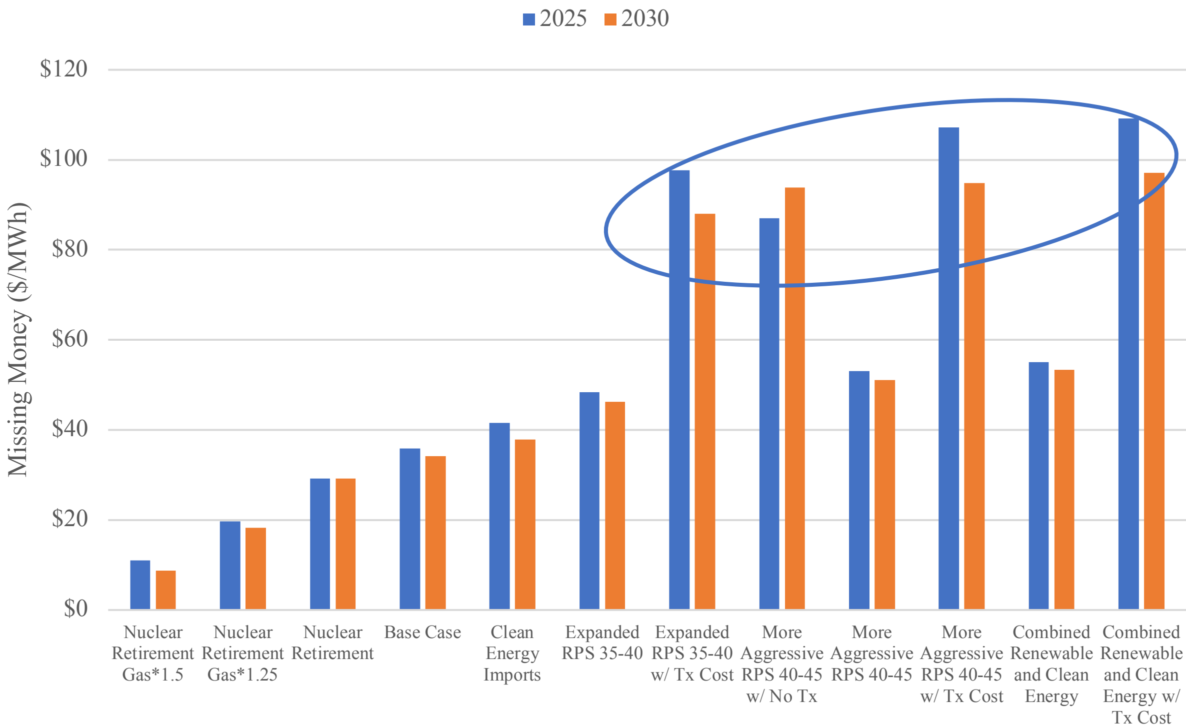
[62] ISO-NE's recently completed Maine Resource Integration Study identified upgrades totaling $1,830.9 million, to interconnect 1,895 MW of wind generation in Northern and Western ME on an energy only basis, i.e., the resources would be able to produce and sell energy, but would not be allowed to sell capacity into ISO-NE's capacity market.

[63] The Phase I analysis also assumed additional solar PV and off-shore wind resources. The assumed hypothetical resources are generic and *are not related to any particular project* that may be the subject of any pending or future solicitation process.

Massachusetts. These three hypothetical upgrades are estimated, at a very high level, to cost approximately $5.7 billion.[64]

Figure 9 below from the Phase I analysis highlights the impact of transmission and associated cost responsibility on the "missing money" for *new* on-shore wind resources. The oval on the graphic spotlights how large the cost of transmission upgrades is for this type of resource, how much the needed contract price would rise if the cost was imbedded in the contract, and the impact that transmission investment, regardless of how it is paid for, has on the resource's economics and the amount of "missing money" that is recovered through other mechanisms.

**Figure 9: New On-Shore Wind Resources' "Missing Money" Estimates Across All Scenarios in 2025 and 2030**




Specifically, the Expanded RPS 35-40, More Aggressive RPS 40-45, and More Aggressive RPS 40-45 w/ Tx Cost Scenarios assumed adequate transmission has been built (the model included sufficient transmission) to deliver new on-shore wind energy. The results for these scenarios are presented in two ways:

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64 The More Aggressive RPS 40%-45%'s hypothetical 3,600 MW high-voltage direct current (HVDC) transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $5.7 billion. On an annual basis, this would equal approximately $911 million. Charging the costs of the transmission to the new on-shore wind resources in the Expanded RPS 40-45 Scenario adds approximately $44-$54/MWh to the "missing money" for this resource type. See Appendix A of the Phase I report for more information. Similarly, the Expanded RPS 35-40's hypothetical 2,400 MW HVDC transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $3.8 billion. On an annual basis, this would equal approximately $611 million. Charging the costs of the transmission to the new on-shore wind resources in the Expanded RPS 35-40 Scenario adds approximately $42-$49/MWh to the "missing money" for this resource type.

> (1) assuming the costs of transmission for new on-shore wind resources are paid for outside the power contract, as either an ETU or PPTU; and
>
> (2) assuming the costs are paid by the new on-shore wind resources as part of their interconnection agreement and added to the "missing money" for new on-shore wind resources.

Presenting the results this way highlights how generators paying for transmission costs almost doubles the "missing money" for new on-shore wind resources. This is because the "missing money" calculation for this resource includes both generation *and* transmission costs. Importantly, **if new on-shore wind resources pay for the transmission costs needed to interconnect their resources, their "missing money" will be in excess of assumed future ACP levels ($80 in 2025 and $88 in 2030)**.

Alternatively, in the No Transmission Scenario, ISO-NE system operators would have to curtail (turn off) new on-shore wind due to transmission constraints. Turning off new on-shore wind resources because of transmission constraints also results in higher "missing money" estimates for new on-shore wind (compared to the Expanded RPS and More Aggressive RPS Scenarios, which assume additional transmission). This is because transmission constraints prevent new on-shore wind energy from delivering energy and that reduces energy market revenues. Indeed, under the study's assumptions, **the lack of associated transmission to enable deliverability almost doubled the "missing money" for *both* new and existing on-shore wind resources**. This is because both new and existing on-shore wind resources are mostly located in the same portion of the system. The transmission constraints that impede new on-shore wind would also adversely impact existing on-shore wind resources.

### *D. <u>Strategic Transmission Investments in Other Areas of the Country</u>*

As mentioned above, Strategic Transmission Investments have yet to be tested in New England. However, some single-state electricity systems have used variations of Strategic Transmission Investment. Southern California Edison's Tehachapi Renewable Transmission Project, for example, recovers costs for transmission investment from interconnecting renewable generators through California ISO's transmission access charges. As a backstop, California Public Utilities Commission-approved rates recover the costs of any unsubscribed portion of the transmission project. Another example is in Texas. Pursuant to Texas law, costs associated with Texas' several "Competitive Renewable Energy Zones" projects are paid by all transmission customers in Texas (the Electric Reliability Council of Texas' ("ERCOT") service area). The Public Utility Commission of Texas approves transmission rates for utilities within ERCOT.

In those examples, a single state's Public Utilities Commission approved cost recovery for the entire project. Cost recovery was accomplished through either (1) socialized cost allocation for all transmission customers in the state, or (2) through long-term contracts for generation that included transmission costs, with retail ratepayers backstopping any unsubscribed portion of the project. Both approaches would face very different issues in New England where each of the six states have different requirements of state laws, and the multi-state region presents cost allocation issues. For this mechanism to be successful in New England, some subset of states would need to coordinate on cost allocation and, potentially, siting.

### *E. Strategic Transmission Investments Implementation Questions*

Some questions that policymakers should consider regarding the implementation of a Strategic Transmission Investments mechanism include:

- **What is the process for identifying suitable locations for transmission investments?**
  - **What are the renewable and clean energy resource types the state(s) seeks to develop?**
    *Consideration: Certain resource types have greater development potential in different locations. For example, off-shore wind potential, mid-range water depths, and federal leasing opportunities are available in the Atlantic Ocean off southern New England. Significant on-shore wind resource potential exists on mountain ridges in northern New England. Each of these resource types has different operating characteristics, cost estimates, and distances to electricity customers and the existing transmission grid.*
  - **Are those resources located within the same state as the electricity customers that would pay for the Strategic Transmission Investments?**
    *Consideration: Location within the same state may simplify cost allocation and siting issues. Location across state borders may require additional coordination.*
  - **Is collaboration among states necessary to equitably allocate costs or facilitate transmission siting processes?**
    *Consideration: Collaboration may increase time, complexity, and cost, but may help achieve the preferred resource mix and associated characteristics and decrease litigation risk.*
  - **Are there technical considerations associated with particular locations? For example, is a particular type of transmission technology indicated by the origination or destination locations on the transmission system?**
    *Consideration: Long distances and/or origination in the Quebec system may indicate advantages of high-voltage direct current ("HVDC") transmission, which can be expensive relative to AC transmission. Shorter distances and/or origination in other adjacent control areas may be better suited to AC transmission solutions. In some circumstances, it may be easier or lower cost to integrate AC transmission to the New England system. Alternatively, HVDC that bypasses AC system bottlenecks may result in less congestion. Adding resources to the middle of an HVDC line will require an additional converter station, which is expensive.*
- **What is the amount of power that the state requires for its policy objectives?**
  - **Are there scales of production that result in various levels of transmission investment?**
    *Consideration: Sizing transmission to be fully utilized can bring down the per-unit cost. AC transmission can be scaled to various levels of transmission. HVDC transmission can also be scaled, but due to the cost of converter stations is often most economic at larger scales (e.g., 1,000 – 1,200 MW).*

- **Are there other strategic objectives (i.e., reliability, economics, fuel diversity, etc.) states wish to incorporate into the transmission investment?**
  *Consideration: Additional interconnections with neighboring systems or reinforcing critical circuits can improve reliability of the system. Transmission that enables resource diversity also provides reliability benefits. Transmission that alleviates bottlenecks may have operational and economic benefits.*

# VII. Forward Clean Energy Market

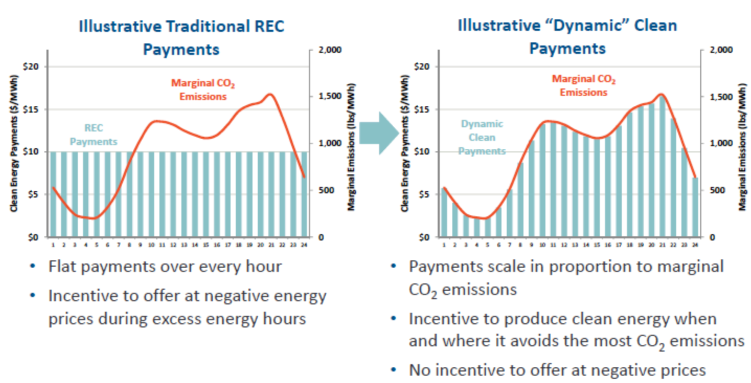
## *A. <u>FCEM Mechanics</u>*

The FCEM is a new idea. It is a potential market-based mechanism intended to be a tool to help the New England states achieve their respective clean energy requirements. The FCEM concept was proposed by a group of stakeholders in the 2017 IMAPP process. It remains subject to discussion and consideration of many basic questions, including threshold issues related to state authority. This paper analyzes one form of an FCEM to assist consideration of its potential viability and implications on consumers.[65]

FCEM has much in common with other market-based mechanisms like RPS and CES. The FCEM products are clean energy attributes of eligible resources. It is fundamentally different, however, in that ISO-NE would administer the FCEM. This is similar to how ISO-NE administers the current capacity market.

The IMAPP version of an FCEM product would have two components: (1) a so-called "anchor price" component of the clean energy attribute, and (2) a "dynamic" component of the clean energy attribute.[66] The clean energy attribute would be sold at an ISO-NE-administered auction three years in advance, similar to the FCM. The forward auction establishes the "anchor price." The dynamic component of the clean energy attribute would be compensated through an ISO-NE settlement process whenever the eligible resource is generating power on an hour-by-hour basis. Its value would be determined by air emissions characteristics of the system mix at the time of production. The dynamic component of the clean energy attribute would have a relatively low value when the system mix's air emissions are low relative to a benchmark emission level. Similarly, the dynamic clean energy attribute would have a higher value when the system mix's air emissions are higher, as shown in Figure 10 below.

**Figure 10: Illustration of IMAPP FCEM Proposal's Dynamic Attribute Valuation**




*Source: Brattle Group*

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[65] The FCEM analyzed in this study is not the same as the FCEM proposed in the IMAPP process. While the two share many similarities (e.g., centrally-administered market for clean energy attributes), the FCEM mechanism in this analysis is simplified to focus on the underlying economics of the clean energy attribute (e.g. no multi-year price-lock, no dynamically-valued component of the clean energy attribute, etc.).

[66] For more information *see*, Brattle Group presentation, *A Dynamic Clean Energy Market: Straw Proposal for a Long-Term IMAPP Design* (May 17, 2017) ("IMAPP FCEM Proposal"), at 4-5, available at http://nepool.com/uploads/IMAPP_20170517_LT_Straw_Dynam_Clean_Energy_Market.pdf.

The anchor price of the clean energy attribute provides a degree of certainty and lead time for developers. The dynamic component of the clean energy attribute establishes a market-based price signal for clean energy resources to produce at times when the system mix's air emissions are highest. Table D below summarizes how the IMAPP FCEM clean energy attribute components work together.

**Table D: IMAPP FCEM Attribute Components**

| Attribute Component | Pricing | Valuation | Benefits |
|---|---|---|---|
| **"anchor price" component** | Established in-advance through centrally-administered auction (like FCM) | Value of this component does not change over the course of the commitment period (e.g., one year) | Provides revenue certainty<br>May also be price-locked for 7-12 years |
| **"dynamic" component** | Determined through the energy market settlement process, depending on power system emission levels relative to an index average value | Value of this component will change on an hour-by-hour basis over the course of the commitment period | Provides market-based price signal to provide clean energy attributes when system emission levels are highest |

Another feature of the FCEM is the so-called "price lock." A price lock would allow a new resource eligible for the FCEM to fix the price at which its base FCEM products are sold for a multi-year period (e.g., seven to 12 years). The price lock is intended to help facilitate financing for new resources.

Importantly, the demand for such clean energy attributes through the FCEM would be determined by state-specific bids. FCEM proponents suggest that each state would establish "demand bids" for clean energy attributes on a regular (e.g., annual) basis. These demand bids would represent the prices at which each state would be willing to procure quantities of clean energy attributes. For example, one state may wish to procure 50MW at $5/MWh, 25MW at $10/MWh, and 5MW at $20/MWh (i.e., as the price level increases, less quantity is demanded). Whether and how state demand bids would work in practice is unknown. At this point in time, the FCEM remains largely conceptual and, to the extent it is pursued further, many elements require additional legal and other analysis.

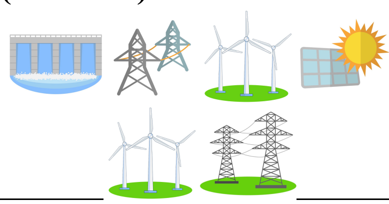
**For this Analysis, the FCEM mechanism was simplified to focus on the economics of the clean energy attribute.** LEI performed computer modeling to examine the potential impacts of an FCEM. LEI's FCEM analysis included a supply outlook for eligible clean energy resources.[67] For LEI's FCEM analysis, all existing and new Class I RPS-eligible resources plus new imported hydropower were eligible. Supply offer prices for existing resources were based on publicly-

[67] In contrast, the Phase I analysis *assumed* certain levels and types of new renewable resources would be developed. The LEI FCEM analysis *forecasts* the resource types and offer prices based on an assumed level of demand.

available, industry estimates of going forward costs and forecasted energy and capacity market revenues. Supply offer prices for hypothetical new resources were based on the National Renewable Energy Laboratory's current estimates of capital costs, recent ISO-NE analysis of potential transmission costs, and forecasted energy and capacity market revenues.

LEI assumed demand for clean energy attributes in the LEI FCEM analysis equal to the Phase I analysis 'More Aggressive RPS 40-45%' scenario's demand for renewable energy. LEI combined all of these elements to project FCEM market participation and forecast the resulting resource mix. LEI then forecasted prices in the FCEM and estimated consumer costs for an assumed level of demand for clean energy (the RPS 40-45% level of demand).

**Table E: Overview of FCEM Scenario and Assumption Details**

| Scenario | 2025 | 2030 |
|---|---|---|
| **Forward Clean Energy Market 40%-45% ("FCEM")**<br> | +7,875 GWh Clean Energy<br>(+1,000 MW HVDC)<br>(90% Capacity Factor)<br><br>+925 MW On-Shore Wind<br>+2,275 MW Solar PV<br>+3,550 MW On-Shore Wind<br>(+3,600 MW HVDC) | +7,875 GWh Clean Energy<br>(+1,000 MW HVDC)<br>(90% Capacity Factor)<br><br>+925 MW On-Shore Wind<br>+4,775 MW Solar PV<br>+4,050 MW On-Shore Wind<br>(+3,600 MW HVDC) |

In general, the FCEM mechanism shares many of the characteristics of a RPS or CES. For example, the price for clean energy attributes would be set by the most expensive resource selected for participation (i.e., the next or "marginal" resource to provide clean energy attributes). One of the most significant differences between an FCEM and a RPS or CES involves jurisdictional issues.[68] That is, ISO-NE would administer it pursuant to a federally-regulated tariff. It would not be under the states' direct control. The jurisdictional issue presents additional risks to states in the execution of their laws, such as litigation before FERC over the FCEM design in which states are a party and not the decision-maker. On the other hand, market participants may perceive an FCEM to present less risk associated with regulatory uncertainty and frequent changes to resource-type eligibility or classes, which can affect the estimated profitability of a particular project and introduce financial risk.

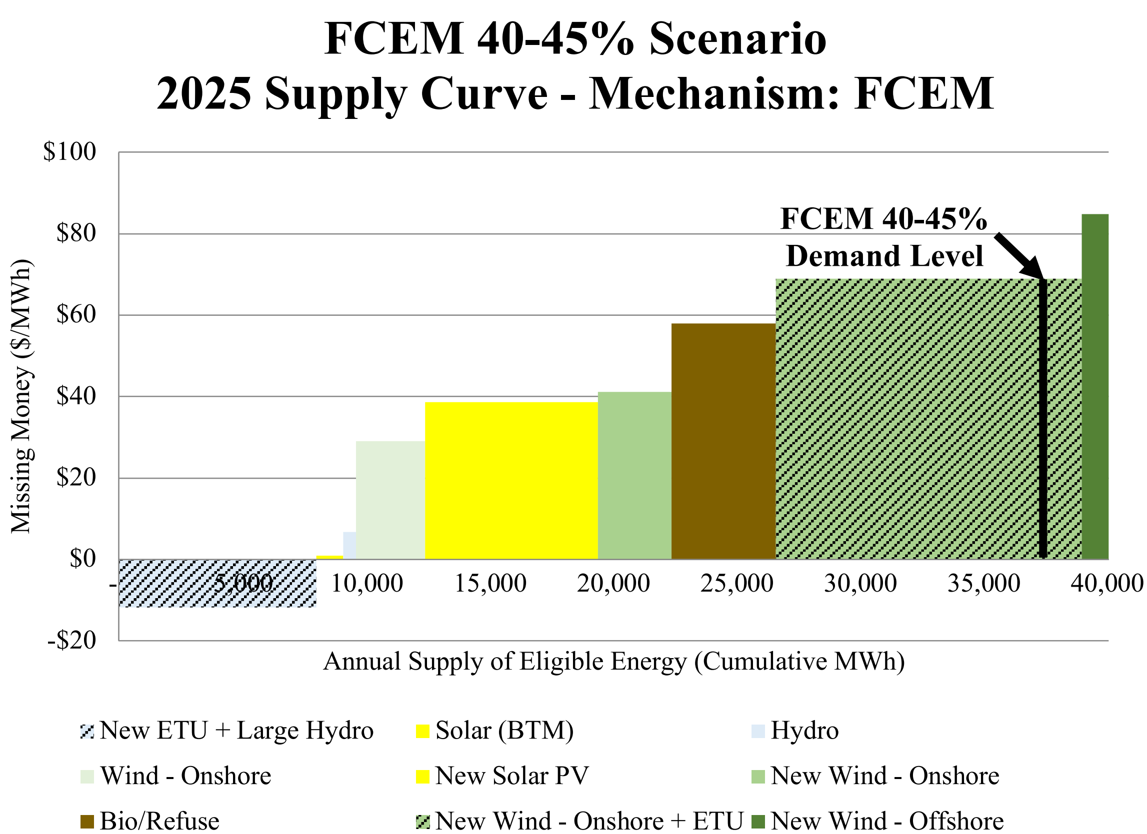
### *B. <u>FCEM Illustration</u>*

The graphic below, Figure 11, presents the aggregated supply of clean energy attributes from existing and new renewable and new clean energy resources in New England for the hypothetical future year 2025. Based on LEI's current outlook for these resources, Figure 11 shows the aggregated supply of clean energy attributes (i.e., the product traded in an FCEM) from lowest price on the left to highest price on the right. The price levels in this illustration are equal to the

68 While there are other significant differences between NEPOOL's FCEM concept and an RPS or CES (e.g., the price-lock), the jurisdictional issue would transfer a degree of control over state energy and environmental policy implementation to ISO-NE and its regulator, the Federal Energy Regulatory Commission.

"missing money" amounts estimated by LEI for eligible resource types in the FCEM 40-45% scenario for 2025.

**Figure 11: Illustration of FCEM Mechanism**




Similar to RPS and CES, the market price for clean energy attributes in the FCEM is determined by supply and demand. In this scenario, which is based on LEI's current outlook for renewable and clean energy, new on-shore wind combined with additional transmission investments are the most expensive resource selected by the FCEM. This resource type's missing money estimate ($69/MWh in 2025) establishes the price paid to all eligible resources. New off-shore wind is not selected by the FCEM because there is ample supply of lower cost eligible resources. However, by 2030 the missing money difference between new on-shore wind with transmission and new off-shore wind diminishes. After 2030, new off-shore wind is projected to cost less than new on-shore wind with transmission. This indicates a potential shift in the supply of clean energy attributes in the FCEM.

### *C.* ***<u>FCEM Design Considerations</u>***

The FCEM is intended to use competitive forces to achieve the states' objectives at the lowest cost over time. The FCEM can incorporate many of the features of the RPS and CES (e.g., eligibility and classes or tiers to target certain types of resources). Preliminary discussion of the FCEM concept in the IMAPP process included new features discussed below.[69]

***FCEM Product Definition and Resource Eligibility***

Like an RPS or CES, an FCEM could be designed to promote certain renewable and clean resource types. This could be accomplished through the rules for FCEM eligibility. Rather than establishing classes or tiers, the FCEM could be designed to have more than one product: a base product and a premium product. A base product would be comprised of all eligible resource types. A premium product could be designed to incent specific resource types with certain characteristics (e.g., higher costs, delivered to certain locations on the transmission system, desirable availability, dispatchable, associated transmission investment and or capacity deliverability, etc.). The base product could be designed to achieve the majority of the aggregated states objectives. The premium product could be designed to target specific state policy objectives.

***Expressing Demand for Clean Energy and Demand Bids***

To procure clean energy through the FCEM, the marketplace needs to know the quantities of clean energy attributes that will achieve state policy objectives. For the FCEM, states would need to identify these quantities years in advance. To protect consumers, states would also need to identify the prices at which they are willing to procure clean energy attributes. To facilitate financing of new resources, FCEM proponents believe that states need to maintain consistent quantities over time.[70]

Each individual state could express its preferences on these issues through a demand bid that includes price and quantity. The states' collective interest in procuring clean energy attributes, at certain prices and quantities, would then be aggregated and represented in the FCEM by a demand curve. The intersection of available supply and the aggregated states' demand (or demand curve) would determine the price paid to all eligible resources.

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69 ISO-NE also provided a discussion paper that highlighted four practical issue and concerns related to an FCEM: (1) Contract Type and Structure, (2) Governance of FCEM Qualification and Demand, (3) Offer Price Mitigation, and (4) Auction Design. ISO New England Discussion Paper, *NEPOOL 2016 IMAPP Proposals: Observations, Issues, and Next Steps* (January 2017) ("ISO-NE Discussion Paper"), at 4-15, available at http://nepool.com/uploads/IMAPP_20170125_ISO-NE_Discussion_Paper_Rev.pdf.

70 IMAPP FCEM Proposal at 13-14.

Accordingly, the FCEM could be designed to express demand for clean energy attributes by establishing the minimum and maximum values as follows:

- ***Quantity*** – expressed in MWh or similar equivalent[71]
- ***Price*** – expressed in $/MWh or $/clean energy attribute
- ***Time*** – expressed in the amount of time (e.g., number of years) the bid would cover

Table F below presents several considerations associated with states designing demand bids to achieve clean energy requirements. In theory, states could balance these considerations in their demand bids. The FCEM would need to have rules around these parameters established in advance.

**Table F: FCEM Demand Bid Design Considerations**

| | **"Greater" Bids** | **"Smaller" Bids** |
|---|---|---|
| **Quantity / Size** | Larger sized bids may attract larger scales of production and/or better financing terms due to economies of scale | Smaller-sized bids may enable resources with lower / smaller scales of production to participate |
| **Price** | Higher price levels may attract additional supplies of eligible resources but expose consumers to higher costs | Lower price levels may protect consumers but limit eligible supply and/or resource types |
| **Time / Duration** | Longer duration bids would likely help facilitate financing | Many renewable and clean energy resources are projected to be available at lower prices in the future, and shorter duration bids may enable better responsiveness to these pricing trends |

***Revenue Stability***

To address concerns related to facilitating financing for new resources, the FCEM could be designed to ensure that new resources receive an initial price level for a period of several years. This price-lock feature has been used to attract new resources in the capacity market. The amount of time for which a resource is entitled to its initial FCEM price could be tailored to the unique requirements of new renewable and clean energy resources. Some market participants claim that more than seven years of stable revenues are required to facilitate financing for new

71 Renewable energy attributes, or RECs, have commonly been measured on a basis equivalent to the energy production from which the attributes were created. For example, one MWh usually entitles the relevant resource owner to one REC (i.e., 1-to-1). Some states have provided additional incentives for specific resource types by adjusting this ratio. For example, offshore wind, or resources located in a specific location, could be given more than one clean energy attribute for each MWh of production (e.g., > 1-to-1).

resources. Alternatively, existing resources may not require the same degree of revenue stability to maintain economic viability.

Whether or not an FCEM locks prices for new and/or existing resources would affect costs consumers pay for clean energy attributes. A multi-year price lock for new resources may help facilitate better financing terms and lead to lower costs for newer resources. However, in light of projected declining prices for new resources, a multi-year price lock could prevent consumers from benefiting from lower costs in the future.

***Locational Issues***

At a threshold level, resources must be capable of delivering power into the New England system to be eligible for revenues from renewable and clean energy attributes. Otherwise, the prices associated with an individual resource should reflect transmission system limitations. Whether the FCEM is designed without regard to transmission system limits (i.e., anywhere in the New England system suffices), or uses delivery zones to establish premium or discount prices, will affect what resources the market selects. Using multiple delivery zones could incorporate necessary transmission investments into resource pricing. Multiple delivery zones also increase complexity of administering and participating in the FCEM.[72]

### *D. FCEM Benefits and Challenges*

***Central Administration***

FCEM has similarities with an RPS and CES, such as market-based pricing. However, compared with a state-administered program, the FCEM would be administered by a third-party, such as ISO-NE.[73] A centrally-administered FCEM could present some efficiency for eligible resources. For example, a resource that only needs to qualify once, rather than in each state, could have lower transaction costs that it could, in theory, pass on to consumers. The centrally-administered market-based price signal may also be more transparent than the state-administered bilateral REC markets. Currently, open offer prices and recent transaction prices in the bilateral REC market can be discovered through subscription-based services or through comprehensive direct communications with market participants. In contrast, a centrally-administered market for clean energy attributes is envisioned to have such information published on a free, web-based portal in a timely manner, similar to ISO-NE's energy and capacity markets. Such additional transparency may help facilitate financing and new resource development.

***Resource Diversity vs Consumer Costs***

Similar to other market-based mechanisms, the FCEM uses price (and only price) to select which resources will be paid for clean energy attributes. Depending on how the FCEM product(s) and the associated eligibility criteria are defined, this approach is designed to achieve state policy objectives at least cost. It may, however, also result in a clean energy portfolio that has little diversity. Moreover, existing resources are likely to have a competitive advantage over new resources. These outcomes may not be consistent with some states' objectives to support newer technologies and industries or target specific resource types. The price of a resource may not

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[72] *See* IMAPP FCEM Proposal at 6. *See*, also, a discussion of issues related to technical feasibility of co-optimization with the FCM in the ISO-NE Discussion Paper at 14.

[73] It is possible that other third-party administration models may be potential options.

capture all of its beneficial attributes, and the FCEM's focus on cost may therefore limit some states' ability to satisfy unique energy and environmental objectives.

***Wholesale Electricity Market Compatibility***

The FCEM would be generally compatible with the wholesale electricity markets. FCEM base product revenues would be judged competitive and thus considered in the capacity market offers of eligible resources (similar to RPS, but unlike Long-Term Contracts).[74] This would allow clean energy resources to offer capacity at lower prices and increase the likelihood that ISO-NE would count its capacity toward regional resource adequacy targets.

A question remains whether a premium FCEM product would receive such treatment. To the extent that FCEM premium product revenues are not considered competitive, consumers may overpay for the region's capacity.

***Incentive to Produce When Emissions and Energy Prices are High***

Another potential benefit of the proposed FCEM is the dynamically-priced component of the clean energy attribute. Separate from the anchor prices established for FCEM products three-years in advance, payment for delivery of clean energy attributes in real-time would include additional value associated with system emissions at the moment of delivery.[75] For example, a clean energy resource that produces electricity during the summer or winter peak (which coincides with the highest power sector air emissions) would receive a higher amount of revenues for its clean energy attributes. Alternatively, a resource that produces during periods of relatively low demand (and low air emissions) would receive less money for the dynamic component of its clean energy attributes.

This feature provides resources with an economic incentive to provide clean energy when it is capable of displacing a greater amount of power sector air emissions. To the extent that this affects the offers in the FCEM, it may help states achieve state policy objectives more cost-effectively.

Lastly, power sector air emissions and energy market prices have a strong relationship in New England. Incentives to produce energy during periods of high emissions may also result in lower energy prices and provide system operational benefits.

***ISO-NE Administration Means Federal Control***

ISO-NE is federally regulated by the FERC. Rules to implement an FCEM would be incorporated into ISO-NE's tariff. These rules would be filed with the FERC for review and approval and, as with all other tariff rules, would be subject to the FERC's ongoing oversight. FERC could, accordingly, exercise its discretion regarding the details associated with establishing and implementing the FCEM. There are many open legal questions regarding the FCEM, including whether the FERC has the legal authority to regulate the costs to electricity customers for clean energy attributes.

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74 Here, the description "Base Product" refers to a potential segmentation of the FCEM market, similar to "classes" or "tiers" in the RPS/CES context.

75 As a reminder, LEI's FCEM Scenario modeling did not include the additional value associated with the dynamic component of the clean energy attribute. LEI's analysis focused on the missing money estimates for various resource types over the course of the year.

States that wish to use the FCEM to achieve their policy objectives could become parties to any FERC proceeding, but they would not make decisions on the rules governing the FCEM, which would be subject to federal law. Federal jurisdiction over the FCEM would, therefore, create a litigation risk for states that is not present in connection with state-jurisdictional mechanisms.

***Uncertainty as to State Preferences***

State laws reflect a state's consideration of a variety of factors. It is not possible to predict with any certainty what the full suite of factors important to a state may be at any point in time or how much weight a state will assign to one over another in assessing the appropriate path for that state's consumers.

***Demand Bids are Novel***

As discussed, states would express their demand for clean energy attributes through demand bids. This is a new concept. The legal authority, process, and technical issues related to states establishing demand bids would need to be resolved to make the FCEM a viable option for achieving state policy objectives.

***Transition Issues***

The creation of the FCEM would impact existing mechanisms and the resources that rely on revenues from those mechanisms for financial viability. Depending on many open issues, there may be significant overlap between the FCEM and other mechanisms. Such impacts would need to be better understood and addressed to minimize economic disruption for these resources.

### *E. FCEM Implementation Questions*

Some questions to consider regarding the implementation of the FCEM mechanism include:

- **Are States inclined toward a path that could ultimately cede implementation of states' renewable energy laws and regulations to decisions by ISO-NE and/or FERC?**

  *Consideration: A federally administered FCEM would reduce or at the very least influence the level of state control over implementation of state renewable laws and regulations. This could ultimately create the potential for ISO-NE and/or FERC to exercise their judgment or make decisions about the execution of state laws. If this potential outcome is not agreeable to all of the New England states, how and to what extent might that affect implementation?*

- **How responsive would ISO-NE and the FERC be to state determinations?**
  - **Does the FERC have the legal authority to regulate costs for clean energy attributes?**
    *Consideration: The Federal Power Act does not explicitly grant the FERC authority over clean energy attributes. This threshold legal question may affect the viability of the mechanism and create significant litigation risks.*
  - **Would ISO-NE and FERC defer to states on critical FCEM design details?**
    *Consideration: ISO-NE administers the wholesale markets without preference for resource types. To the extent that implementation of the FCEM affects economic incentives for market participants, ISO-NE, and FERC may need to balance*

*interests between economic efficiency and state requirements or objectives. When adjustments to the FCEM are necessary, or advocated for by market participants, ISO-NE or FERC may express a preference for a different set of priorities than the states in connection with the execution of state objectives.*

- **How would states mitigate litigation risks associated with federal jurisdiction?**
  *Consideration: The Federal Power Act establishes a right for anyone to file a complaint regarding market rules. The FERC is not bound to resolve disputes in favor of the states. Any outcome from, or change to, the FCEM would be subject to FERC review. The states can participate in such proceedings, but do not have a decision-making role in the rules governing how ISO-NE would implement state objectives through an FCEM.*

- **What legal authority, state regulatory processes, and technical expertise would states need to develop demand bids for clean energy attributes?**
  *Consideration: State control over FCEM participation would be accomplished through the submittal of demand bids. States may need new legal authority to develop and submit binding demand bids (which could be on an annual basis). It is unclear what regulatory process states would use to develop demand bids.*

- **In addition to current mechanisms and legally mandated procurements, how much clean energy would states procure through an FCEM?**
  *Consideration: Developing and implementing a new forward market for clean energy attributes is not trivial or inexpensive. Ratepayers ultimately shoulder these administrative costs. To justify such effort and expense, states would need to intend to use an FCEM mechanism to satisfy a significant portion of their future clean energy attribute requirements.*

- **What impact would an FCEM have on existing mechanisms and resources?**
  *Consideration: An FCEM could affect the incentives provided by other mechanisms. To effectively implement state objectives, the interactions between an FCEM and other existing mechanisms would need to be better understood to minimize economic disruption to the clean energy industry.*

- **What are impediments to FERC approval of an FCEM?**

  *Consideration: The filing of an FCEM proposal would be a matter of first impression for FERC. Based on other FERC proceedings concerning New England wholesale markets, some parties will inevitably raise challenges regarding, among other things, the relationship between the FCEM and competitive pricing in other ISO-NE markets. While FERC has expressed support for mechanisms that seek to harmonize wholesale markets and state laws, it is unknown how FERC would react to an FCEM.*

# VIII. Comparative Analysis

This section uses qualitative and quantitative information to compare and contrast the various mechanisms states could consider using to achieve the requirements of state laws. It includes a chart identifying the benefits and challenges associated with each mechanism discussed above.

Consumer costs are presented in two ways: (1) energy, capacity, and average mechanism costs for each scenario, and (2) mechanism costs relative to one another, based on representative design approaches for each mechanism. Next, this section presents variations in mechanism design and associated mechanism costs for each scenario. Finally, this section concludes with power sector carbon dioxide emissions trends and mechanism costs per ton of emissions reductions for each scenario.

*Importantly, the modeling results and cost estimates are directionally indicative. These results and estimates are not a substitute for actual information that would emerge through competitive processes or actual future market outcomes.*

## *A. Mechanism Benefits and Challenges Comparison*

Table G below presents a summary of some of the benefits and challenges of mechanisms that could be used to support the requirements of state laws.

**Table G: Illustrative List of Mechanism Benefits and Challenges**

| Mechanism | Benefits | Challenges |
|---|---|---|
| Renewable Portfolio Standard | • Promotes development of some types of renewable resources<br>• Balances investment risk between investors and consumers<br>• Considered to be compatible with the competitive wholesale market<br>• Sends transparent REC market price signal<br>• Enables policymakers to balance resource type diversity with consumer costs | • Developers indicate challenge in facilitating financing of new resources and/or transmission<br>• Increases investor investment risk due to regulatory changes and short-term price volatility<br>• Creates potential for market power among certain eligible resources depending on how a state structures classes or tiers |

**Phase II: Mechanisms Analysis - 2.0**

| Mechanism | Benefits | Challenges |
|---|---|---|
| Clean Energy Standard | • Balances investment risk between investors and consumers<br>• Enables market-based compensation for clean energy attributes<br>• Considered compatible with the competitive wholesale market<br>• Sends transparent market price signal<br>• Enables policymakers to balance resource type diversity with consumer costs | • Limited practical experience exists to enable assessment of effectiveness<br>• *Like RPS:*<br>  • Creates potential for market power among certain eligible resources<br>  • May not facilitate financing of new resources and/or transmission<br>  • Could increase investor investment risk due to regulatory changes and short-term price volatility |
| Long-Term Contracts | • Has facilitated financing of new resources<br>• May lower financing and development costs due to revenue certainty for investors<br>• States have experience with this mechanism | • Shifts risks to consumers over the life of the contract<br>• Prevents adjustments based on technology cost declines or technology advancements over the term of the contract<br>• Diminishes competitive incentive to reduce costs over long-term<br>• Not considered as compatible with the current competitive wholesale market as other mechanisms<br>• Potential indirect effect on wholesale market incentives |
| Strategic Transmission Investment | • Enables interconnection and delivery of power from specific types of resources | • No experience in New England<br>• Depending on size and cost, could require one or more |

| Mechanism | Benefits | Challenges |
|---|---|---|
| | • Reduces investment risk for resource developers<br>• Allows multiple strategic considerations in addition to public policy resource development | states to coordinate and agree on resources and costs<br>• Ability to influence resource mix is location dependent<br>• Open access transmission rules may enable free riders and/or any resource (fossil fuel-fired) to use infrastructure<br>• Due to jurisdictional issues, states may have less control over how state policies are implemented and in disciplining costs |
| Forward Clean Energy Market | • Many of same benefits as RPS and CES<br>• May present lower barriers to resource participation due to centralized administration and consistent rules regarding eligibility<br>• May provide participating resources some efficiencies associated with one buyer for all of its products (i.e., energy, capacity, and clean energy attributes)<br>• Market-based price signal may provide additional clarity for investors | • Many of same challenges as RPS and CES<br>• Due to jurisdictional issues, states may have less control over how and at what cost state policies are implemented. Demand bid concept has not been applied to clean energy attribute markets before<br>• No experience in New England<br>• Risk of litigation over the implementation of the requirements of state laws before FERC where states could be parties but not decision-makers<br>• Risk of ISO-NE or market participants changing the model over time, in ways that depart from any agreement among states, ISO-NE and market participants at its outset |

**Table H: New England State Experience with the Mechanism**

| **Mechanism** | **Experience** |
|---|---|
| Renewable Portfolio Standard | New England States have practical experience with RPS. Some have had an RPS since the late 1990s. |
| Clean Energy Standard | New England States have little experience with CES. One state in New England enacted a CES in 2017. |
| Long-Term Contracts | New England States have practical experience with long-term contracts through PURPA. Some states have more recently authorized their utilities to enter into long-term contracts to facilitate financing of certain new resources. |
| Strategic Transmission Investment | New England States have no experience with Strategic Transmission Investments. Some single-state examples exist in other states around the country. |
| Forward Clean Energy Market | New England States have no experience with FCEM. There is no experience elsewhere from which to draw. Some concepts could be adapted from RPS or CES. Some demand bid examples from other industries around the world could provide some guidance. |

**Table I: ISO-NE and Market Participants Experience with the Mechanism**

| **Mechanism** | **Experience** |
|---|---|
| Renewable Portfolio Standard | ISO-NE and Market Participants have practical experience with RPS. The ISO-NE Market Monitor reviews RPS revenue projections in the FCM context. |
| Clean Energy Standard | ISO-NE and Market Participants have little experience with CES. Market participants that operate in Massachusetts, Illinois, and/or New York are beginning to develop experience with this mechanism. |
| Long-Term Contracts | Some Market Participants have practical experience with long-term contracts through PURPA or through recently authorized long-term contracts with utilities that may facilitate financing of certain new resources. |

| **Mechanism** | **Experience** |
|---|---|
| Strategic Transmission Investment | ISO-NE and Market Participants have no experience with Strategic Transmission Investments. Some single-state examples exist in other states around the country. |
| Forward Clean Energy Market | ISO-NE and Market Participants have no experience with FCEM. There is no experience elsewhere from which to draw. Some concepts could be adapted from RPS or CES. Some demand bid examples from other industries around the world could provide some guidance. |

**Table J: Mechanism Risk Considerations[76]**

| **Mechanism** | **Risk Considerations** |
|---|---|
| Renewable Portfolio Standard | RPS generally maintains investment risk with investors. May not be sufficient to facilitate financing of new resources and / or investments in associated transmission. |
| Clean Energy Standard | CES generally maintains investment risk with investors. May not be sufficient to facilitate financing of new resources and / or investments in associated transmission. |
| Long-Term Contracts | Long-Term Contracts shift investment risks away from investors toward electricity consumers. Market participants have cited tension between these contracts and the wholesale competitive market design. Whether Long-Term Contracts save or cost consumers money over time depends in large part on assumptions regarding future prices, other analysis, and contract provisions. |
| Strategic Transmission Investment | In an ETU, the risk would lie with utility ratepayers. If the generator is not built, subject to any contractual remedies, consumers would still pay and not receive any power. Costs and risks of PPTUs are borne by all ratepayers in New England but are mitigated to some extent. |
| Forward Clean Energy Market | FCEM generally maintains investment risk with investors. May or may not be sufficient to facilitate financing of new resources and / or investments in associated transmission. |

[76] While the risk considerations discussed here focus primarily on cost, it is important to recognize that any mechanism intended to promote the development of clean energy resources is being employed to achieve a multitude of policy objectives.

| Mechanism | Risk Considerations |
| --- | --- |
| | ISO-NE administration over a market for clean energy attributes may raise jurisdictional issues and risks of litigation. Given ISO-NE's independent status and focus on wholesale electricity market prices, states may have less control over how and at what cost state laws are implemented. Even if there is agreement among states, ISO-NE, and market participants at the outset, there is history in New England of a few market participants litigating market rule changes that had been broadly supported. However, some level of state control is maintained due to the use of state supplied demand bids. |

### *B. Mechanisms' Costs: Comparisons and Their Challenges*

Key differences among mechanisms make definitive comparisons of their consumer cost implications challenging. Some of the fundamental differences that require caution in drawing conclusions about cost comparisons include:

1) differences in how many and what type of resources the mechanisms are designed to support – a diversity of eligible resources at one price (RPS, CES, FCEM) v. one or a finite number of specific resources (Long-Term Contracts);

2) differences in how mechanisms deal with *all* the costs a resource requires to become operational (Strategic Transmission Investments); and

3) differences in how mechanisms allocate risks – and the costs associated with those risks – between resource owners and consumers such as the risk of getting assumptions wrong, or the missed opportunity of technology cost declines (RPS v. Long-Term Contracts, for example).

Whether one favors a particular mechanism over another is subjective, dependent on many competing variables, assumptions, and risk tolerances. Judgment about consumer cost implications requires a fact- and objective-specific assessment. This includes, for example, answers to the following questions:

- What quantity of resources are required?
- How frequently will new resources be required?
- Is diversity of resources important, such as resource size, type, operational characteristics, and/or location?
- Is large-scale transmission required or desired?
- In light of required volumes, does the mechanism maintain a competitive wholesale market that sends proper price signals to *all* resources to serve consumers at the lowest cost over the long-term?

- What is the preferred placement of risk by and between resource developers and consumers?
- How are jurisdictional issues weighed?

Moreover, two of the mechanisms - Long-Term Contracts and Strategic Transmission Investments - are so fundamentally different from the other three - RPS, CES and FCEM – that one must be careful not to conclude that *apparent* cost advantages will result in *actual* cost advantages.

For these reasons, this section cannot and does not offer a conclusion about whether one mechanism is better suited to satisfy a state's needs over time than another mechanism. That judgment requires an assessment of state-specific facts, objectives and risk tolerances, and other considerations including those identified above. With those critical caveats, this section observes some relative economics and consumer cost implications of various mechanisms.

This section presents consumer costs in several ways:

(1) on a consistent basis with the same objective,

(2) as a function of "missing money" for renewable and clean energy resource types,

(3) energy, capacity, and mechanism costs for each scenario, and

(4) mechanism costs relative to one another, based on representative design approaches for each mechanism.

This section also presents cost information to show the directional implications of variations in some of the mechanism design options available to states.

### 1. Consumer Costs

Comparing consumer cost estimates for the different mechanisms must be done with the caution one would use in comparing, for example, apples, oranges, and bananas.

**On Interpreting Mechanism Cost Comparison:**

Importantly, the cost estimates presented in this analysis are designed to be illustrative, not predictive.

- Phase I modeling results are based on assumptions, many of which will turn out to be inaccurate with the passage of time. In addition, the renewable and clean energy resource additions in Phase I were assumed, hypothetical future scenarios and may not necessarily represent actual future outcomes.
- Mechanism costs also do not include costs associated with other public policy programs that support energy efficiency or distributed energy resources (i.e., net-metering).
- Mechanism costs are based on "missing money" results from Phase I and include several simplifying assumptions related to actual mechanisms currently in place in the New England states.
- Lastly, cost estimates are influenced by the timing of the business cycle. Specifically, when the costs of new resources exceed the average cost of existing resources, market-based mechanisms like RPS appear more expensive than during the part of the business cycle when the opposite is true.

Even if the five mechanisms had identical objectives and parameters - resource eligibility and target quantity, for example - they would not have the same consumer costs.[77]

Three of the mechanisms - the RPS, CES, and FCEM - would have similar costs if they had the same resource eligibility and quantity targets. That is because these mechanisms pay all eligible resources the same price – the price of the most expensive eligible resource.

The Strategic Transmission Investment mechanism appears to cost less than the RPS, CES and FCEM. That is because the Strategic Transmission Investment mechanism places the cost of transmission in a bucket separate from the clean energy resource. Consumers hold that bucket too, but the costs in it are separated from the clean energy resource's bucket. If the resource type needing transmission establishes the price paid to all eligible resources, putting transmission costs in another bucket may reduce the cost of the renewable and clean energy resources through RPS, CES, or FCEM (even after adding back in the transmission costs in another bucket). Alternatively, if all the costs were in the same bucket, the clean energy resources could appear to have *same* costs as the resources supported by an RPS, CES or FCM.

The Long-Term Contracts mechanism also *appears* to be less expensive than the other mechanisms. That is because the Long-Term Contract mechanism pays each resource exactly *the amount of the specific resource's* missing money where, as noted, the RPS, CES and FCEM pays

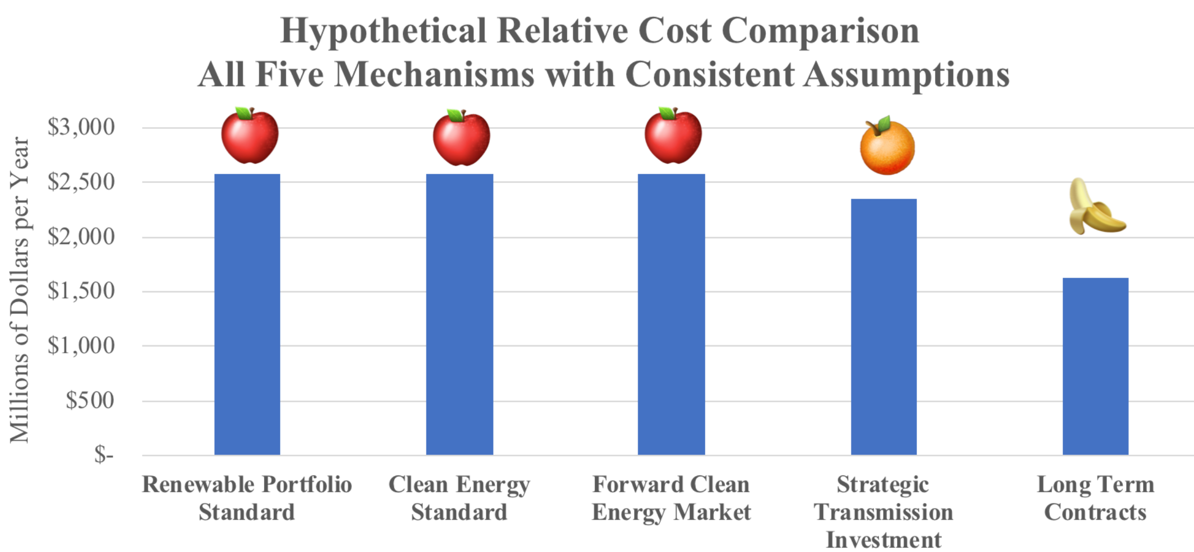
77 **The cost associated with additional transmission to enable delivery of new on-shore wind energy is included in this comparative analysis for all five mechanisms.** The difference in cost estimates for each mechanism is literally a function of whether: (1) the single clearing price paid to all resources includes the cost of transmission for new on-shore wind (RPS, CES, and FCEM), (2) the single clearing price paid to all resources does not include the cost of transmission (RPS, CES, and FCEM), but is paid by consumers through alternative means (Strategic Transmission Investments), or (3) whether each resource type is paid exactly the amount of the specific resource's missing money (Long-Term Contracts).

*all* eligible resources the same amount equal to the price of the most expensive eligible resource. What the Long-Term Contract mechanism's costs do not show are the unknown costs of getting one or more assumptions wrong, the costs consumers would *not* pay if that (or other) resource's costs drop over the contract term, or the missed opportunity for diversity in other clean energy resources' type, size, operating characteristics, costs and/or location.

Against those important backdrops, the cost differences in this analysis depend on whether resources are paid the market price, each resource's offer price, or a combination of the two.[78]

Figure 12 below presents an illustrative comparison of mechanism costs for RPS, CES, FCEM, Strategic Transmission Investments, and Long-Term Contracts. For this comparison, each mechanism is assumed to have the same resource eligibility, target quantity, and underlying "missing money" estimates from the same hypothetical future scenario.[79]

**Figure 12: Comparing Mechanism Costs: Apples, Oranges, and Bananas**




If one changes resource eligibility and design elements - tiers, classes, and carve-outs, the ACP - then cost differences will appear. This is discussed in greater detail below. **Generally, the cost differences from mechanism to mechanism are smaller than the cost differences that result from changing objectives, such as renewable and clean energy quantities, as shown below**. These are presented across the hypothetical future scenarios, below. Importantly, **the difference**

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78 This result highlights what is known in economic terms as the "uniform price" versus "as bid" debate. Whether one approach costs more over time is discussed at length in the economic literature. For example, *see* Tierney, S. et al., *Pay-as-Bid vs. Uniform Pricing: Discriminatory auctions promote strategic bidding and market manipulation* (March 2008), available at https://www.fortnightly.com/fortnightly/2008/03/pay-bid-vs-uniform-pricing.

79 For this illustration, resource eligibility and target quantities are based on the FCEM 40-45% Scenario results for 2025 for all mechanisms. This scenario includes an expanded target quantity, transmission to deliver additional on-shore wind resources and imported hydropower, and LEI's current outlook for renewable and clean energy resource economics. The RPS, CES, and FCEM market price also does not exceed the assumed $80/MWh ACP The Strategic Transmission Investments mechanism pays resources the market price and includes the annual carrying costs for transmission to deliver new on-shore wind.

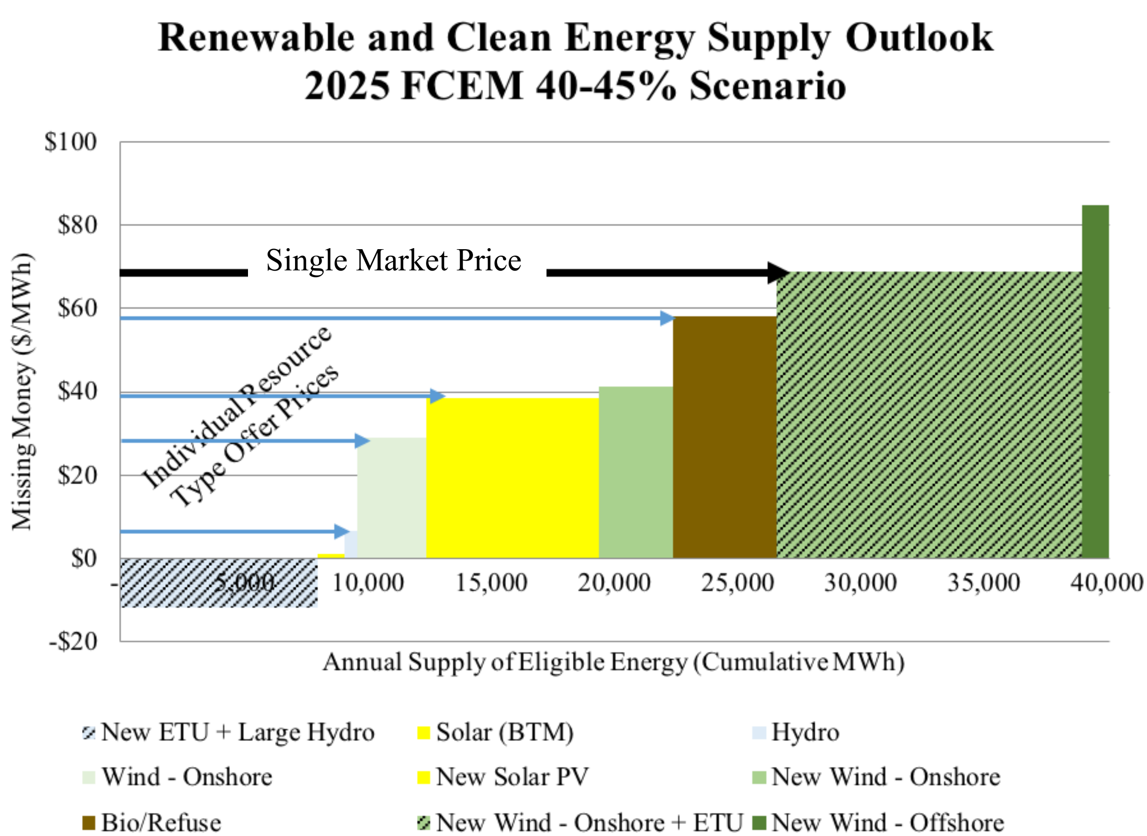
**in costs associated with mechanism design is much less than the aggregate "missing money" increases that result from material declines in energy and capacity revenue when increasing numbers of resources are funded through revenues earned outside of these wholesale markets (and thus consumer costs)[80].**

### a. Single Market Prices and Missing Money

In this analysis, the supply economics for renewable and clean energy resources determine consumer costs for each mechanism. That is, the costs and energy and capacity revenues for each resource type establish the missing money amounts to be recovered through each mechanism.

As noted, the RPS, CES, and FCEM all pay the price associated with the most expensive eligible resource. The missing money estimates therefore set the single market price at the target quantity. For example, if the price is based on new onshore wind with transmission, then *all* resources eligible for the mechanism are paid the same cost per clean energy attribute, approximately \$69/MWh in Figure 13 below. If it was based on new solar, then the cost would be lower at approximately \$39/MWh in Figure 13 below.

**Figure 13: Missing Money, Market Prices, and Customer Costs**

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80 In other words, as more and more "lower cost" renewable/clean energy is added to the system, energy and capacity market prices decline, making these resources more dependent on mechanism revenues due to an increase in the "missing money" requirement.

On the other hand, the Long Term Contracts mechanism would pay each resource its own offer price based on that individual resource type's missing money estimate.[81] In this analysis, Long Term Contracts may *appear* to cost less than other mechanisms because (1) each resource is paid only up to the level of its individual offer price (its actual "missing money") and (2) eligible resources recover costs for clean energy attributes through only one mechanism.[82] While Long Term Contracts might therefore appear to cost less than using a single market price mechanism, as noted in the beginning of this section, many complexities preclude a definitive conclusion.[83] For example, traditional economic literature discusses bidding incentives, anti-competitive behavior, and a lack of adequate information.[84] In addition, the mechanism cost estimates are influenced by the timing of the business cycle. Specifically, when the costs of new resources exceed the average cost of existing resources, mechanisms like RPS appear more expensive than during that part of the business cycle when the opposite is true. Further, as noted above, Long Term Contracts require assumptions, which history may prove wrong, and for example, can preclude consumer cost savings if the contracted technology's (or other clean energy resources') costs decline during the contract term.

Strategic Transmission Investments also may *appear* to cost less than single market price mechanisms such as an RPS, CES and FCEM. In this analysis, Strategic Transmission Investments place the cost of transmission in a separate bucket from the clean energy resource. This *appears* to lower clean energy resources' "missing money" need, but the costs of transmission still exist, and consumers still pay these costs. Resource costs to achieve renewable and clean energy requirements would be recovered through the single market price for clean energy attributes (similar to RPS, CES, and FCEM). Consumers pay costs associated with both of these "buckets." To the extent that recovering transmission costs in this manner results in *lower single market prices* for renewable and clean energy attributes, Strategic Transmission Investments may, however, reduce consumer costs.

***A significant factor influencing the source of consumer costs is the target quantities in the hypothetical future scenarios.*** As discussed below, when the level of renewable and clean

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[81] For example, solar would be paid approximately $39/MWh while new wind onshore + ETU would be approximately $69/MWh noted in Figure 13 above.

[82] Recall that in this analysis, long-term contracts include energy, capacity, and attributes, thereby leading to a total contract price that is higher than just the "missing money." However, energy and capacity products are assumed to be valued at market price, allowing the analysis to focus on "missing money" estimates as the basis for mechanism costs. Costs associated with the Long-Term Contract mechanism in this analysis are based on such "missing money" estimates.

[83] On March 9, 2018, FERC approved ISO-NE's Competitive Auctions and Sponsored Policy Resources (CASPR) proposal. This new market mechanism is designed to protect price formation in the primary FCM auction while simultaneously increasing the likelihood that certain resources with long-term contract revenues are able to be selected by the FCM and are counted toward the region's installed capacity requirement. As a reminder, this analysis does not include the impact of the Minimum Offer Price Rule (MOPR), which CASPR addresses, and is therefore not affected by FERC's approval of CASPR. *See* Phase I at page 2, especially fn. 6, for more information on the MOPR.

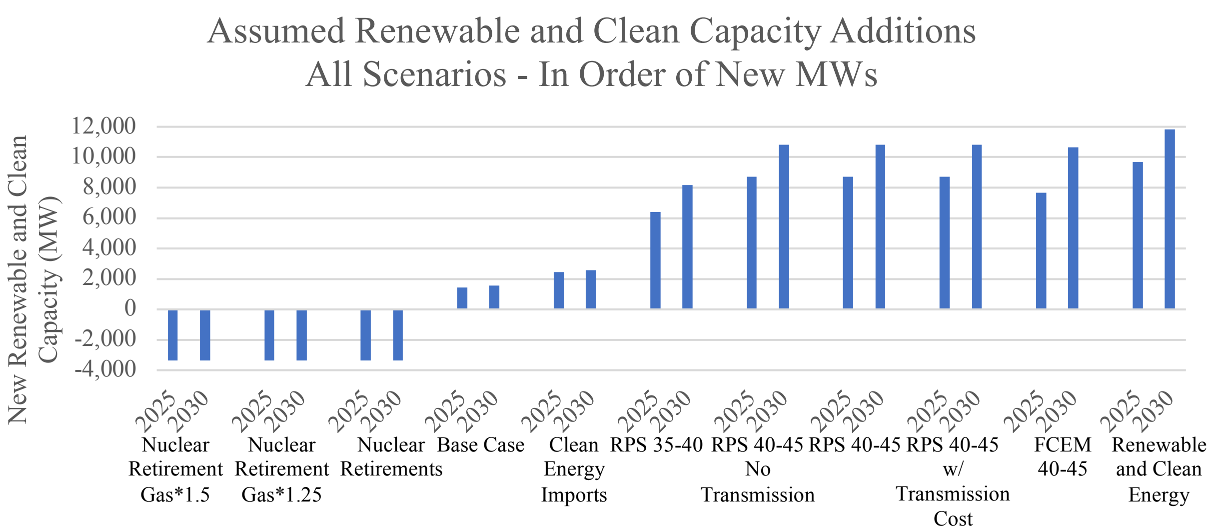
[84] *See*, for example, Cicala, S., *Imperfect Markets Versus Imperfect Regulation in U.S. Electricity Generation*, National Bureau of Economic Research Working Paper No. 23053 (January 2017), available at http://www.nber.org/papers/w23053. See also Kahn, A. et al., *Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond*, Electricity Journal (July 2001), available at ftp://cramton.umd.edu/papers2000-2004/kahn-cramton-porter-tabors-uniform-or-pay-as-bid-pricing-ej.pdf.

energy resource penetration increases, the relative cost variation from mechanism to mechanism is smaller than the cost increases that occur due to the shift away from energy and capacity market revenues and toward mechanism-based revenues, as shown below.

### b. Resource Additions and Consumer Costs

The modeling results that inform consumer costs in this analysis are driven by the hypothetical future scenario assumptions regarding a cleaner resource mix. The scenario assumptions are presented, for information, from left to right in the order of renewable and clean energy resource additions in Figure 14 below. For example, on the far left are the Nuclear Retirements scenarios. These assumed approximately 3,350 MW of clean energy resources less than the Base Case. In the middle is the Base Case scenario. This represents an extension of the status quo. On the far right, the Combined Renewable and Clean Energy scenario assumed approximately 8,250-10,250 MW of additional renewable and clean energy resources more than the Base Case.

**Figure 14: Scenarios and New Resource Assumptions**




As a reminder, Phase I found that as the model "adds new renewable generating resources or additional clean energy imports to the New England system, those added resources have the effect of decreasing the amount of money that all existing resources earn from New England's capacity and energy markets."[85] Specifically, assumed additional new renewable and clean energy resources "drive energy market prices lower than what they would be under the status quo and capacity prices also decline, temporarily. That decline is due to excess supply; capacity prices rebound in later years. Together, energy and capacity market price declines cause resources' 'missing money' to increase."[86] Figure 15 below shows the impact of the new resource assumptions on wholesale energy and capacity consumer costs, which are the flip-side of resources' wholesale energy and capacity revenues. As the penetration of renewable and

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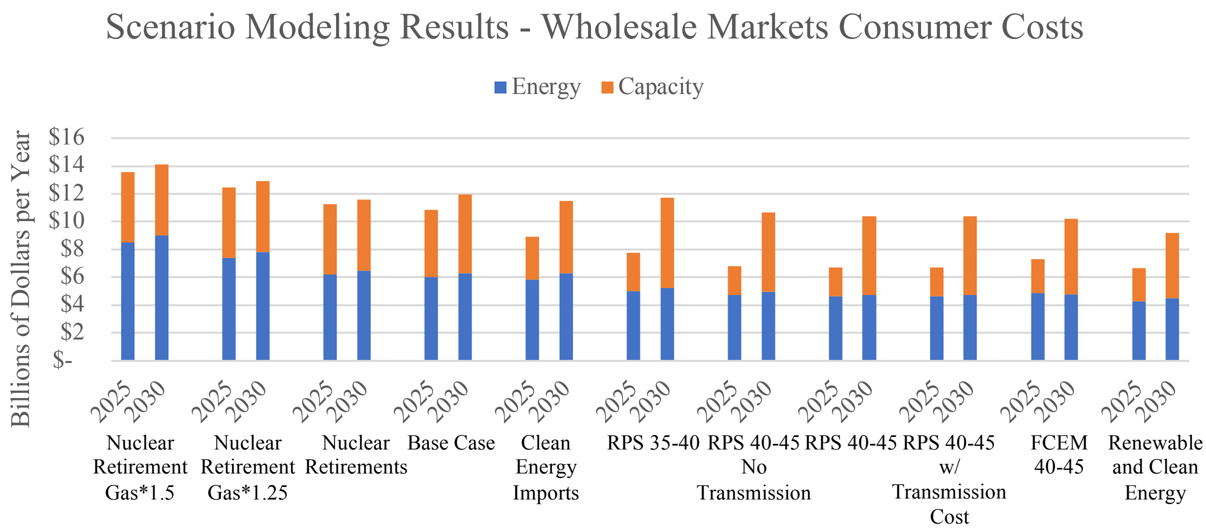
85 Phase I Report at 3.

86 Phase I Report at 2.

clean energy increases, moving left to right on the chart, wholesale market revenues and thus consumer costs decrease.

**Figure 15: Wholesale Energy and Capacity Costs Across All Scenarios**




In addition to the customer costs for energy and capacity, Figure 16 below presents the costs associated with achieving each scenario's renewable and clean energy requirements through a common mechanism. This example shows the mechanism cost for an RPS with only one tier and no ACP.[87] Figure 16 demonstrates how consumer costs shift from energy and capacity to mechanism costs as the clean energy penetration increases.

[87] The mechanism design RPS with only one tier and no ACP represents an approach that was applied to all scenarios, conservatively estimates consumer costs (one tier and no ACP to control consumer costs) and achieves the target with attributes (not ACPs). For these reasons, it provides a reasonable example of customer costs associated with mechanisms, before the complexity of various design elements are introduced below.

**Figure 16: Energy, Capacity, and Representative Mechanism Costs Across Scenarios**

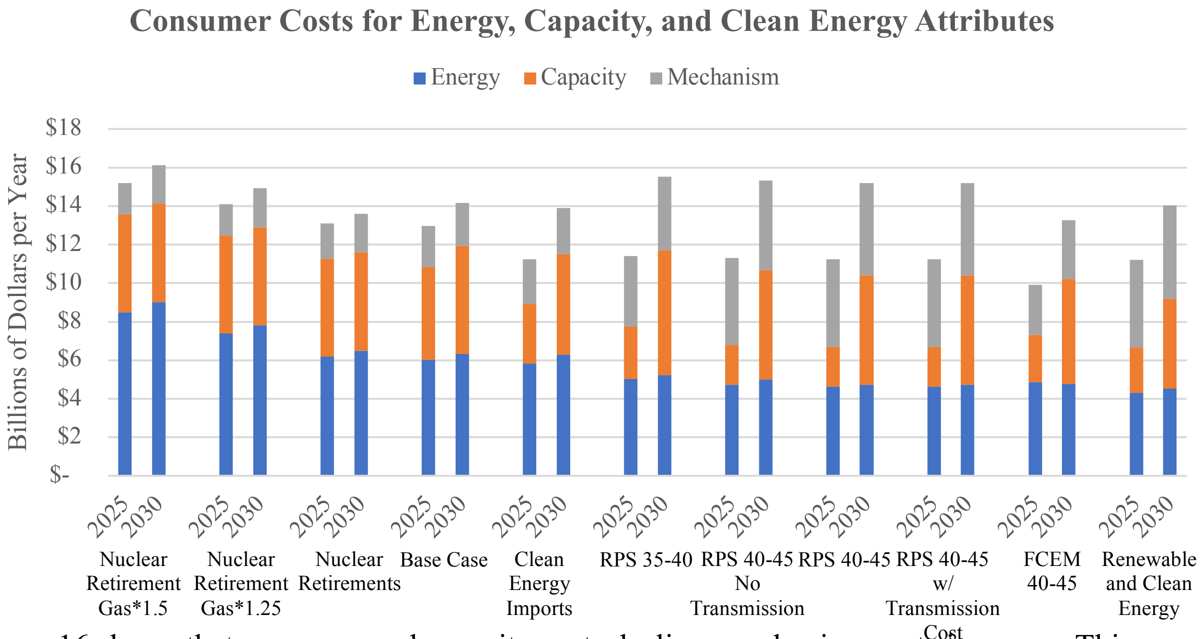



Figure 16 shows that as energy and capacity costs decline, mechanism costs increase. This illustrates the relationship between wholesale market revenues and "missing money." Specifically, as resources eligible for these mechanisms earn less money from the energy and capacity markets, mechanism revenues must increase to make up the difference. In addition, total costs to consumers decline *temporarily* with the decrease in capacity costs, shown by columns corresponding to the 2025 results. Once capacity costs rebound in 2030, total costs to consumers increase modestly relative to the Base Case.[88]

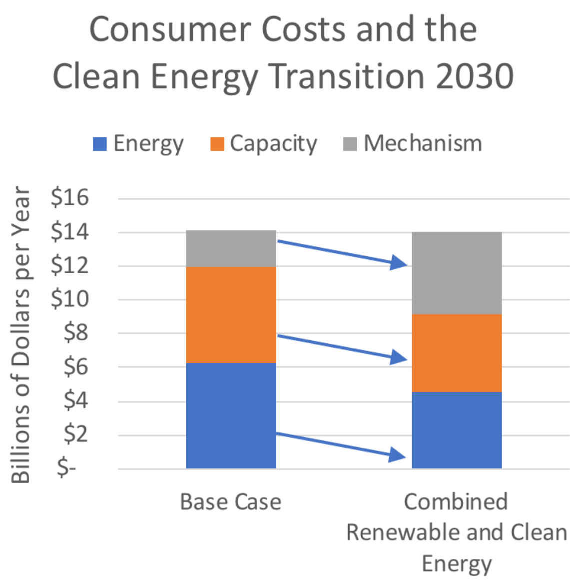
The figure also illustrates that: (1) the amount of customer costs shifted (from the Base Case to the Renewable and Clean Energy scenario on the far right) from the energy and capacity markets to the mechanism is on the order of approximately $2 billion, and (2) the total consumer costs remain somewhat stable from scenario to scenario (approximately $11 billion in 2025 and approximately $14 billion in 2030).

The approximately $2 billion shift from market-based costs to mechanism-based costs is a benchmark for comparing the cost impacts of mechanism design changes, discussed below. The RPS 35-40% and RPS 40-45% scenarios (and its variations such as without transmission and allocating the costs of transmission to the new on-shore wind) are the most expensive total consumer cost. This is because of the increase in penetration of higher cost resources required to meet state objectives. They have similar costs because the single market price is set by the same new off-shore wind resource.

The FCEM 40-45% scenario has some of the lowest total consumer costs because it includes more imported hydropower and excludes new off-shore wind (LEI projects this resource to set the single market price in the years after 2030 when costs for this new technology have declined).

88 For more information on the temporary decline in capacity price in the Phase I: Scenario Analysis, *see* Phase I report at pp. 26-28.

**Figure 17: Illustration of the Shift in Customer Costs from Markets to Mechanisms**




The relatively stable total consumer costs across the scenarios in Figure17 to the left shows the shift in costs from the energy and capacity markets to the mechanisms analyzed. This relationship is further highlighted by examining two scenarios – the Base Case and the Renewable and Clean Energy Scenario. The Base Case represents an extension of the status quo. The Renewable and Clean Energy scenario is the most aggressive hypothetical future scenario. The 2030 values mitigate the impact of temporary capacity price declines that result from oversupply. As shown in Figure 17, when more new renewable and clean energy resources are added, energy and capacity revenues decline, and mechanisms costs increase.

### 2. Mechanism Design Cost Impacts

This section presents cost information associated with mechanism design elements. This section highlights the degree to which design choices influence consumer costs. First, the estimated mechanism customer costs are presented for representative versions of the RPS, CES, Long-Term Contracts, and FCEM for all scenarios.[89] Next, costs associated with several design approaches are presented.

Figure 18 below presents customer costs for (1) mechanisms for each scenario from the Phase I: Scenario Analysis and (2) the additional FCEM 40-45% scenario. The mechanism cost comparison is based on various design approaches for each mechanism.

- The RPS design includes one tier for all new renewable resources with costs capped at the assumed hypothetical future ACP values. Not all states have a one-tiered RPS and ACP values differ across the region. *Thus, the analysis is directionally indicative only.*
- The CES design includes three tiers: (1) new and existing clean energy resources (imported hydro and nuclear), (2) new renewable resources with costs capped at the ACP,

[89] As a reminder, scenarios are hypothetical future power system conditions, most notable in this study for increasing amounts of new renewable and clean energy resources. Mechanisms are various approaches to support resources capable of helping states achieve renewable and clean energy requirements. Scenarios and mechanisms are not the same. Different scenarios result in different amounts of missing money. Eligible resources use mechanism revenues to recover missing money. Also, mechanisms can be designed many ways (i.e., tiers, ACPs, etc.). The possible combinations of scenarios, mechanisms, and mechanism design elements combination can get complicated quickly.

and (3) carve-outs for solar and off-shore wind resources with no ACP. There are various other ways to design a CES.[90]

- The Long-Term Contract design includes costs associated with each resource type's missing money and a three percent (3%) adder for utility balance sheet impacts associated with each contract.[91] Adders for utilities are not uniform across state laws.
- The FCEM design includes one tier for all new renewable and clean energy (imported hydro over new transmission) resources. In light of the conceptual status of the FCEM, this presentation is illustrative.[92]

**Figure 18: Representative Mechanism Costs Across All Scenarios**

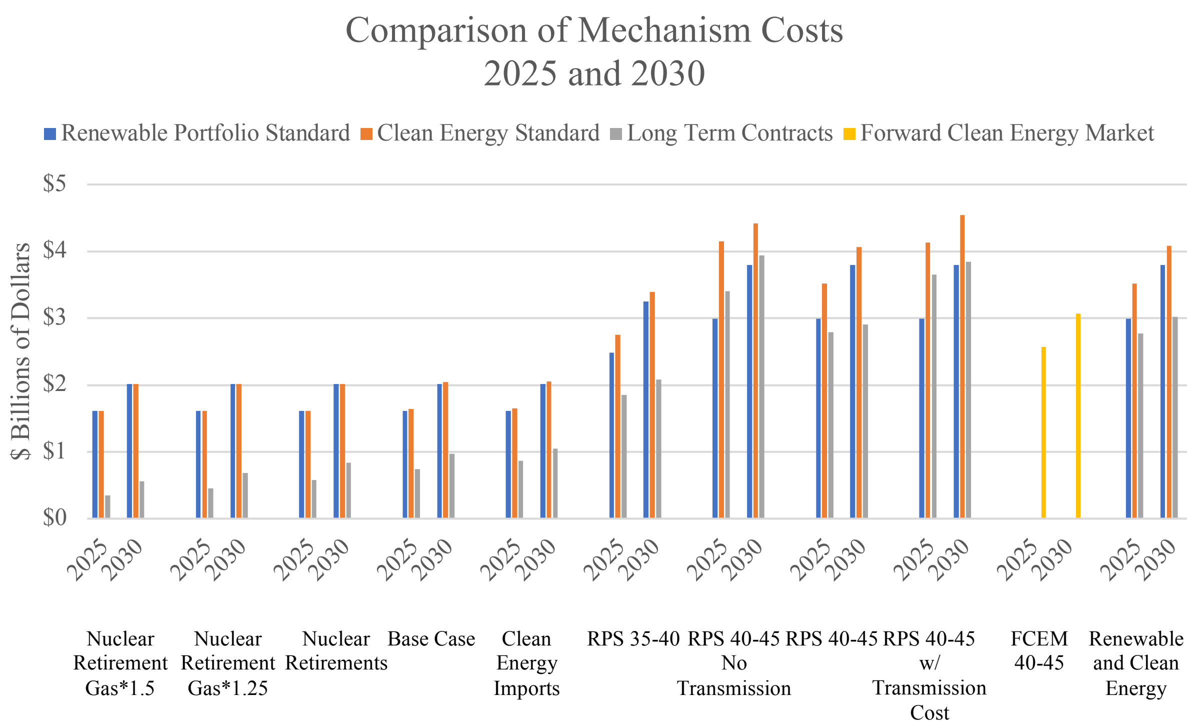



Figure 18's comparison of mechanism costs, above, further illustrates the relationship between energy and capacity revenues and "missing money." As new renewable and clean energy are

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90 The three-tiered CES design here has conceptual similarities to the New York CES design objectives: first tier for growth in new renewables, a second tier for the maintenance of existing renewables and/or mature technologies, and a third tier to support clean energy resources.

91 Pursuant to Sections 83, 83A, 83B, 83C, and 83D of An Act Relative to Green Communities, St. 2008, c. 169 (as amended by St. 2012, c. 209 and St. 2016, c. 188), Massachusetts regulations law provides for annual remuneration for the contracting distribution company up to 2.75% (§§83A-D) to 4% (§83) of the annual payments under the contract to compensate the company for accepting the financial obligation of the long-term contract.

92 For information, the FCEM 40-45% scenario established its new resource additions by reference to what would *likely clear in an FCEM* (imported hydro, then renewables in economic merit order, up to the 40-45% demand target), rather than *assumed* new resources as in all of the other scenarios. The FCEM mechanism (one tier, no ACP) is then used by eligible resources to recover missing money amounts and estimate mechanism consumer costs.

added to the system, from left to right on the chart, the amount of "missing money" for *all* resources increases, including resources that would help states meet statutory requirements. As shown above by the bars growing taller as "missing money" increases, the costs associated with mechanisms to support public policy resources increases. Figure 18 also shows the relationship between the costs of representative versions of RPS, CES, Long-Term Contracts, and FCEM.

While the costs of the representative mechanisms shown above differ, the cost difference between mechanisms is less than the amount that shifts from the energy and capacity markets to the mechanisms, approximately $2 billion. The difference in costs between the mechanisms shown above is less than half that amount. ***This suggests that the <u>level</u> of clean energy resources in the region's resource mix has a greater influence on consumer costs associated with renewable and clean energy requirements than does the mechanism used to achieve states' renewable and clean energy requirements***.

In addition, the difference in costs between the mechanisms is partially explained by the scenario assumptions. All of the scenarios except the FCEM 40-45% scenario include additional offshore wind resources. This resource type sets the single market price for the RPS and CES mechanisms. In contrast, the FCEM 40-45% scenario included greater levels of lower cost resource types such that additional offshore wind resources were not required to meet the assumed clean energy requirement. This results in a lower cost estimate.

Also, the cost of transmission to deliver new on-shore wind is not evident in Figure 18 above. The transmission costs were significant, however. New on-shore wind including the costs of transmission is estimated to be less expensive than new off-shore wind in the scenario. Both the new off-shore wind and new on-shore wind with transmission costs exceeded the assumed ACP values. Since (a) new off-shore wind set the single market price for mechanisms without an ACP in all but one scenario and (b) the ACP set the single market price for the mechanisms with an ACP, the transmission costs do not make a significant difference in mechanism costs. The remaining difference in mechanism costs are attributable to price factors discussed above and the mechanism design elements examined further below.

Figure 19 below presents mechanism cost estimates associated with various design approaches for RPS, CES, Long-Term Contracts, and FCEM. As discussed above, RPS and CES use classification systems (e.g., classes or tiers) to ensure resource diversity and to provide different levels of compensation to different groups of resources (i.e., new versus existing). Similarly, carve-outs are used within classes to tiers to further diversify eligible resources. These mechanisms also generally have an ACP to limit their costs.

In this analysis, costs are estimated for several different design approaches – for example, the number of tiers and associated resource eligibility, with and without carve-outs, and with and without ACPs. Costs for Long-Term Contracts were estimated with and without a three percent (3%) adder. Figure 19 below presents cost estimates associated with each of these mechanism design variations for each of the scenarios in Phase I for 2025 and 2030.

**Figure 19: Range of Mechanism Cost Estimates**

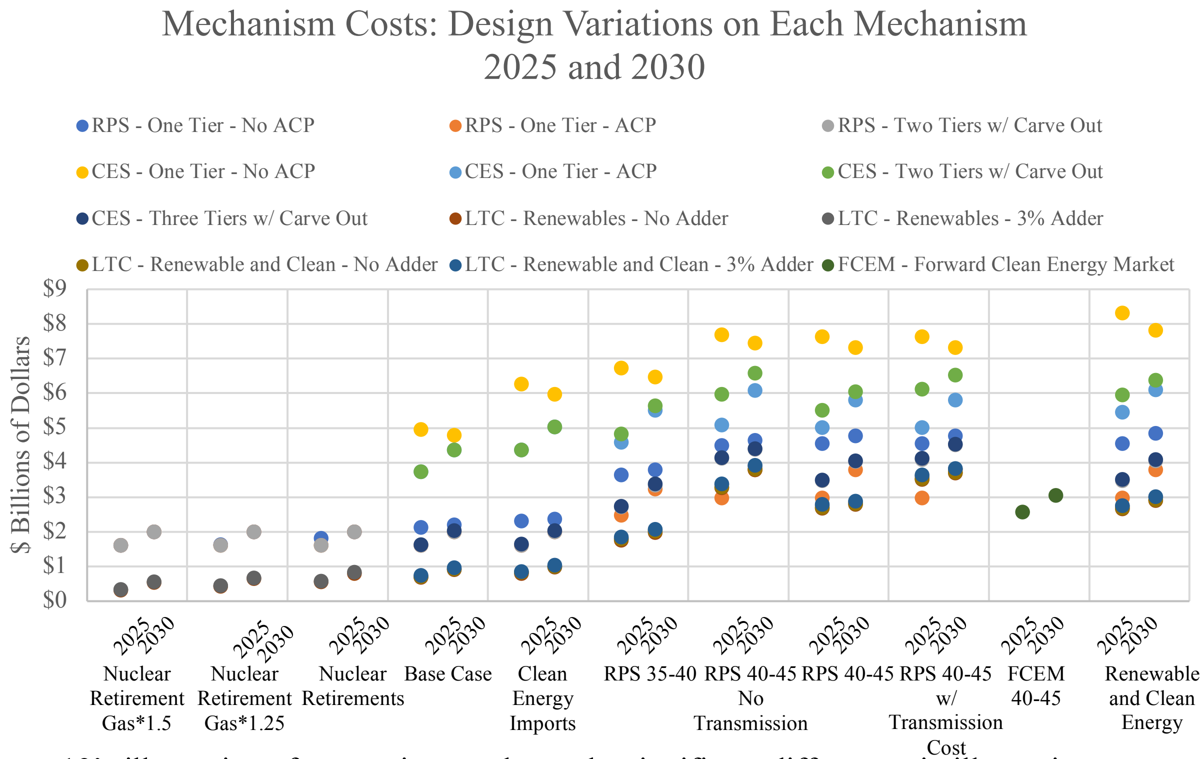


Figure 19's illustration of cost estimates shows the significant differences in illustrative costs associated with differences in mechanism design. As the amount of assumed renewable and clean energy resource additions increases, the differences in illustrative costs increases. Also, mechanisms with fewer tiers and no ACP (the green and yellow dots) showed consistently material increases across all scenarios. For example, mechanisms applied to: (1) the Base Case scenario range from approximately $0.5 to $5 Billion, and (2) the Renewable and Clean Energy scenario range from approximately $3 to $8.5 Billion.

The CES with one tier and no ACP is the most expensive design according to the analysis because it: (1) applies a uniform price to all eligible resources, (2) includes the greatest amount of resources (includes nuclear and new imported hydropower in certain scenarios), and (3) does not apply an ACP to control costs. Increasing the number of classes (or tiers) to the RPS and CES results in lower total mechanism costs.

Applying an ACP also reduces illustrative mechanism costs, but in the Phase I results some new renewable resources and associated transmission additions exceeded the ACP. This result suggests that, in practice, an ACP may help control mechanism costs as intended, but may also result in states not getting the greatest amount of actual renewable and clean energy resource built and placed into service.

Figure 19 highlights the potential cost impacts of various design considerations. Thus, whether a given mechanism achieves states' renewable and clean energy requirements at the lowest possible price over the long term depends on a state's design choices.

### *C. Power Sector Carbon Dioxide Emissions and Mechanism Costs*

The Phase I results show decreases in power sector $CO_2$ emissions relative to the Base Case that are associated with increasing amounts of new renewable and clean energy resources. The Phase I results also show increased power sector $CO_2$ emissions relative to the Base Case from assumed retirements of the remaining nuclear facilities in New England.

These results demonstrate that adding new renewable and clean energy resources while retaining existing clean energy resources lowers power sector carbon dioxide emissions. Mechanisms that add and retain renewable and clean energy resources therefore cause greater power sector emissions reductions.

The cost of such indirect emissions reductions can be estimated by comparing mechanism costs to emissions reductions levels, relative to the Base Case scenario. Specifically, dividing the average cost of RPS, CES, and Long-Term Contracts (discussed above) by the $CO_2$ emissions reductions yields an implied cost of $CO_2$ reduction for each of the scenarios for Phase I.[93] Figure 20 below presents the implied costs of Phase I power sector carbon dioxide ("$CO_2$") emission reductions. The trend line presented below represents the power sector $CO_2$ emissions levels.

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93 This concept is similar to the so-called marginal abatement cost metric. For more information on marginal abatement costs, *see* U.S. Environmental Protection Agency, *Tools of the Trade: A Guide to Designing and Operating a Cap and Trade Program for Pollution Control* (June 2003), available at https://www.epa.gov/sites/production/files/2016-03/documents/tools.pdf.

**Figure 20: Avoided Carbon Emissions and Mechanism Costs**

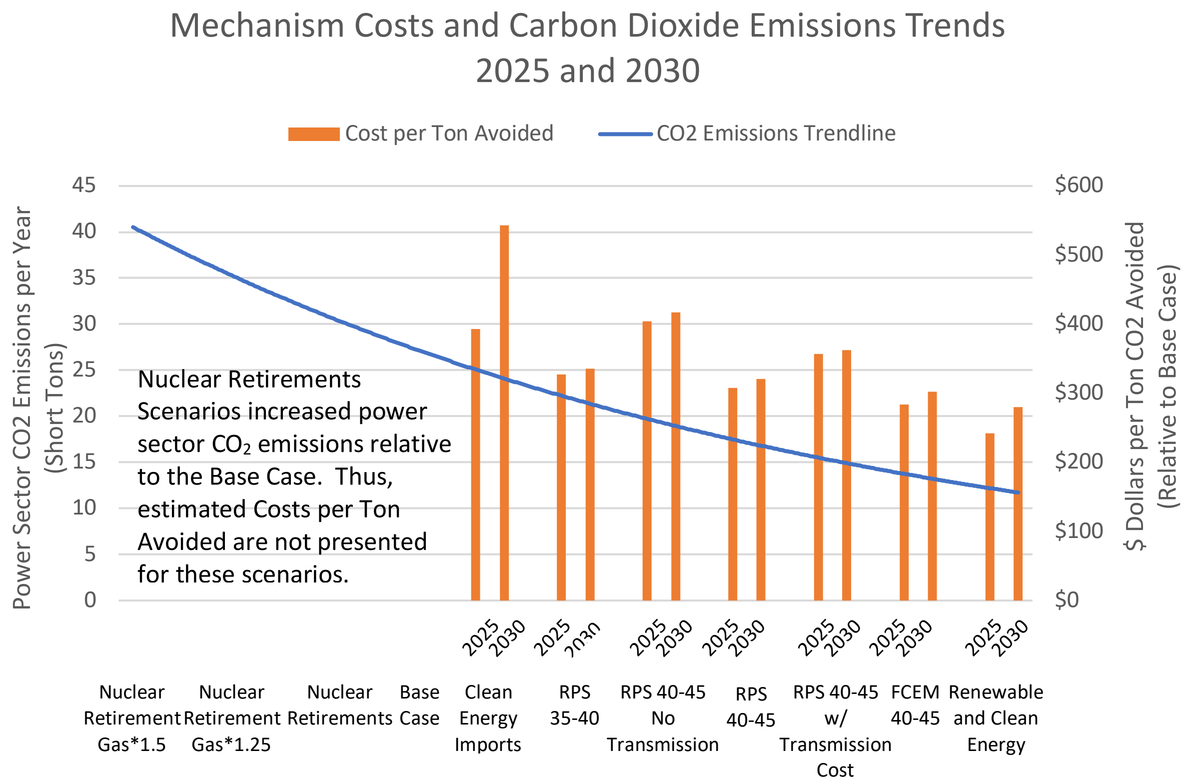


Figure 20 shows that the cost of avoiding power sector CO2 emissions declines slightly as new renewable and clean energy resources are added to the New England power system. This result is mostly due to the decreases in power sector CO2 emissions from the Phase I analysis. As shown above, average mechanism costs increase as the scenarios add more new renewable and clean energy. The calculated cost-per-ton of avoided emissions declines in this analysis because the rate of power sector emissions goes down faster than average mechanism costs go up. Thus, to the extent that additional renewable and clean energy resources are capable of achieving power sector emissions reductions, there may be slight reductions in the cost-per-ton avoided at increasing levels of penetration, assuming that the remaining nuclear resources in New England remain operational.

# IX. Key Observations

**Whether one or more mechanisms may better serve consumers than another depends on a state's objectives and the trade-offs a state is interested in making.**

- ***A preference for direct or indirect financial support?*** The RPS, CES, FCEM, and Long-Term Contracts provide revenues to generation resources. Consumers pay these resources to produce power and/or create certificates for the power's attributes. In contrast, Strategic Transmission Investments may reduce some costs that these resources would normally incur, but do not provide revenues directly to these resources. Strategic Transmission Investments indirectly benefit public policy resources by lowering barriers to entry in electricity markets and by enabling increased scales of production.

- ***Allocation of risk with project developers or consumers?*** RPS, CES, and FCEM maintain the balance of investment risk associated with competitive wholesale markets. Long-Term Contracts establish prices consumers will pay over the contract term at the time the contract is approved. Those prices may not reflect changes in market fundamentals or changes in resource costs over the life of the contract. For project developers, Long-Term Contracts' comparative revenue stability presents less investment risk than RECs or ZECs.

- ***Prioritization of cost control or resource diversity?*** Fewer resource classifications (i.e., classes or tiers) tend to result in a more homogenous resource mix that includes the lowest cost resource type. More classifications or carve-outs tend to result in greater resource diversity, but also higher relative costs due to more expensive resource types in the mix. An ACP is intended to control costs but could result in fewer actual megawatt hours of production if resource costs rise above ACP levels. Other design considerations (e.g., vintage, renewable fuel source versus clean emissions profile) affect consumer costs associated with mechanisms to support public policy.

- ***Importance of diversity of resource types, operating characteristics and locations?*** RPS, CES, and FCEM would likely result in the greatest diversity of resource types, sizes, operating characteristics and locations on the power system. Long-Term Contracts are more likely to result in one or a defined number of resources operating on one or several locations over a finite period.

- ***Interaction with wholesale markets?*** RPS, CES, and Long-Term Contracts provide revenues to resources without regard to the then-current short-term electric energy market prices (e.g., hourly real-time prices). A version of the FCEM may provide greater revenues at times and in locations where power system emissions are relatively higher. Alternatively, Strategic Transmission Investments have little to no impact on energy market price formation. Strategic Transmission Investments may also enable greater competition among resources, which generally improves wholesale markets' economic efficiency.

**Wholesale energy and capacity costs move in the opposite direction from mechanism costs, and both directly affect consumer bills.**

- ***As energy and capacity costs decline, mechanism costs increase***. As resources eligible for public policy mechanisms earn less money from the energy and capacity markets, consumers must fund increased mechanism revenues to make up the difference.

- ***Temporary capacity cost declines have a significant impact on total costs to consumers.*** Total costs to consumers (energy plus capacity plus average mechanism cost) decline temporarily with the decrease in capacity costs. Once capacity costs rebound, total costs to consumers increase modestly.

- ***"Missing Money" increases outweigh the difference in estimated cost among mechanisms.*** In general, the RPS, CES, and FCEM appear to cost more than the Long-Term Contracts in this analysis. This is primarily due to the RPS, CES, and FCEM paying all resources within a tier the same price – the price associated with the most expensive resource against which each resource competes. The Long-Term Contracts mechanism appears less expensive than the RPS, CES, and FCEM mechanisms because each resource type is paid the corresponding amount of missing money.[94] Importantly, the difference in mechanism costs is much less than the aggregate level of "missing money" increases associated with energy and capacity revenue declines.

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94 This result highlights what is known in economist terms as the "uniform price" versus "as bid" debate. Whether one approach costs more over time is discussed at length in the economic literature. For example, *see* Tierney, S. et al., *Pay-as-Bid vs. Uniform Pricing: Discriminatory auctions promote strategic bidding and market manipulation* (March 2008), available at https://www.fortnightly.com/fortnightly/2008/03/pay-bid-vs-uniform-pricing.

## Appendix A: Renewable and Clean Energy Target Estimation and Alternative Compliance Payments

To evaluate the RPS and CES mechanisms, the Study assumes future targets for renewable and clean energy and an Alternative Compliance Payment ("ACP"). To evaluate a scenario's outlook for RPS and CES compliance, it is necessary to estimate the amount of renewable energy certificates that will be required in two future years. In short, the values are based on forecasted demand for wholesale electricity and an estimate of the approximate amount of energy associated with RPS targets, both under current law and hypothetical expanded targets. In addition, to evaluate the potential costs of these mechanisms under a variety of configurations, an estimate of the ACP amount is required. This appendix explains how these values are estimated in the study and walks the reader through the calculations.

### 1. Forecast the Demand for Wholesale Electricity

#### a) Gross Load Forecast

According to the 2016 ISO New England Capacity, Energy, Loads, and Transmission ("CELT") Report, the gross load forecast (Regional Net Energy for Load) is expected to be:

| | 2025 (GWh) | 2030 (GWh) |
|---|---|---|
| **Gross Load Forecast** | 152,731 | 158,985 |

#### b) Energy Efficiency and Behind the Meter Solar PV

According to the same 2016 CELT Report, the estimated wholesale load reductions associated with energy efficiency (EE, or Passive Demand Resources) and behind-the-meter solar photovoltaic resources (PV, or BTM Solar PV) are:

| | 2025 (GWh) | 2030 (GWh) |
|---|---|---|
| **Energy Efficiency** | 24,559 | 31,304 |
| **BTM Solar PV** | 2,959 | 3,574 |

#### c) Net Wholesale Load Forecast

Based on the forecasted estimates above, the net wholesale load forecast is calculated to be equal to the gross load forecast minus the EE and BTM Solar PV.

| | 2025 (GWh) | 2030 (GWh) |
|---|---|---|
| **Gross Load Forecast** | 152,731 | 158,985 |
| minus **Energy Efficiency** | 24,559 | 31,304 |
| minus **BTM Solar PV** | 2,959 | 3,574 |
| equals **Net Load Forecast** | 125,213 | 124,097 |

### 2. RPS Target Percentages

The RPS is expressed as a percentage of energy consumption in all six New England states. There are several tiers in each state's RPS that correspond to different eligibility criteria based on resource type and vintage. While there are differences across the states in the number of tiers and associated eligibility, a common theme is the targeting of specific tiers for: (a) growth in new resources and (b) maintenance of existing resources. Given this commonality, it is possible to aggregate the individual state RPS targets for new and existing resources. A spreadsheet developed by ISO-NE in 2012, and subsequently updated in 2016, enables calculation of these targets.[95]

In general, the existing "maintenance" tiers are added to the new "growth" tiers to arrive at the total RPS percentage target. The graphic below illustrates the relationship between the existing and new RPS tiers to arrive at the total RPS percentage.

**Figure 21: Total RPS Percentage Calculation**


In the table below, RPS percentages are expressed as the sum of aggregated regional RPS demand for new and existing renewable resources, which is applied to the net load forecast derived in the calculation above to estimate the amount of required energy (in GWh) necessary to be generated in aggregate by renewable sources in two future years. The classifications for new and existing are based on the concept of "growth" and "maintenance tiers," respectively. Accordingly, the amounts shown in the tables below generalize the various RPS tier and carve-out designs into "New" and "Existing."

### a) Current, Effective Regional RPS Percentage

**Table K: Effective Regional RPS Under Current Law**

| | 2025 | | 2030 | |
|---|---|---|---|---|
| | **%** | **GWh** | **%** | **GWh** |
| **Current Law – Existing RPS** | 10.18% | 12,747 | 10.27% | 12,748 |
| **Current Law – New RPS** | 16.10% | 20,160 | 18.44% | 22,881 |
| (Sum) **Current Law – Existing and New RPS** | **26.28%** | **32,907** | **28.71%** | **35,629** |
| **Net Load Forecast** | 100% | 125,213 | 100% | 124,097 |

As shown in the table above, the effective regional RPS targets under current law are 26.28% in 2025 and 28.71% in 2030.

### b) Hypothetical Expanded RPS Percentages

The Study assumes an expanded RPS as part of the scenario analysis. The Expanded RPS Scenario includes two different levels of RPS expansion: (1) 35% by 2025 and 40% by 2030

95 The 2016 RPS Spreadsheet is available at https://www.iso-ne.com/static-assets/documents/2016/05/a3_2016_economic_study_scope_of_work_rps_spreadsheet.xlsx.

("35-40") and (2) 40% by 2025 and 45% by 2030 ("40-45"). Thus, the two different levels of hypothetical RPS expansions in the scenario analysis are labeled: Expanded RPS 35-40 and Expanded RPS 40-45.

#### c) Note on New vs. Existing

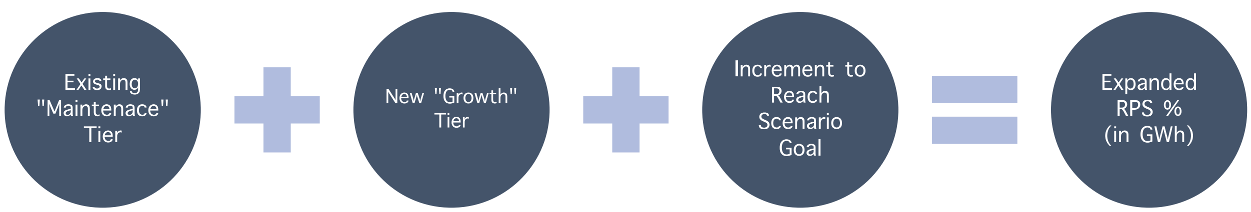
To illustrate the interactions between the RPS mechanism and the wholesale electricity market, the Study's analysis of the RPS mechanism focuses on growth in new renewable resources.[96] Therefore, the RPS targets associated with new renewable resources are used to illustrate the functioning of the RPS mechanism. The new renewable resource targets are expanded to reflect the increase in RPS targets in the two Expanded RPS scenarios.

### 3. RPS Target Energy Amounts

#### a) Apply RPS Target Percentages

The Expanded RPS Scenario includes two different levels of RPS expansion: (1) 35% by 2025 and 40% by 2030 ("35-40") and (2) 40% by 2025 and 45% by 2030 ("40-45"). The amounts of energy associated with those hypothetical RPS expansions are calculated below. Note that the increment needed to reach the scenario goal is the "unknown" term in the equation that is being solved for, below.

**Figure 22: Expanded RPS Percentage Calculation**




[96] Other mechanisms (e.g., Clean Energy Standard) are designed to enable retention of existing nuclear and addition of new clean energy imports.

**Table L: 35-40 RPS Targets and Associated Energy Amounts**

| | 2025 | | 2030 | |
|---|---|---|---|---|
| | **%** | **GWh** | **%** | **GWh** |
| **Current Law – Existing RPS** | 10.18% | 12,747 | 10.27% | 12,748 |
| **Current Law – New RPS** | 16.10% | 20,160 | 18.44% | 22,881 |
| **35-40 Expanded RPS – Additional New RPS** | 8.72% | 10,918 | 11.29% | 14,010 |
| (Sum) **Current Law – Existing and New RPS and 35-40 Expanded RPS – Additional New RPS** | **35%** | **43,825** | **40%** | **49,639** |
| **Net Load Forecast** | 100% | 125,213 | 100% | 124,097 |

**Table M: 40-45 RPS Targets and Associated Energy Amounts**

| | 2025 | | 2030 | |
|---|---|---|---|---|
| | **%** | **GWh** | **%** | **GWh** |
| **Current Law – Existing RPS** | 10.18% | 12,747 | 10.27% | 12,748 |
| **Current Law – New RPS** | 16.10% | 20,160 | 18.44% | 22,881 |
| **40-45 Expanded RPS – Additional New RPS** | 13.72% | 17,178 | 16.29% | 20,215 |
| (Sum) **Current Law – Existing and New RPS and 40-45 Expanded RPS – Additional New RPS** | **40%** | **50,085** | **45%** | **55,844** |
| **Net Load Forecast** | 100% | 125,213 | 100% | 124,097 |

### b) Focus on New Renewable Resource Targets

As described above, the Study's evaluation of the RPS mechanism focuses on new renewable resources. To align the Study's focus on the growth in new renewable resources, it is necessary to estimate the total amount of RPS mechanism-eligible new renewable resources that would be required to meet the targets in the expanded scenarios. The new renewable energy targets are equal to the sum of the current law's new RPS and the hypothetically expanded RPS target's incremental renewable energy. As shown in the table below, this amount is calculated for both the 35-40 and 40-45 RPS scenarios.

**Figure 23: Expanded RPS Scenarios – New Renewables Targets Calculation**


**Table N: 35-40 RPS – New Renewable Energy Targets**

| | 2025 | | 2030 | |
|---|---|---|---|---|
| | **%** | **GWh** | **%** | **GWh** |
| **Current Law – New RPS** | 16.10% | 20,160 | 18.44% | 22,881 |
| **35-40 Expanded RPS – Additional New RPS** | 8.72% | 10,918 | 11.29% | 14,010 |
| (Sum) **Current Law – New RPS and 35-40 Expanded RPS – Additional New RPS** | **24.82%** | **31,078** | **29.73%** | **36,891** |
| **Net Load Forecast** | 100% | 125,213 | 100% | 124,097 |

**Table O: 40-45 RPS – New Renewable Energy Targets**

| | 2025 | | 2030 | |
|---|---|---|---|---|
| | **%** | **GWh** | **%** | **GWh** |
| **Current Law – New RPS** | 16.10% | 20,160 | 18.44% | 22,881 |
| **40-45 Expanded RPS – Additional New RPS** | 13.72% | 17,178 | 16.29% | 20,215 |
| (Sum) **Current Law – New RPS and 40-45 Expanded RPS – Additional New RPS** | **29.82%** | **37,338** | **34.73%** | **43,096** |
| **Net Load Forecast** | 100% | 125,213 | 100% | 124,097 |

### c) Expanded RPS Scenarios – Target Energy Amounts

For the reader's convenience, the table below presents the results of the preceding calculations: the target amounts of RPS mechanism eligible energy for the two Expanded RPS scenarios.

**Table P: Expanded RPS Scenarios - New Renewable Energy Targets**

| | 2025 | 2030 |
|---|---|---|
| | GWh | GWh |
| 35-40 Expanded RPS – Total New RPS-eligible Energy | 31,078 | 36,891 |
| 40-45 Expanded RPS – \|Total New RPS-eligible Energy | 37,338 | 43,096 |

### 4. Alternative Compliance Payments

As discussed above, the RPS creates an obligation on retail electricity providers to (1) purchase RECs that are produced in proportion to the energy consumed by their customers from qualifying resources, or (2) pay a penalty fee, also known as an Alternative Compliance Payment ("ACP).[97] Retail electricity providers have the option to pay an ACP rather than buying RECs.[98] The ACP is a means of RPS compliance in two cases: 1) in the event that the supply of RECs is inadequate to meet the standard or 2) when RECs become too expensive. The price of the ACP is usually set through a legislative or regulatory process and represents a limit on the "potential burden on ratepayers."[99] The theory behind the ACP is that states desire to satisfy RPS requirements, but not at any cost. States usually direct that ACPs paid in a given compliance period be used to support renewable and other clean energy development loan funds.[100]

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97 *See* also *Mechanisms to Support Public Policy Resources in New England* (December 2015), at 15 and 18, available at http://nescoe.com/resource-center/mechanisms-dec2015/.

98 Other cost containment mechanisms include rate impact/revenue requirement caps, surcharge caps, renewable energy contract price caps, renewable energy funding caps, and financial penalties. Heeter, J. et al., *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards* (May 2014), at 45-46, available at http://www.nrel.gov/docs/fy14osti/61042.pdf.

99 *Id.* at 45.

100 For more information regarding use of ACP funds, see the latest annual program reports, available at: Connecticut • Massachusetts • Maine • New Hampshire • Rhode Island • Vermont. Vermont's Renewable Energy Standard goes into effect in 2017.

### a) Current ACPs

Pursuant to state statute, the ACP in Connecticut is $55 per megawatt-hour.[101] In Massachusetts, the 2016 ACP is $66.99.[102] In Maine, the 2016 ACP is $67.00.[103] In New Hampshire, the 2016 ACP is $55.72.[104] In Rhode Island, the 2016 ACP is $67.00.[105] Vermont's version of the RPS, the Renewable Energy Standard, goes into effect in 2017. Pursuant to state statute, the distributed generation ACP will be $60/MWh.[106] The chart below shows the same information for the six New England states.

**Table Q: Alternative Compliance Payments in New England**

| | Connecticut | Massachusetts | Maine | New Hampshire | Rhode Island | Vermont |
|---|---|---|---|---|---|---|
| 2016 | $55 | $66.99 | $67.00 | $55.72 | $67.00 | n/a |
| 2017 | TBD | TBD | TBD | TBD | TBD | $60.00 |

As shown in the chart above, three states have an ACP that is approximately $67.00 in 2016.

### b) Escalation for Inflation

Five of the six New England states annually adjust the ACP rate to reflect price increases in the general economy based on the U.S. Bureau of Labor Statistics Consumer Price Index ("CPI") or a variation of the CPI. For simplicity, the Study assumes an annual 2% increase in ACP rates to estimate what the ACPs across New England might be in 2025 and 2030. The chart below shows the impact of annually increasing ACPs by an assumed 2%.

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101 Connecticut Public Utilities Regulatory Authority, *Annual Review of Connecticut Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in the Year 2014,* Docket No. 15-09-18 (September 28, 2016), at 33, available at http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/d0409659caa9d2228525803c00531217?OpenDocument. See also, Conn. Gen. Stat. §16-244c(h)(1), available at https://www.cga.ct.gov/current/pub/chap_283.htm#sec_16-244c.

102 *See* Massachusetts Executive Office of Energy and Environmental Affairs' website at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/rps-aps/retail-electric-supplier-compliance/alternative-compliance-payment-rates.html.

103 *See* Maine Public Utilities Commission, *Renewable Portfolio Standard, Adjustment of the Alternative Compliance Payment Rate for Compliance Year 2016* (January 31, 2016), available at http://www.maine.gov/mpuc/electricity/electric_supply/documents/2016AlternativeComplaincePayment.pdf.

104 *See* New Hampshire Public Utilities Commission's website at http://www.puc.state.nh.us/Sustainable%20Energy/Renewable_Portfolio_Standard_Program.htm.

105 *See* Rhode Island Public Utilities Commission's website at http://www.ripuc.ri.gov/utilityinfo/RES-ACPRate.pdf.

106 Vermont Public Service Board, *Order Implementing the Renewable Energy Standard*, Docket No. 8550 (June 28, 2016), at 63 n. 43, available at http://psb.vermont.gov/sites/psb/files/8550 Final Order.pdf. *See* also 30 V.S. A. 8005(a)(4) at http://legislature.vermont.gov/statutes/section/30/089/08005.

**Table R: Hypothetical Future Alternative Compliance Payments in New England**

| | Connecticut | Massachusetts | Maine | New Hampshire | Rhode Island | Vermont |
|---|---|---|---|---|---|---|
| 2016 | $55 | $66.99 | $67.00 | $55.72 | $67.00 | n/a |
| 2017 | $56.10 | $68.33 | $68.34 | $56.83 | $68.34 | $60.00 |
| 2018 | $57.22 | $69.70 | $69.71 | $57.97 | $69.71 | $61.20 |
| 2019 | $58.37 | $71.09 | $71.10 | $59.13 | $71.10 | $62.42 |
| 2020 | $59.53 | $72.51 | $72.52 | $60.31 | $72.52 | $63.67 |
| 2021 | $60.72 | $73.96 | $73.97 | $61.52 | $73.97 | $64.95 |
| 2022 | $61.94 | $75.44 | $75.45 | $62.75 | $75.45 | $66.24 |
| 2023 | $63.18 | $76.95 | $76.96 | $64.00 | $76.96 | $67.57 |
| 2024 | $64.44 | $78.49 | $78.50 | $65.28 | $78.50 | $68.92 |
| **2025** | **$65.73** | **$80.06** | **$80.07** | **$66.59** | **$80.07** | **$70.30** |
| 2026 | $67.04 | $81.66 | $81.67 | $67.92 | $81.67 | $71.71 |
| 2027 | $68.39 | $83.29 | $83.31 | $69.28 | $83.31 | $73.14 |
| 2028 | $69.75 | $84.96 | $84.97 | $70.67 | $84.97 | $74.60 |
| 2029 | $71.15 | $86.66 | $86.67 | $72.08 | $86.67 | $76.09 |
| **2030** | **$72.57** | **$88.39** | **$88.41** | **$73.52** | **$88.41** | **$77.62** |

As shown in the chart above, hypothetical future ACPs range from $65.73 to $80.07 in 2025 and $72.57 to $88.41 in 2030.

### c) Hypothetical Future ACP Values for the Study

Hypothetical future ACP values are used in the Study's mechanism analysis as a "missing money" reference point and as a substitute for shortfalls in available renewable energy production. To set a price cap on renewable energy, the Study assumes ACP values that are toward the higher end of the forecasted range of hypothetical future ACPs. The chart below shows the assumed ACP values used in the mechanisms analysis of the study.

**Table S: Assumed Future ACP Values in the Study**

| Study Year | Assumed ACP Value |
|---|---|
| 2025 | $80 |
| 2030 | $88 |