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Appendix I

Incorporating Large-Scale Hydro into a Connecticut Class I RPS Sub-tier

A White Paper

The Connecticut Department of Energy

and Environmental Protection

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1 Overview

Section 129 of Public Act 11-80 requires the Department of Energy and Environmental Protection (DEEP) to analyze (1) options to minimize the cost to ratepayers of procuring renewable resources pursuant to section 16-245(a) of the Connecticut General Statutes, and (2) the feasibility of increasing the renewable standards. P.A. 11-80 called for the analyses to consider the benefits, costs and impacts of expanding the definition of Class I to include large scale hydropower.

Connecticut Governor Dannel P. Malloy and DEEP Commissioner Dan Esty have expressed interest in tapping large-scale, low-cost renewable energy supply sources, potentially consisting of newly developed hydroelectric resources. By doing so Connecticut could take and maintain a leadership position among states in securing a 'cheaper, cleaner, more reliable' electricity supply. The purpose of this white paper is to examine the range of alternatives for creating within the Connecticut Class I Renewable Portfolio Standard (RPS) a sub-tier that will apply procurement best practices to achieve this objective. The impetus for this potential policy change is the planned development of large-scale hydroelectric facilities in Eastern Canada, as well as Connecticut's aggressive greenhouse gas reduction goals established in Public Act 08-98.

This white paper will explore a mechanism referred to hereafter as the '**Large-Scale Hydro-Eligible Class I Sub-tier**' (or '**Contracted Class I Tier**' for short). The term will differentiate this category from today's RPS which will be termed the '**Market Class I Tier**'. The exploration below covers the various issues associated with developing, defining and implementing such a concept. It proceeds by outlining various issues, options to address the issue, and the advantages and limitations associated with options under consideration.

2 Objectives, Constraints and RPS Best Practices

A robust public policy analysis should be based on a foundation that frames the policy's objectives and the constraints within which it must operate. Any change in the State's RPS Class I mandate will benefit from consideration of applicable best practices as well.

2.1 Objectives

The primary objective of the Contracted Class I Tier is to minimize the cost of the RPS while providing comparable environmental benefits. The RPS Contracted Class I sub-tier would ideally meet the following objectives and thus have the characteristics presented in Table 1.

Table 1: Policy Objectives

Objective	Characteristics
Cheap	1) Resulting in little or no premium relative to projected cost of commodity electricity, including the anticipated costs of future increased regional/Federal greenhouse gas policies. 2) Minimizing consumers' exposure to the cost implications of RPS supply shortage (e.g. Alternative Compliance Payments, ACP).

Objective	Characteristics
Clean	1) Sourced from environmentally preferable renewable energy resources. 2) Contributes to meeting Connecticut's Global Warming Solutions Act targets. This characteristic triggers a need to consider additionality, described further below in Section 2.2. 3) Any RECs would be retained and retired in association with CT load to assure CT's unique ability to claim the supply procured towards renewables goals and greenhouse gas targets, but without payment of a premium.
Contracted	Procured via one or more a state-sponsored or mandated contracts. Procurement would be separate and distinct from current REC procurements of CT load-serving entities obligated under the Market Class I Tier.
Long-term	Provides price stability as a hedge against both natural gas price increases and future greenhouse gas requirements.
Competitively Procured	Provides competitive pressures on contracted price and transparency as appropriate for a public policy initiative.
Open to Large-scale hydro as well as other Class I-Eligible Supply	Supplied by energy, RECs and potentially capacity from renewable energy from resource(s) meeting either (i) the current RPS definitions or (ii) an expanded resource definition that also includes new (as of some specified vintage date) large-scale hydro with capacity greater than 5 MW. (While the impetus for this potential policy change is the planned development of large-scale hydroelectric facilities in Eastern Canada, as noted above, opening such supply up to competition from other generation sources capable of providing similar benefits represents good public policy.
Reliable	Achieves results that: 1) Do not degrade electric system reliability. 2) Do not impose on Connecticut or other regional ratepayers *unquantified* costs not considered in a cost-benefit context, such as increased transmission costs, operating reserve require requirements or reduced efficiency of other resources due to increased load-following requirements.[1] 3) Contribute towards meeting, reducing or mitigating impacts of the status quo on capacity reserve requirements, operating reserves, and peak energy usage.
Financeable	Backed by creditworthy purchasing entities or collections from ratepayers that are deemed reliable by financiers of the generation and transmission resources, in order to attract low-cost financing and assure the most attractive pricing.

2.2 Additionality

Because the underlying policy drivers – Renewable Portfolio Standards and the Global Warming Solutions Act – are intended to alter Connecticut's supply mix and reduce greenhouse gases, the concept of additionality is central to the credibility of the contemplated policy action. Additionality is the measurement of impact or net positive result of a policy intervention that would not have occurred in the absence of this action. (Scottish Enterprise, 2008) More generally, it takes into account changes

[1] While wind power, for example, could serve to meet these needs, direct savings would need to be sufficient to offset any such costs that are not internalized as part of the contract price.

in economic activity (i.e. scale, quality, pace, location) compared to a baseline scenario in which no action is taken.

In the greenhouse gas policy context, additionality is a key concept under the Kyoto Protocol, which provides that emission reductions shall be: *"... (b) Real, measurable and long-term benefits related to the mitigation of climate change; and (c)Reductions in emissions that are additional to any that would occur in the absence of the certified project activity."* (United Nations, 1998) The Clean Development Mechanism Rulebook notes that *"additionality is the requirement that the greenhouse gas emissions after implementation of a CDM project activity are lower than those that would have occurred in the most plausible alternative scenario to the implementation of the CDM project activity."* (Baker & McKenzie)

In the context of a **Contracted Class I RPS Tier**, additionality of the policy can be met (and with it, the justification for ratepayers to provide a cost premium or absorb the risk of a long-term contract commitment can be met) if:

1. *The contracted power supply is "incremental" or "new" beyond what had previously existed*. Benefit is achieved if the broader power supply portfolio is altered, renewables increase in proportion, and fossil fuel use and emissions are displaced. None of these benefits would be achieved if CT's procurement results solely in transferring existing renewable energy generation from one set of electricity consumers elsewhere to CT consumers, if the customers elsewhere were to replace the transferred supply through increased fossil fuel use.
2. *The future project would not happen in the absence of the policy*. One could argue that construction of generation projects fully committed in the absence of additional policy initiatives do not meet additionality criteria. With respect to this criterion, however, there are two potentially conflicting perspectives to consider, rendering the qualification subject to some less definitive, and more nuanced interpretation. For example, at various public events, representatives of Hydro Quebec or the Province of Quebec have represented both that the province is committed to proceed with major new hydroelectric development initiatives prior to any corresponding Power Purchase Agreement (PPA) with buyers in the United States, and that no premium payment over commodity electric supply prices would be required in such a PPA. If these representations are accurate, one might argue that a PPA with such facilities fails additionality criteria. On the other hand, even if committed plans exist to expand such hydroelectric capacity, the investment could be committed in order to accomplish increases in renewable energy generation and decreases in greenhouse gas emissions, in anticipation of supplying electric consumers in Connecticut and elsewhere. From this perspective, it may not be reasonable to penalize an early mover willing to take financial risk in advance of demand.[2]

New England has a substantial operating fleet of "legacy" renewable energy generators, built prior to electricity restructuring, consisting primarily of hydroelectric and biomass, as well as landfill gas to energy facilities. While not traditionally aligning with the concept of additionality, if generation

[2] New York wrestled with this notion in its RPS Main Tier eligibly, at one point excluding recently built wind generation that was already operating (and thus did not need their RPS contract to finance) from procurement eligibility, but reversing this decision in a subsequent solicitation.

facilities would cease operation and no policy action were taken, then it follows that policy action which prevents such facilities from ceasing operation could be deemed consistent with the concept of additionality. Because landfill gas to energy facilities and hydroelectric facilities have very low operating costs, this concept is more likely to apply to biomass facilities with fuel and other operating costs that may not adequately be covered by today's commodity market revenues.

2.3 Constraints

Numerous factors will constrain DEEP's ability to modify both the current RPS program and implement the approaches considered in this white paper. Table 2 summarizes the anticipated constraints.

Table 2: Policy Constraints

Constraint	Implications
Cost Effectiveness	The approach taken must meet the universal constraint of accomplishing the policy objectives cost-effectively.
Commodity Energy Market Conditions	At this time and for the foreseeable future, the energy market price is at a historical low. This impacts the feasibility of a Connecticut entity procuring the bundled energy and renewable attributes at a relatively attractive price.
Jurisdiction and Authority	Additional statutory authority may be required to implement some options to implement the contemplated construct. Further, some aspects of the wholesale energy market are under Federal jurisdiction (pursuant to the Federal Power Act), which might limit Connecticut authority to compel certain transactions.
Electricity Market Structure in Connecticut	CT has a competitive retail market structure and the jurisdictional electric distribution companies (EDCs) serve as providers of last resort to a shrinking proportion of retail load. As such, mandating a substantial quantity of long-term electricity contracts in a marketplace in which generation service is provided on a competitive basis presents challenges. 1) DEEP cannot compel competitive suppliers to purchase the contemplated supply, and competitive suppliers are typically insufficiently credit-worthy to make any such purchases financeable. 2) EDC generation service supply (Standard offer and Last Resort, or SO/LR): a. Is of unreliable and shrinking scale due to customer migration to competitive supply options. It is possible that during the course of the contemplated contracts, EDC purchases on behalf on standard service and SO/LR customers may be too small in scale to encompass the entire contemplated target. b. The stated objective and approved compliance plan for SO/LR is to track market prices (through a short-term ladder portfolio). The Public Utility Regulatory Authority (PURA) recently rejected arguments to incorporate long-term contracting within SO/LR supply. c. SO/LR supply is already accounted for under the recently approved compliance plan over the next few years. 3) Layering a pass-through of costs and benefits into non-bypassable wires charges is controversial, and can complicate or counteract hedges that end-use customers make for themselves through the competitive market. The implications of transaction structure are discussed further in Section 5.

Constraint	Implications
Renewable Energy (RPS) Market Structure in Connecticut and the Region	1) CT has established a Class I RPS which has already stimulated substantial private investment in response to, and reliance upon, the current rules. DEEP must consider how the potential new approach will impact and interact with the current CT RPS Class I market. Intervention in, and alteration of, the RPS eligibility and targets impacts the value of past investments, existing contractual commitments, and the willingness for investors to invest in the future without fear that further change will unpredictably cause investments to become uneconomic. Perceived risk impacts the cost of capital, which in turn significantly impacts the cost to ratepayers. Alternative policy design choices could augment, undermine, or be neutral to the investment climate. These implications are discussed further under Section 2.4, RPS Best Practices, and Section 2.5, Interaction with "Market" Class I Tier. 2) Tracking within the NEPOOL Generation Information System (GIS) will be required for verification of delivery, eligibility and unique claim (i.e. assuring that the same supply is not claimed or used more than once). This issue is discussed further in Section 9.
Political Viability	Proposed changes may engender resistance, or opposition, from impacted stakeholders, market participants and advocates, leading to risks that there will be protracted political or legal fights because of potential impacts. Examples include: 1) Interests/Advocates that support regional renewable energy (RE) development. 2) Interests/Advocates opposing transmission or new hydro development on environmental, land use, or other grounds. 3) Owners of Existing Class I-eligible generation, or investors in Class I generation under development but not yet operating, who have made substantial investments towards bringing such generation to market based in part on reliance on the current Class I rules. 4) Owners of existing generation of any kind in the region whose revenue prospects may be diminished by substantial new policy-driven, contracted supply.[3] 5) EDCs or competitive LSEs, to the extent that they are involved in the procurement transaction, and have already made forward commitments to meet future Class I obligations or are subject to other long-term RPS commitments stemming from other policy initiatives (Project 150, LRECs, ZRECs, etc.). 6) Transmission owners/developers, whose planned facilities may be impacted negatively by proposed changes. 7) Consumers, to the degree that proposed changes result in higher costs than the status quo or other alternatives.
Complexity	The more complex the approach, the greater the likelihood of implementation delays due to technical or practical considerations, statutory impediments, or legal challenges.
Avoiding Unintended Market impacts	1) Perceptions of market instability *during proposal and implementation phase* will be detrimental to investors, sellers and buyers. 2) Other goals of current the RPS could be undermined, including accelerating deployment of other renewable energy technology in CT at prices approaching grid parity.

[3] For example, this sector has been resistant to en exemption for renewables in the FCM market from the minimum offer price rule.

2.4 RPS Best Practices

RPS best practices include exercising caution with making changes, and making any changes with ample lead time (see **Text Box 1**). In the context of how Connecticut might design and implement a Contracted Class I Tier, the general principles and best practices of RPS design described above take on specific relevance. In particular:

- **Avoid Creating Political Uncertainty**: The presence of political risk and policy uncertainty is a destabilizing force for investors. Changes in the policies that originally attracted investors will devalue their investments. In order for the State to achieve all of its RPS policy goals, it must be seen as an attractive place to invest. Unfortunately, Connecticut has frequently modified the RPS.
- **Fairness**: Market participants have made and continue to make investments and financial commitments in response to the existing rules of the current RPS program. These might include development costs and investments, as well as transmission, purchase or retrofit investments. Connecticut must proceed with consideration of fairness to those making these commitments. These commitments are also linked to future participation in the ISO's forward capacity market (FCM). Generators have already made commitments with substantial financial consequences for FCAs for compliance years yet to occur, based on assumptions of project viability which included projections of REC revenues based on RPS rules at the time of the auctions. Major changes that take immediate effect signal investors that fairness is not a consideration. Changes in RPS program rules and targets should take effect sufficiently far in the future so as not to undermine those who have made investments.

Text Box 1: RPS Best Practices

A comprehensive study of RPS best practices (Wiser, Porter, & Grace, 2004) identifies RPS best practices relevant to the policy change being considered in Connecticut, including:

Cost Effective and Flexible: Implemented and administered in a straightforward, flexible, cost-effective, and not unduly burdensome manner. Ensure that:

- RPS administrators are allowed *limited* flexibility to accelerate or slow the RPS percentage increases (with sufficient notice) in the event of well-defined and extreme circumstances. In most cases, this allowance should be limited, clearly bounded, and exercised only with ample notice, in order to reduce regulatory risk to market participants.

Predictable. Provide market stability for all participants, reduce regulatory risk for generators and electricity suppliers, and improve the ability of renewable developers to obtain financeable long-term contracts. Ensure that:

- Eligibility rules (including technology, fuel, vintage, and location) are clear, well defined and stable, not subject to sudden change so market participants can assess eligibility *before* making significant financial commitments.
- Rules for the RPS are clearly defined, any material changes to the policy come with ample notice and lead-time, and changes occur only within narrowly defined parameters.

3 Interaction with "Market" Class I Tier

In considering how to tap low-cost large-scale hydro contracts[4] through establishing a Class I Contract Tier, the interaction of such contracts with the current market Class I Tier, and how, and to what degree, contracted supply may count towards targets, must be addressed. The implications of different policy design choices are impacted primarily by the scale of available large-scale hydro supply.

- Scale of available new hydroelectric supply compared to RPS market scale**.** As shown in Appendix A, the scale of incremental large-scale hydroelectric generation vastly exceeds what could be imported over either existing transmission ties to eastern Canada, or existing plus potential new transmission ties (such as the Northern Pass or the Northeast Energy Link[5], see Section 5.1). Furthermore, the quantity of new large-scale hydro supply that could be transmitted over either existing or new ties is equivalent to all of the New England region's incremental RPS demand for roughly a decade for all of the region's Class I RPS requirements combined.

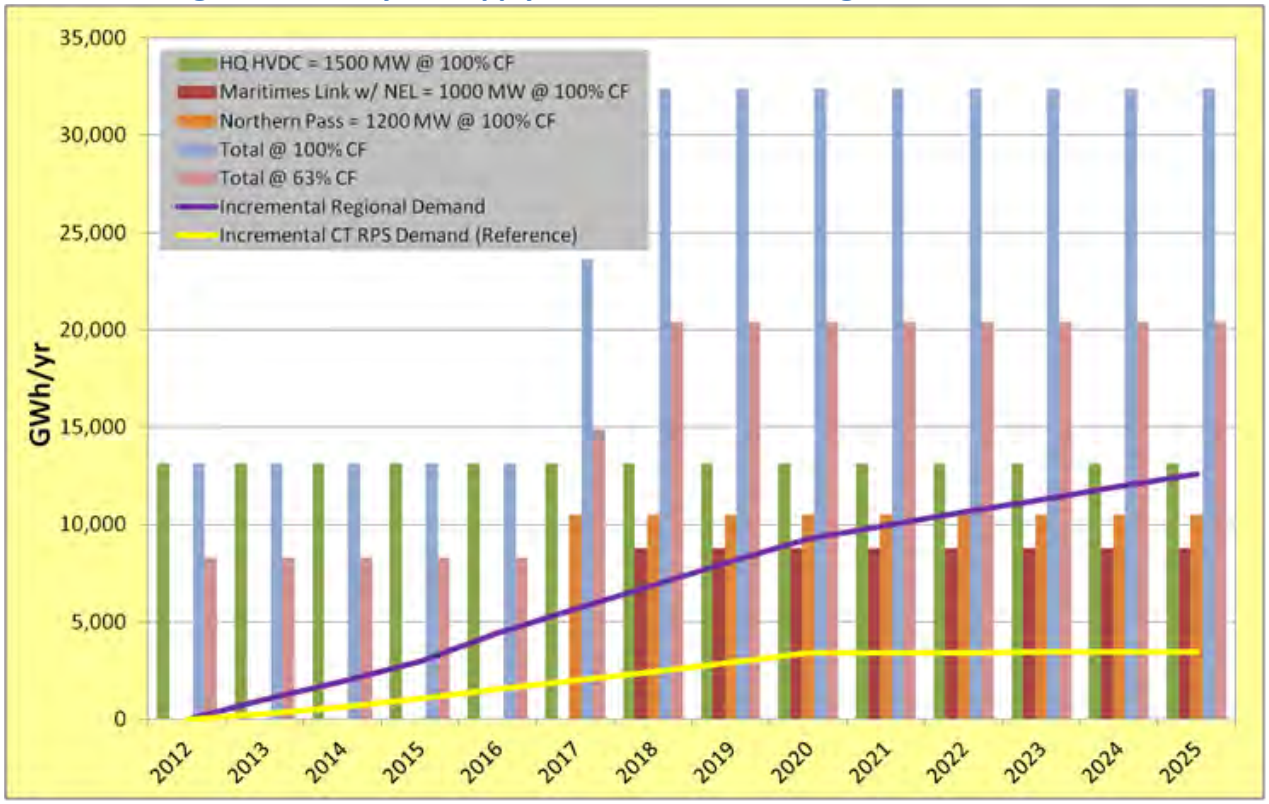
  Figure 1 illustrates an example of the quantities of potential incremental hydro supply that could be delivered over existing ties plus new transmission facilities[6] at both 100% capacity factor and 63% capacity factor. At 100% capacity factor, this represents the outer bound of large-scale hydro supply imports, representing an assumption of full utilization of each of these ties in all hours, including displacing the kind of transactions currently using the existing ties, and hydroelectric minimum production in all hours exceeding the transmission space on the ties. The 63% capacity factor figure represents the average capacity factor applied to incremental large-scale hydro in ISO New England planning studies, consistent with utilizing the ties to their maximum extend for unit-contingent transactions for the described MW of hydro capacity. It can also be considered a reasonable proxy for use of the ties to complement other users, rather than monopolizing use of the ties for the contemplated large-scale hydro transactions.

[4] The analyses in this white paper are based on the assumption that sufficiently long-term contracts, as described herein, can be secured by Connecticut without paying a material premium over *expected* long-term commodity market value. If a material premium is required to secure such contracts, the results, conclusions and recommendations made in this paper may differ.

[5] Northeast Energy Link is not a new intertie between New England and New Brunswick, but rather one of several transmission proposals to relieve transmission constraints between Northern Maine and southern New England. Addition of Northeast Energy Link or a competing proposal (such as the Green Line), would enable increased imports over the existing AC interties to the Canadian Maritimes.

[6] Northern Pass is assumed in this illustration to be the new transmission tie to Quebec, while the Northeast Energy Link (NEL) is assumed to be developed to relieve constraints within New England currently limiting the ability to utilize existing AC ties to the Canadian Maritimes to deliver substantial imports.

Figure 1: New Hydro Supply versus Incremental Regional RPS Demand



- Market power**.** Market power, simply put, is the ability for a firm to influence or manipulate price by influencing or exerting control over supply, demand or both. Market concentration – one supplier controlling a very large proportion of the market – is the primary means through which a supplier could exert market power. The level of regional, or Connecticut, Class I RPS market concentration of supply in the hands of a single entity[7] would violate thresholds for assessing acceptable market concentration by any standard means of calculation.[8] If a large-scale hydro supplier controlling an excessive share of eligible supply were allowed to compete without any restrictions in a market tier, the market would be highly susceptible to manipulation that could exclude competition and/or raise prices.

The scale of potential large-scale hydro supply compared to RPS demand, and the potential for the exercise of market power to manipulate the market, suggest that alternatives to simply adding new large-scale hydro to Class I eligibility be considered.

As discussed earlier, this white paper explores the potential mechanisms for effectuating, via competitive solicitation, long-term contract(s) under which new large-scale hydro resources would be

[7] In this case, suppliers like Hydro Quebec or NALCO whose incremental large-scale hydro development activities are described in Appendix A.
[8] For instance, the Herfindahl–Hirschman Index, or HHI, a commonly accepted measure of market concentration.

eligible. Here we consider the alternatives for how such a purchase would interact with the Market Class I Tier.

Issue: Structuring the Contracted Class I Tier in relation to the Market Class I Tier.

Options: Count the purchase towards renewable energy (RPS) goals by:

1. ***Expanding Class I eligibility to include large-scale hydro.*** The implications of this approach include:

   Advantages: May significantly reduce RPS compliance costs.

   Limitations: In short, including large-scale hydro within the CT Class I RPS would effectively overwhelm the Connecticut market. In addition, by displacing generation eligible in both CT and other New England RPS markets, this approach would create a ripple effect into other New England Class I RPS markets as well. This approach would fail to limit any renewable eligibility of large-scale hydro to the amount procured under the contemplated contracts. Due the vast quantities of potentially eligible large-scale hydro, expanding eligibility without limiting the quantity or substantially expanding targets (well beyond the level contemplated) would shift the actual and perceived supply-demand balance into an expectation of extreme surplus. The scale of the impact would make many of the advanced renewable development projects in the pipeline unfinanceable. It would also threaten to overfill the RPS targets so that EDCs required to purchase RECs under the variety of in-state renewable energy policies[9] might be unable to resell them (as required by PURA order) in a flooded market. This approach would violate RPS best practices described in Section 2.4**,** and push generation already developed in response to the Class I policy out of the market, potentially causing the shut-down of eligible renewables facilities, and deeply damaging the financial stability of generators that made substantial investments based on the current CT RPS. Doing such, would exacerbate expectations of political uncertainty. Finally, as discussed above, it would create substantial market power problems.

2. ***Creating a distinct Class I sub-tier for which large-scale hydro would be eligible (in addition to other Class I-eligible generation).***

   Advantages: Can accomplish the objectives outlined earlier without dramatically oversupplying the Class I market for Connecticut or creating a market power problem. Would reduce RPS costs to the extent that some portion of the Contracted Class I Tier *replaced* a portion of the Market Class I Tier (i.e. a portion of the current targets is shifted to Contracted Class I Tier).

   Limitations: Will limit large-scale hydro generation to the size of the sub-tier, so that any cost reduction to the Market Class I tier would be less than if unlimited.

3. ***Creating a separate RPS tier, or non-RPS tier (i.e. a greenhouse gas tier) outside of the current RPS policy.***

   Advantages: No impact on Class I market. Improves environment by displacing fossil generation.

   Limitations: No savings since it will not displace Class I or impact REC prices in Class I market.

[9] Such as project 150 or the ZREC or LREC programs.

Recommendation: Use option 2 or 3 to procure the sought-after supply outside of, and segregated from, the Class I *market* structure. A companion white paper developed by Sustainable Energy Advantage, entitled ***Connecticut Class I RPS Eligibility: Issues and Options*** describes projections of the existing and committed Connecticut Class I RPS–eligible supply that might be impacted by the proposed changes.

4 Eligibility for Contracted Class I RPS Tier

Eligibility criteria are key elements of RPS program design to ensure that program objectives are met and to provide clarity to the marketplace. Such criteria typically include the type of generating technology, the geographic location of the generators, the ability to deliver energy into the program's control area, and the generator vintage (i.e. resources brought online after the creation of the RPS or some other temporal milestone). In addition, eligibility may be determined by the capacity, environmental impact, or other operating or design characteristics of the facility. The creation of a new Contracted Class I Tier requires specifying the eligibility of resources that can meet the new Tier's targets.

Currently, the Class I RPS limits eligible hydroelectric resources to:

> *"…a run-of-the-river hydropower facility provided such facility has a generating capacity of not more than five megawatts, does not cause an appreciable change in the river flow, and began operation after July 1, 2003." (Conn. Gen. Stat. §16-1(a)(26))*

As noted in the discussion of objectives (and as further analyzed in Section 8.1), the Contracted Class I Tier is envisioned to be open to both resources currently eligible for the Market Class I Tier, and large-scale hydro resources not currently eligible. Below we describe some of the implications of setting various eligibility criteria for qualifying large-scale hydroelectric supply for a Contracted Class I Tier. It is beyond the scope of this white paper to discuss changes to eligibility of other resources that would compete in this new tier.

4.1 Geographic Eligibility

Under current RPS regulations in Connecticut, (Connecticut Public Utilities Regulatory Authority) and each of the other New England States with RPS requirements, for RECs from renewable generation imported from outside the New England control area to be RPS-eligible, the commodity must be delivered into ISO-NE from an *adjacent control area* (Hydro Quebec, the Maritimes Control Area, or NYISO). [10,11] These geographic eligibility requirements ensure that the attributes of the renewable

[10] Maine's geographic eligibility differs slightly because part of the state is treated as part of the Maritimes control area.
[11] This approach is referred to as *strict energy delivery with wholesale matching,* an approach that allows full unbundling of energy and attributes (RECs) within the sink market area, but attributes from outside the market must be bundled with

energy used to comply with an RPS target are not used or claimed elsewhere. In addition, they serve to ensure both a nexus to sales (credible claim that the source is part of retail supply) and that the imported supply would cause reasonably comparable system and environmental impacts to generation within the region (i.e. by virtue of its displacement of non-renewable generation, reduction of in-region emissions, etc). (Grace & Wiser, 2002) Renewable generation within the ISO-NE area can be tracked through the NEPOOL GIS, and as a result, the purchase of the RECs for RPS compliance and energy commodity can be separated. At present, the statutory eligibility footprint for the CT RPS includes RECs from generation located within or imported into ISO-NE, consistent with the rules of the NEPOOL GIS.

RPS geographic eligibility rules for New England RPS policies as effectuated within NEPOOL GIS rules were one of the most highly contested elements in creating the RPS and GIS operating rules. The current treatment of RPS-eligible renewable energy imports into New England was ultimately resolved in a way that balances the needs for integrity, competition, a level playing field, and regional consistency (enhancing standardization and liquidity rather than balkanized markets). Any proposals to alter the current geographic eligibility criteria must be understood within this context, as they will be seen by many as reopening a delicately balanced negotiated settlement.

Options for geographic eligibility for the Contracted Class I Tier include**:**

1. ***Current statutory footprint:***

   Advantages:
   - Ensures a nexus to retail sales, no double counting, displacement of fossil-fueled generation within ISO-NE.
   - Consistent with current treatment and underlying rationale.
   - Avoids reopening one of most controversial aspects of program and NEPOOL GIS design; and
   - Adequate supply is likely to be available without undertaking a change.

   Limitations: May provide less competitive options and competitive price pressure than Option 2.

2. ***Expanded footprint to include Newfoundland and Labrador***. This region is developing substantial large-scale hydroelectric generation targeting export markets, expected to come online as soon as 2017[12]. Pursuing this option would require changes to both the RPS statute and carefully limited changes to NEPOOL GIS rules for reasons elaborated below. It would also require the establishment of a compatible information system for Newfoundland and Labrador to ensure no double counting or double use of the claimed supply and associated benefits. The adjacent control area standard was adopted, in part, because of concerns over effectively tracking whether transactions from more remote control areas interconnected with yet other control areas were open to shell-games or 'green-washing' transactions. In this case, the Nalcor

electricity imports in order to create a REC, which can only be unbundled and sold separately from energy after the corresponding energy is imported . (Grace & Wiser, 2002)

[12] What is less clear is when transmission necessary to deliver this supply to New England would be completed. As discussed further in Appendix A, the compound contingencies of multiple transmission projects, coupled with the propensity for complex transmission system project timelines to slip, could delay availability of this supply beyond 2017.

system is effectively a dead-end system, only connected to another control area adjacent to NEPOOL. Rather than relaxing the adjacent control area standard, rules could be amended to treat Nalcor as part of the adjacent control area(s) through which it would transmit energy to NEPOOL since its electrical isolation prevents intermingling the energy with supply that could flow elsewhere. This approach is similar to the *dedicated extension eligibility* approach to geographic eligibility.[13]

Advantages: Would provide Connecticut with a greater range of potential sources resulting in increased competitive pressure and the potential for a better competitively-derived price.

Limitations: Changing the geographic eligibility footprint in the RPS rules and the GIS will be highly controversial and could cause unintended consequences unless implemented in a narrowly limited manner. Expanding geographic eligibility beyond the current adjacent control area standard could potentially bring in other Class I generating resources thereby disrupting the existing Class I market in Connecticut and others states.

Recommendation: Because competition is highly desirable, Option 2 is preferable (at least, once supply from this region becomes available for delivery to NEPOOOL). To effectuate Option 2, DEEP would commence discussions through NESCOE around opening NEPOOL GIS import rules to include Nalco resources under a narrow set of conditions, including establishment of a compatible GIS. Because NALCO is a dead-end system there would be no risk of inter-mingling generation from other ineligible control areas.

4.2 Vintage Eligibility

The date that a given renewable facility commences operation is its vintage. RPS programs can be designed to support new facilities, pre-existing (or legacy) facilities, or both. "Growth" RPS tiers limit eligibility to "new" facilities - those that begin operation after some specified date such as the date the RPS program became effective – and are designed to encourage and support the development of facilities built in response to the establishment of the RPS program. This eligibility criterion is tied directly to the objective of supporting additional or incremental generation (see Section 2.2 Additionality), and avoiding having RPS-based support (i.e. ratepayer money) directed to facilities that don't require additional RPS support to continue operating because:

- they were in existence prior to the program,
- had their initial investments fully paid for by regulated customers, and
- have sufficiently low operation, maintenance and capital replacement costs that they don't require additional RPS support to continue operation.

All other New England states' Class I Tiers are growth tiers, with increasing targets limited to new generation. In other New England states, existing renewable facilities are typically eligible in a separate Tier (which we refer to as "Maintenance" Tiers"). The objective of maintenance tiers is to prevent the attrition of legacy renewable energy facilities subjected to post-restructuring market forces, although usually via a lower level of support than that available for facilities that are eligible

[13] "Dedicated extension eligibility" is a mechanism to narrowly expand geographic strict delivered energy eligibility consistent with that approach's underlying philosophy. It requires generators to be either located within a defined market area or connected into that market area via a dedicated radial line without being intermingled with electricity not physically metered by that grid's administrators. This approach has been taken for the Texas RPS. (Grace & Wiser, 2002)

under the new category. Connecticut's Class I RPS is an exception as it has no vintage eligibility threshold *except* for the limit on hydroelectric that must have begun operation after July 1, 2003.

Issue: Vintage eligibility threshold for powerhouse commercial operation[14]

Options:

1. Only *new* large-scale hydroelectric[15] would be eligible.
   Advantages: Consistent with current CT hydro eligibility; Necessary to satisfy additionality; and as shown in Appendix A, the quantity of planned new hydro supply is more than sufficient to meet any reasonable target for a Connecticut Contracted Class I Tier.
   Limitations: Less supply available than Option 2.
2. No vintage threshold.
   Advantages: Broader base of supply from which to meet the target.
   Limitations: Likely to be highly controversial; Fails to satisfy additionality objective; Conflicts with rationale applied to limit hydro to new under current RPS statute; Unnecessary, as existing large-scale hydro is already competitive with other energy sources.

Recommendation: Adopt a vintage eligibility threshold. As noted in Appendix A, there is ample available supply. Setting a vintage threshold will support an additionality objective and avoid the criticism that would come with using legacy hydro to meet RPS targets or greenhouse gas reduction goals.

Issue: Establishing a Threshold Date

Options:

1. Commercial operation after October 1, 2011, the date of the passage of PA 11-80 when legislature instructed DEEP to perform this analysis.
   a. Advantages: linked to legislative action.
   b. Limitations: There may not be adequate eligible supply available in the near-term to fulfill targeted supply or create competition.
2. Commercial operation after July 1, 2003 (consistent with existing Class I RPS threshold for hydro).
   a. Advantages: Consistent with current CT hydro eligibility; there is adequate supply to meet targets under consideration.
   b. Limitations: n/a.
3. Commercial Operation after December 31, 1997 (consistent with Massachusetts and Rhode Island RPS).
   a. Advantages: Regional consistency; there is adequate supply to meet targets under consideration.
   b. Limitations: n/a.

[14] A corollary option that could be examined might consider the vintage of the dam or impoundment. For example, other state Class I hydro eligibility may limit incremental hydro to generation at existing dams or creating no new impoundments; the Low Impact Hydro Institute standard also limits new hydro top adding or increasing capacity at existing dams. However, imposing such a limitation would foreclose consideration of all substantial sources of additional hydroelectric supply, nearly all of which envision new impoundments, so is not considered further here.

[15] Consideration of altering the vintage eligibility for the current Market Class I Tier is beyond the scope of this paper.

4. Commercial Operation after August 1, 1998 (consistent with Low Impact Hydropower Institute definition of new hydropower facilities *as existing dams that added or increased power generation capacity after August of 1998*) (Low Impact Hydropower Institute (LIHI), 2011).
    a. Advantages: Consistency with LIHI standard; there is adequate supply to meet targets under consideration.
    b. Limitations: If other LIHI limitations are not applied (e.g. allowing existing dams), there is little rationale for applying the LIHI standard.

Recommendation: Of these options, there is no material distinction between the amount of supply available under options 1 or 2, relative to what is needed to meet the requirements under consideration. Option 2 meets to objectives, and more appropriate since it adopts the date threshold consistent with Connecticut's RPS formation, as opposed to the dates associated with neighboring states.

4.3 Facility Size and Characteristics

Hydroelectric facilities fall into two broad categories, storage (dammed) or run-of-river. For run–of-river, inflows roughly equal outflows; storage hydro can impound water and direct generation to times of higher need and value, and thus has greater value in energy markets as well as capacity and reliability value.

Hydroelectric generation is not free from environmental impacts. Impacts commonly cited include flooding river habitat, blocking fish passage, altering natural flow cycles, degrading water quality, inundating landscape, etc. Further, the inundation of landscape required by storage type hydro facilities contributes to GHG emissions because of the release of methane from the decaying plant material beneath the reservoir.[16] Run of river facilities do not involve creating storage reservoirs by inundating land and can be designed and operated in a way that has fewer environmental impacts and greater net GHG benefits per unit of production.

As a result, most RPS programs in the region, Connecticut included, place limitations on either size, physical or operating characteristics, and/or other impacts in determining hydroelectric eligibility as an acknowledgement of the environmental impacts of impoundment and storage. These limitations may be specific (run-of-river or no new impoundments, fish ladders, etc.), by capacity (i.e. less than some MW size threshold, as a proxy for lower or higher impact), or require a more nuanced threshold of lower impact (e.g. through LIHI certification or meeting certain requirements of licensing or natural resource agencies).

The current limitations in Connecticut and other states' RPS mandates reflect the fact that many stakeholders object to the creation of new storage dams because of their significant environmental impacts and strongly oppose any regulatory program that supports or incentivizes new dams. The

[16] A recent study commissioned by Conservation Law Foundation showed that the GHG emissions of new storage hydropower in the early years of operation are higher than emissions from combined cycle natural gas facilities. (Synapse Energy Economics, 2012).

Massachusetts and Pennsylvania RPS programs tie eligibility of hydro to whether a facility has received certification from the Low Impact Hydro Institute. LIHI established criteria for hydro facilities and issue certification according to LIHI criteria in the following areas: river flows, water quality, fish passage and protection, watershed protection, threatened and endangered species protection, cultural resource protection, recreation, and facilities recommended for removal (Low Impact Hydropower Institute (LIHI), 2011). Currently there is no program for certifying facilities outside of the U.S.

Possible eligibility standards to consider for large-scale hydro resources include imposing a capacity threshold, flow or impoundment limitations, or an environmental impact standard.

Issue: Capacity Threshold

Opening up the Contracted Class I Tier to large-scale hydro necessitates relaxing the 5 MW cap that currently applies to hydro in the Market Class I Tier. Caps are set at varying levels in other states' RPS programs in the region (e.g. 30 MW in MA and RI, 100 MW in ME) with the implicit objective of excluding the types of facilities this study is explicitly evaluating for the inclusion in a Contracted Class I Tier. These limitations are therefore clearly not applicable in the context of this paper.

Options:

1. ***No cap***.
   Advantages: Maximizes available supply and competition (including from large-scale wind).
   Limitations: Does not screen out the largest projects which (some would argue) could have the highest social and environmental impact.
2. ***MW cap at some larger amount***. In Appendix A, we quantify the available supply at different potential size cap levels. This analysis demonstrates that applying several potential cutoffs may not materially limit available supply relative to potential Contracted Class I Tier targets.
   Advantages: May screen out the highest impact projects (although size is a poor proxy for impact).
   Limitations: Limits available supply and competition (including from large-scale wind).

Recommendation: No cap (Option 1). Size is a poor proxy for impact, and a substantial limit would preclude participation by the very generation that is motivating this analysis.

Issue: Flow or Impoundment Limitation:

Options:

1. ***Impose a requirement limiting generation to facilities that do not create new impoundments***.
   Advantages: Lower environmental impact than hydro that does requires new impoundments.
   Limitation: Would defeat the purpose of establishing the Contracted Class I Tier by excluding the very resources that are driving the policy's consideration.
2. ***No limitation***.
   Advantages: Maximizes available supply and price competition.
   Limitation: Would allow generation with greater potential environmental impacts than small run-of-river or some other hydro such as LIHI certified.

Recommendation: No limitation on flow or impoundment since limitations of this sort would defeat the purpose of the proposed policy initiative by excluding the very resources that are driving the policy's consideration.

Issue: Greenhouse Gas Emissions:
One of the key drivers of the policy under consideration is the State's Global Warming Solutions Act.
Options:

1. ***No Standard.*** Any large-scale hydroelectric or other generation deemed Class I-eligible would be eligible for the Contracted Class I Tier.
   Advantages: Ease of administration.
   Limitation: Fails to consider how PPA purchases impact one of the key driving RPS objectives.
2. ***Impose a greenhouse gas monitoring/disclosure requirement.*** Under this approach, as part of its GHG tracking and reporting, DEEP would take into account and disclose the *net* GHG benefits associated with the contracted supply based on the best scientific studies of net benefits. While large-scale hydroelectric generation does not directly emit greenhouse gases, and therefore expanded production displaces greenhouse gas emissions from other sources, the flooding of land behind the dam to create a reservoir is understood to cause greenhouse gas release and alter greenhouse gas absorption. Therefore, monitoring and disclosing incremental impacts would involve comparison to an historic baseline.[17]
   Advantages: Accurately evaluating the realistic net contribution of large-scale hydro is key to honestly evaluating the contribution of the contemplated PPAs towards meeting greenhouse gas reduction goals.
   Limitation: The scientific data on such impacts are immature, and subject to refinement based on future research.
3. ***Impose a greenhouse gas impact threshold standard.*** This approach would require that all generation eligible for the Contracted Class I Tier PPA achieve net greenhouse gas emissions a low a specified threshold on a per MWh basis. Any generation exceeding the threshold would be ineligible.
   Advantages: Such an approach would assure a well understood progress associated with the contemplated PPAs towards meeting greenhouse gas reduction goals.
   Limitation: At present, we are not aware of a rigorous and generally accepted scientific methodology available at present that could be used to measure and evaluate the generating sources under consideration for the Contracted Class I Tier.

Recommendation: At a minimum, it is important to understand and account for the *net* greenhouse gas emissions associated with the generation supplying the Contracted Class I Tier. However, the precise role of the Contracted Class I as a contributor to meeting greenhouse gas

[17] The New England region has historically imported substantial amounts of system power from Hydro-Québec over existing HVDC transmission facilities. A PPA designated as large-scale hydroelectric supply of similar volume two such historic imports will not create incremental GHG benefit due to displacement of fossil generation in New England. Those benefits are already accounted for by NEPOOL directly or indirectly. Only incremental imports from incremental supply will reduce greenhouse gas emissions from New England fossil fuel supply. Dynamics of this sort should be taken into account in determining the actual greenhouse gas impact of Contracted Class I Tier PPAs.

goals has yet to be fully established. Perhaps more importantly, as noted above, the science is an inadequately advanced to apply an estimation of net greenhouse gas impacts as eligibility standard that could be used to include or exclude large-scale hydro supply, or is the basis for imposing penalties. Therefore, Option 2 – establishing monitoring and disclosure requirements – will allow Connecticut to commence on a path toward establishing a standard consistent with Option 3, allowing time to build technical record that is grounded indefensible for use as a standard in the future.

5 Contracted Class I Tier Quantities and Timing

The Contracted Class I Tier can be represented as a wedge on a plot of quantity versus time. The shape of this wedge is influenced by

- the ultimate target for the sum of the Market Class I Tier plus Contracted Class I Tier (the height) (Combined Class I Target),
- the degree to which the current Market Class I Tier target schedule is maintained or modified,
- the year in which the Contracted Class I Tier commences, and
- the rate at which the Contracted Class I Tier grows.

5.1 Constraints on Maximum Size of Contracted Class I Tier

The potential scale of a Contracted Class I Tier is limited by four factors: the available supply of eligible large-scale hydro or other eligible supply; the practical physical and contractual limitations on the ability to deliver that supply to load (e.g. the available transfer capacity over existing or new transmission ties into ISO New England and within New England); the source's impact on the ISO New England system's capacity reserve requirements, and the transactional outlet for the supply.

- ***Hydro Supply:*** The Appendix A analysis of available new hydroelectric supply in Eastern Canada demonstrates that Hydro Quebec alone has more than enough potential supply to fill up available space on existing or proposed new transmission ties to bring that supply to New England load. Therefore the binding constraint is transmission's available transfer capacity.
- ***Other Eligible Supply:*** As discussed herein, the proposed Contracted Class I Tier would be solicited through a competitive process open to other Class I RPS-eligible technologies. Onshore wind would likely be the other dominant supply source. Previously identified supply is potentially ample[18], although much of this supply is dependent on siting and permitting of both the wind projects and major new transmission in Northern New England. For purposes of this analysis we assume that the Contracted Tier will have access to such other eligible supply sources so long as a Contracted Tier solicitation is timed to take the development process into account and structured to provide the means to fund needed transmission capacity.
- ***Transmission Availability:***
    - <u>Access to existing ties</u>:

[18] As pointed out in the CT IRP (Appendix D), the response to NESCOE's 2011 RFI included over 50 renewable generation projects have responded, totaling ~ 4,700 MW of new generation capacity. Onshore wind in Maine represented more than 50% of this capacity.

- **Existing HVDC tie to Quebec**: This tie is capable of exporting between 1500 and 1800 MW to New England (with 1200 MW capacity from New England to Quebec). The line is owned by National Grid, but the approximately 30 utilities that signed a support agreement are the rights-holders, each controlling a contractually-determined percentage of the transfer rights. These rights are either transferred to other parties (for a fee) over varying durations, or posted on OASIS (the transmission reservation online platform) as available to others to use short-term. In effect, the rights are currently spoken for on a longer-term basis. HQUS is the majority rights holder, while some other entities also control material shares. According to a HQUS executive, at present, HQUS holds over 1000 MW of transmission service rights which could be utilized for the contemplated transactions. Of note, these rights include a variety of terms, representing a portfolio of transactions, some with renewal rights and others without.[19] As a result, in the near-term this pathway appears relatively unconstrained; however we cannot assume that a transaction of 1000 MW scale could be entered into for a 20-30 year period using existing ties. While such a scenario is possible, HQUS does not control firm rights in perpetuity.
- **Highgate Converter (Quebec)**: Another tie to Quebec, the Highgate converter, can carry about 218 MW (ISO New England, 2011). The capacity is already spoken for as the pathway for recent system power contracts between Hydro Quebec and the Vermont utilities so this tie is not relevant to this analysis.
- **Maritimes**: The existing MECO and NRI ties, with a combined total transfer capacity of 1000 MW (ISO New England, 2011), to the Canadian Maritimes are historically used for a variety of transactions, but are **expected** to have a moderate amount of incremental transfer capacity into New England. Their increased usage is more constrained by north-south transmission constraints within New England, so increased use of these ties is dependent on additional in-region transmission investment.
- **New York ties**: Although the over 1900 MW[20] total import transfer capacity from various ties from New York are heavily used, there is substantial space that could be available. However, due to limited potential supply for the Contracted Class I Tier from the NYISO control area, the availability of space on these ties is not expected to be a material consideration.

- <u>Potential New ties</u>:
  - **Northern Pass:** This proposed participant-funded 1200 MW HVDC connection, planned by Northeast Utilities and proposed to be contracted to HQUS, is well into

[19] Phone interview (Molodetz, 2012)
[20] (ISO New England, 2011)

the process of acquiring the land and rights of way needed for development and, if completed, would be available no earlier than 2017. (The Northern Pass)

- **Potential new tie between New York and Vermont:** From time to time there have been discussions about developing a new or expanded AC tie between Vermont and upstate New York to access bottled-in wind power. However, for the purposes of this study we have not included this pathway.

- Facilities to integrate in-region supply: A variety of studies have been undertaken by ISO-NE, NESCOE, and utility and non-utility proponents of alternative transmission solutions such as the Green Line and the Northeast Energy Link. Additional studies are underway to explore the build-out of network transmission. The scale and availability of such facilities to access regional onshore wind is assumed to be primarily constrained by the ability to pay for them. Addressing this financial challenge has been the focus of efforts such as the NESCOE Regional procurement. Tracking these developments will be important to determining the availability of wind and potentially other resources to compete with large-scale hydro resources.
    - **Northeast Energy Link (NEL):** One example is the Northeast Energy Link. This 1100 MW HVDC pathway is proposed to deliver renewable energy from northern and eastern Maine and eastern Canada into southern New England. We anticipate that a material component of the line's capacity would be used for generation (primarily wind) within New England, but it could also be available to support transfer of Canadian Hydro. While the project proponents (National Grid, Emera and Bangor Hydro) represent on the project web site[21] that the project would be completed at the end of 2016, for purposes of this analysis we assume that it is energized in 2018.

Table 3 summarizes the potential upper bound on available supply as constrained by different potential transmission futures.

[21] http://www.northeastenergylink.com/

Table 3: Potential Eastern Canada Supply and Transmission Constraints

	2025		
	GWh	MW	aMW[22]
Potential Generation Supply	47,925	8,684	5,471
Available Through Current HVDC Tie[23]	8,760	1,000	1,000
Addition of Northern Pass (2017)	10,512	1,200	1,200
Addition of Northeast Energy Link (2018)[24]	9,636	1,100	1,100
Max Total Through All Ties	28,908	3,300	3,300

- ***Reliability impact:*** Large single supply sources (either generation or transmission access to generation) create risk to electric system reliability and trigger the need to address contingencies. The loss of load probability from small generators is negligible due to system diversification. However, loss of large supply sources dependent on a single factor – a unit or line outage – can have a material effect on the region's reserve requirements. The most significant material impacts derive from the largest first and second contingency, with each successively smaller contingency having a progressively smaller impact on the amount of capacity and operating reserves maintained throughout the ISO New England control area. The largest contingencies in the New England System are the HVDC line to Quebec and the largest nuclear plant, Millstone. These sources fall within the 1000 – 1500 MW range, which should be thought of as the upper range for any Contracted Class I Tier contract with a unit or transmission line contingency. So long as the scale of a single supply source or line is less than this range, there would not be material negative impacts on system reliability in the ISO-NE region.

Conclusion: Connecticut's entire RPS-eligible load in 2011 was approximately 29,700 GWh. In the long-term, available transmission capacity is unlikely to be a constraint on the scale of the transaction *unless other states pursue similar paths.* Reliability issues may serve as a practical upper bound, suggesting a transaction should not exceed the 1000 – 1500 MW range. In the near-term, the available contractual rights on the HVDC line represent the upper bound; even if HQUS did not in the long-run control the approximately 1000 MW of transfer rights it now controls, additional transmission lines may be able to make up for any loss of such rights by 2018 if new projects, such as Northern Pass, move forward.

[22] aMW is a useful benchmark for assessing energy equivalence, and represents the MW which if producing at 100% capacity factor would yield the equivalent energy. One can readily translate this figure into an equivalent nameplate MW for a particular technology by dividing by the annual capacity factor; for instance, the approximate MW of wind power would be roughly 3 times the aMW (aMW/.33 at a 33% c.f.).

[23] This assumes current level of rights available to HQUS continue to be contractually controlled in 2025.

[24] This assumes none of this line taken up by in-region wind; since the line is planned in part by Emera, who is a partner to the Northeast Wind joint venture with First Wind, this assumption is probably unrealistic.

Other states – Massachusetts, Rhode Island, Maine and New Hampshire - have all discussed or explored large-scale hydro contracts, and Vermont has already entered into one with Hydro Quebec. It may not be reasonable to assume Connecticut could, or would want to, secure the full available transmission capacity under any of these scenarios. For comparison, Table 4 shows the data in Table 3, reduced to 25%, which represents Connecticut's approximate share of regional RPS-eligible load.[25] If this represents Connecticut's pro-rata 'fair share' of the facilities, it suggests near-term limits of approximately 250 MW over existing ties, and ultimately something in the range of 825 MW. While these reduced levels do not represent hard constraints, they should be considered in designing policy to account for possible actions of other states, unless Connecticut moves independently.

Table 4: Potential Eastern Canada Supply and Transmission Constraints, CT Pro Rata 25% Share

	2025		
	GWh	MW	aMW
Potential Generation Supply	11,981	2,171	1,368
Available Through Current HVDC Tie	2,190	250	250
Addition of Northern Pass (2017)	2,628	300	300
Addition of Northeast Energy Link (2018)	2,409	275	275
Total Through All Ties	7,277	825	825

In considering which transaction structure approaches are feasible and desirable, the scale of potential PPA outlets can be compared against the potential Contracted Class I Tier scale. In 2012, the total RPS obligated load at wholesale is equal to approximately 30,600 GWh per year, or about 3500 aMW.[26] Approximately 30% of Connecticut's load is currently served under Standard Offer and Last Resort Service. If use of Contracted Class I Tier energy to supply EDC purchases of Standard Offer/Last Resort (SO/LR) service is deemed an appropriate disposition for such purchases, increasing customer migration to competitive supply may become a limiting factor.

5.2 Combined Target in 2025

To put these quantities in context, we next consider alternatives for combined Contracted and Market Class I Tier targets as well as the individual target for the Market Class I Tier and the Contracted Class I Tier in order to arrive at optimal targets for both. Table 5 shows a variety of potential combinations. We consider the status quo for Class I, i.e. 20% by 2020, with the Contracted Class I Tier carved out of a 20% combined total. As can be seen from the analyses in Section 5.4 and Appendix B, any case in which a material Contracted Class I Tier might be considered would reduce the Market Class I Tier targets from their current level, unless the combined Contracted and Market Class I Tier targets were also increased. Therefore, we have also considered a combined target greater than the current 20% Class I Market RPS reaching 25% by 2025, or (in Appendix B) higher.

[25] This figure is calculated counting Vermont load, as Vermont utilities are subject to renewable energy targets.
[26] 2012 NEPOOL CELT Report adjusted by SEA analysis of RPS obligated load.

As can be seen in Table 5, if the Contracted Class I Tier target represented 5% of retail load (or one quarter of the 2020 Class I target of 20%), it would correspond to approximately 180 average MW (aMW)[27], a figure that is not very large compared to the available supply. If supply for a Contracted Class I Tier is truly available without a premium, there may be merit to considering a larger commitment. As shown in Section 5.3 below, there is not much room to reduce Market Class I targets without displacing existing and committed Class I supply, including projected production from in-state Connecticut sources driven by policies already adopted by the State. Therefore, an increased RPS commitment that would correspond to an increase in the Combined (Market and Contracted) Class I targets beyond 2020 is also considered.

For comparison with today's 20% by 2020 RPS Class I benchmark, Table 5 shows the scale of energy and average MW associated with Contracted Class I Tier target levels of 5% through 30% of load. Comparing the projected average MW in each of the cases identified, we conclude that none of these options exceed the limits of what is potentially available.

Table 5: Options for 2025 Market and Contracted Class I Targets

Contracted Class I Tier % of load in 2025	Projected GWh equivalent[28]	Projected Average MW Equivalent (aMW)
5%	1,573	180
10%	3,146	359
20%	6,291	718
25%	7,864	898
30%	9,437	1,077

5.3 Timing and Ramp-up of Contracted Class I Tier

Constraints on the scale and timing of a hydro-eligible Contracted Class I Tier are influenced by a range of factors. We discuss the role and impact of each constraint as follows:

- ***The amount of eligible supply for the Contracted Class I Tier available over time*.** These factors are discussed in Section 5.1.
- ***Investments in development of, or purchase of, Class I renewables***. Investors have already made substantial investments in Class I resources, and are also making future delivery commitments which, under certain scenarios discussed in this paper, may no longer be

[27] aMW is a useful benchmark for assessing energy equivalence, and represents the MW which if producing at 100% capacity factor would yield the equivalent energy. One can readily translate this figure into an equivalent nameplate MW for a particular technology by dividing by the annual capacity factor; for instance, the approximate MW of wind power would be roughly 3 times the aMW (aMW/.33 at a 33% c.f.).

[28] Based on extrapolated NEPOOL 2012 Capacity, Energy, Load and Transmission (CELT) forecast. Base case CELT RPS-obligated load in 2025 is approximately 31,456 GWh, calculated by extrapolating the 2021 Connecticut base case load by the forecasted CT compound average annual growth rate, and excluding the approximately 6.5% of load exempt from the RPS.

economic. While policymakers will always reserve the right to change direction, the current and past RPS rules represent an implicit representation of policy to those already committed. The risk of change in law or regulation is a substantial and unhedgeable risk for project investors. Attracting private investment to meet the policy goals of a state becomes increasingly difficult if a state's policy changes are perceived to unfairly treat past investors relying on the state's policies.

- ***Current firm commitments of Class I supply in Forward Capacity Auctions.*** Power plants currently participating, or under development to participate, in the Connecticut Class I RPS market currently also participate in the ISO-NE Forward Capacity Market (FCM) through its Forward Capacity Auctions (FCAs). As noted in Section 2.4, generators have already made commitments to deliver based on prior FCAs for compliance years yet to occur. These commitments are based on projections of the viability of a project's cash flow including projections of REC revenues consistent with RPS rules at the time of those auctions. RPS best practices, and principles of fairness, discourage implementing changes that would penalize those who made such commitments without sufficient lead time. The last FCA (FCA6), held in May 2012, created obligations starting in commitment period 2015-16 (starting summer 2015), while in FCA7, resources prequalify and make firm commitments by April 2 for a May 2013 auction, corresponding to a commitment period of 2016-17. Such generators face a major financial exposure for not delivering once committed, and new generators risk loss of financial assurance. Bidders' commitments have already been made, or will shortly be made, for delivery for new resources for up to 5 years from the start of the commitment period, and for existing resources for 1 year from start of the first commitment period. As a result, existing commitments, relying on current RPS rules, may have already been made from 2016 through 2020, thereby suggesting caution in reducing any of these percentages without several years of lead time.
- ***Supply from current Market Class I supply already committed, and already adopted in-state policies.*** Consistent with the discussion in the prior two bullets, DEEP should consider the impact on already-committed Market Class I generation in determining whether, when and how much to allow a portion of those targets to be met through the Contracted Class I Tier. In particular:
    - While there is a modest shortage expected for compliance year 2012, the CT Class I supply was roughly equal to demand in 2011, suggesting that supply equivalent to about 8% of load had already been brought online. This quantity continues to increase, but in 2012 and perhaps 2013, not quite at the pace of demand. This supply includes generation from around the region as well as within Connecticut, including capacity brought online through various past CT solar and fuel cell programs.
    - A substantial additional quantity of Connecticut-based, policy-driven Class I supply will come online within the next few years, driven by either Project 150 or the suite of CT in-state renewables policies driven by Public Act 11-80 (together, the **"Existing In-State Programs"**).[29] Together, we project these sources will bring an additional 505 MW nameplate Class I capacity online, corresponding to ~ 165 aMW, approximately 4.3% of

[29] In addition to Project 150, the Public Act 11-80 programs include the LREC, ZREC, residential solar, anaerobic digester and Section 127 programs.

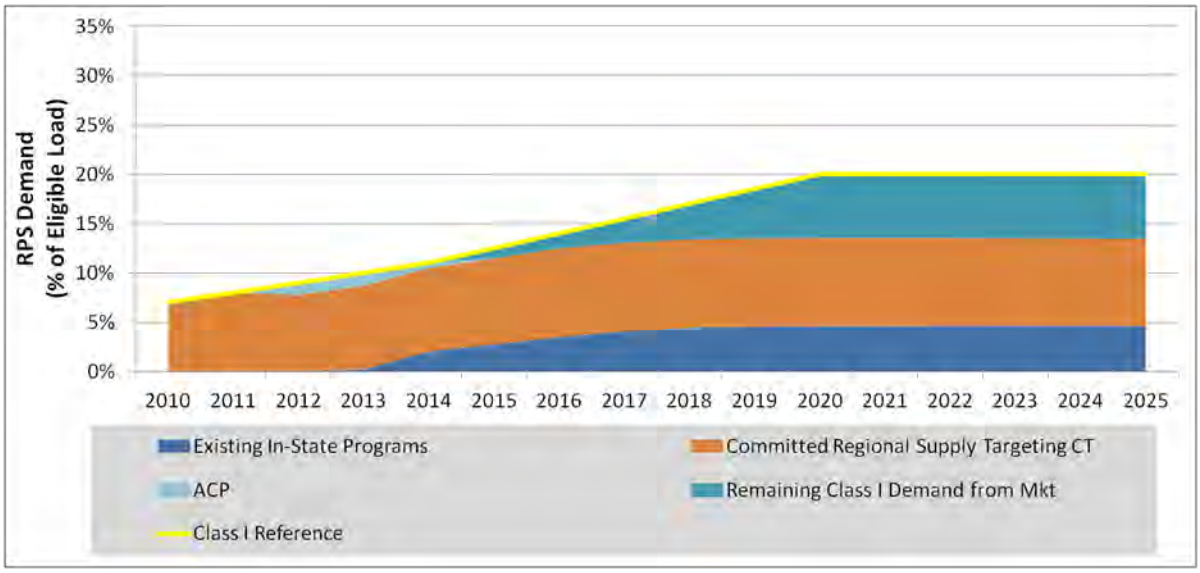
total RPS-obligated load, and representing almost 4 years worth of incremental Class I RPS demand.

Figure 2 depicts the current Connecticut Class I demand (the line) compared to different categories of supply:

- Orange Layer = supply either already operating, or committed, that is expected to be directed to meeting the Connecticut Class I RPS market;
- Dark Blue layer = the incremental supply to be brought online by the existing In-State Programs;
- Light Blue layer = projected near-term shortfall before additional supply resources are available, to be met by Alternative Compliance Payments (ACP).
- Turquoise layer = Remaining Class I Demand to be met from additional market resources not yet operating or under construction.

A shift of any portion of the targets (demand) from the current (market) Class I RPS to distinct Contracted Class I contracts will displace some portion of these supply sources. The impacts of a modest shift of RPS target percentages from the Market Class I Tier demand to the Contracted Class I Tier sufficient to only displace the area labeled as "remaining Class I demand from market" will be to shrink the market for regional Class I supply, while reducing ratepayer compliance costs by substituting the cost of Contacted Class I contracts (at little or no premium) for Class I REC payments. Such a shift would also moderate or eliminate customer exposure to future shortage. The impact of a larger shift, greater in magnitude than the turquoise layer representing incremental market supply, is more disruptive. While it could reduce ratepayer compliance cost further, it would do so by not only displacing all market opportunities for the new supply in the development pipeline, but also by effectively displacing operating or committed supply from the marketplace. As some of this supply is ineligible for other states' Class I RPS policies and may not be viable without REC revenue, some of this displaced supply could shut down. Such a change would be viewed, by the effected generators, as a move more akin to repealing the RPS than one meant to contain future costs.

Figure 2: Projected Share of Current CT Class I Targets Met by Committed Supply and Existing In-State Programs.



Text Box 2: SEA Updates to IRP Forecasts of RPS Supply and Demand

Appendix D of the IRP (Fig. 9, Base Case) shows adequate supply to meet regional aggregate RPS demand through 2017, and a potential gap between supply and demand starting in 2018 and continuing thereafter (Connecticut Department of Energy & Environmental Protection, 2012). SEA's December 2012 modeling yields results which differ somewhat from the IRP analysis and its conclusions due to a number of factors, including new information as well as methodological differences incorporating market dynamics not reflected in the IRP. The most important issues addressed in SEA's analysis that are not captured in the IRP include:

- In 2012, New Hampshire reduced its Class I target trajectory and carved out a portion of the remaining target for a renewable 'useful thermal energy' sub-tier, effectively shrinking RPS electricity targets.
- The IRP did not reflect the impact of load-serving entities banking excess compliance to apply against shortfalls in later years, a practice that is allowed in each New England state with an RPS. The IRP shows surplus for several years before 2017, but does not show the banking and later withdrawal of those banked surpluses, which in SEA's analysis may push the timing of a potential gap up to several years later.
- The IRP models the region as if it were a single market.[30] SEA's model reflects a state-by-state supply and demand balance. Due to different state eligibility requirements, the state-by-state supply-demand balance will differ from the aggregate regional picture, often in material ways. For example, CT's eligibility thresholds are more lax than some other states, Massachusetts has recently adopted more restrictive eligibility criteria, and states like Maine may have substantial surplus qualifying renewable resources not eligible elsewhere. In general, at times, Connecticut may be expected to have adequate supply when other states may not, while a state such as Maine may have surplus while other states are in shortage. For these reasons, a Connecticut-specific depiction is the correct analysis to use for assessing supply adequacy for the state.
- Since the IRP was completed, Massachusetts passed legislation in 2012 which establishes substantial new long-term contract solicitation requirements for utilities representing 4% of Massachusetts' total RPS-obligated load over the period 2013-2016. In addition, Rhode Island has statutory contracting requirements mandating nearly an additional 44 aMW of supply. The IRP does not reflect the impact of either of these states' statutory commitments, which impact not only those states but the entire regional supply-demand balance due to overlapping eligibility.
- SEA's analysis is based on more extensive data about the project development pipeline than the IRP. While there are many similarities with the data sources used to project RPS-eligible supply in the IRP, SEA's analysis uses a deeper and more thorough assessment of the renewable energy development pipeline, including reliance on a substantial volume of data not yet visible in public sources regarding renewable projects that was shared with SEA under conditions of confidentiality, as to the specifics, with data only to be disclosed in highly aggregated form. In contrast, after a certain point in the future, the IRP simply assumes a uniform 150 MW of wind added in each year of the analysis.
- SEA's analysis of the expected supply from Connecticut's in-state policies (such as the ZREC and LREC programs) is somewhat larger than that used in the IRP, due to more recent information reflecting actual bid results that were below price caps and more aggressive CEFIA solar goals.

[30] While the Class I Renewables analysis contained in this report treats New England as a single market, Connecticut's RPS has some unique eligibility characteristics that may create some disparities between Connecticut and other New England states. A subset of Class I RECs is only eligible in Connecticut. (IRP p. D-2)

- ***Anticipated time of need to avoid ACP.*** One consequence of the use of a Contracted Class I Tier to contribute to meeting the combined Class I targets is that it ensures that there is no substantial shortfall in meeting RPS targets, and therefore little or no exposure to ACP payments. The 2012 IRP found a potential exposure to ACP payments after 2017, creating an impetus for policymaker discussion of RPS changes to reduce or eliminate exposure to ACP payments (Connecticut Department of Energy & Environmental Protection, 2012). SEA has conducted an analysis of supply and demand which updates and refines that IRP analysis. Key differences between SEA's analysis and the IRP forecast are summarized in Text Box 2.

  Before presenting the results of SEA's analysis of Connecticut Class I demand, it is also useful to look at the implications of a gap between supply and demand projections from the IRP, and the associated conclusions, through a different lens. In either analysis, any gap shown between supply and demand does not mean that there *will* be a shortage, but rather that without additional supply beyond the current development pipeline, there *might* be a shortage. Development lead times for renewable projects are generally less than 4-5 years. As a result, there is ample time for additional renewables to be brought into the development pipeline to address a potential shortfall beyond that time frame.

  SEA's analysis summarized in Figure 3 indicates that under a **low supply reference case**, a *potential* gap that would require additional supply not currently counted in the development pipeline would not appear until 2019. Figure 4 illustrates the same scenario, but under a high supply outlook. The **high supply reference case** does not anticipate a supply gap until 2022, after which demand will need to be met with additional supply from the regional supply curve, or with ACP.

Figure 3: Connecticut Class I RPS Supply-Demand Balance, Low Supply Reference Case[31] (Sustainable Energy Advantage, December 2012).

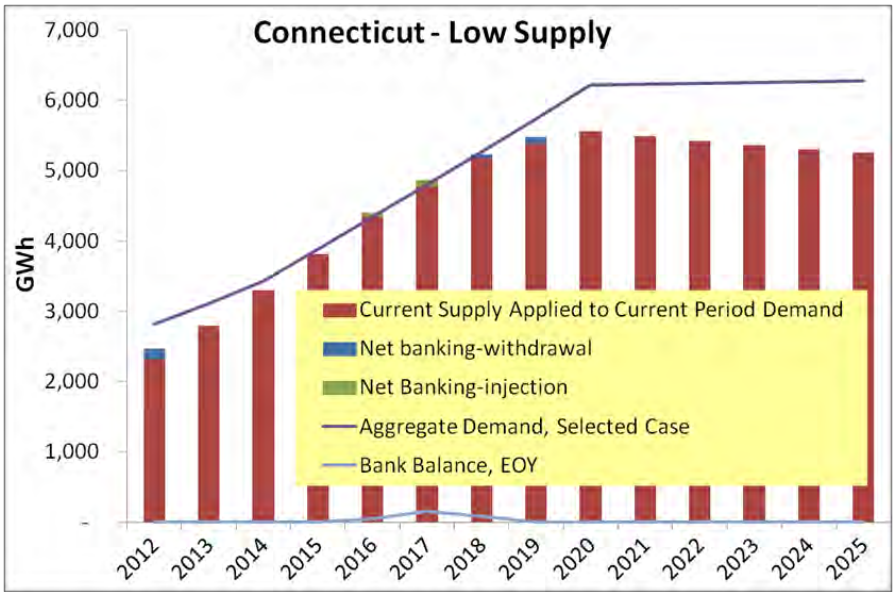
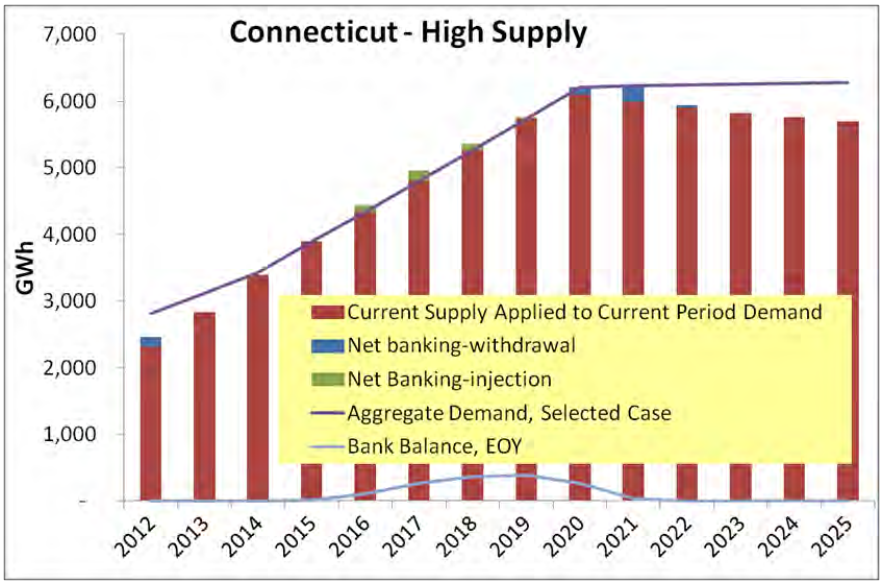


Figure 4: Connecticut Class I RPS Supply-Demand Balance, High Supply Reference Case[32] (Sustainable Energy Advantage, December 2012).



[31] The Low Supply Reference case is assumed to be PPA-limited (i.e. assumed that all current statutory PPA policies are fulfilled), rather than development pipeline-limited (i.e. assumed that supply quantities are limited by the current development pipeline (as derated for probability of success). The Low Supply case includes, among other assumptions, that there is no Rhode Island Federal offshore wind PPA, and that no new network transmission is built in Northern New England to access additional planned supply.

[32] The High Supply Reference case is assumed to be PPA-limited (i.e. assumed that all current statutory PPA policies are fulfilled), rather than development pipeline-limited (i.e. assumed that supply quantities are limited by the current probability-derated development pipeline. The High Supply case includes, among other assumptions, that Rhode Island Federal approves a 450 MW offshore wind PPA, and that new network transmission is built in Northern New England to access additional planned supply.

Both of these cases make the same assumptions regarding forward-looking policy initiatives. As a conservative approach, policies that are not currently enacted were removed from the reference cases and tested only as sensitivities to the final model. Thus, additional in-state incentive programs (referred to here as LREC/ZREC-II) and Connecticut participation in a large-scale regional procurement (i.e. the NESCOE regional procurement effort) are both excluded from the reference case supply forecast.

5.4 Alternative Contracted Class I Target Scenarios

Several scenarios were developed for potential Market Class I Tier and Contracted Class I Tier targets, the size and shape (timing and ramp-up) of the Contracted Class I Tier, and potential use of additional policies (e.g. LREC/ZREC-II and Connecticut participation in NESCOE regional renewable energy long-term contract procurement).[33] Originally, nine preliminary alternative scenarios were developed in order to assess and compare a wide range of potential policy changes. Each of these is presented in Appendix B. In these preliminary scenarios, the combined Class I target in 2025 ranged from 20% to 40%, and Contracted Tier options ranged from 5% to 20%.

After review and discussion of these preliminary scenarios with DEEP, these options were pared down, refined and combined to create four specific final target scenarios for analysis. An additional scenario was also developed to explore the role of conditional flexibility in altering targets based on the behavior and expectations of the market. These scenarios, presented in detail below, were designed and selected to demonstrate the major distinctions deemed most important from the preliminary analysis, after eliminating scenarios representing extreme curtailment of for expansion to RPS targets. Among the refined group presented in this section, the combined Class I target in 2025 ranges from 20% to 30%, and Contracted Tier options range from 5% to 10%. Assumptions relating to additional in-state or regional policies were held constant across all cases to allow for an equal comparison of the cost impacts of the Contracted Class I Tier alternatives. In a separate compliance cost analysis, fulfilling the remaining Class I RPS demand, if any, was explored under a range of different options.

Table 6 below provides a high-level overview of the Market and Contracted Tier Class I RPS targets across each scenario, while Figure 5 through Figure 8 illustrate each in graphical form. In the subsequent Section 5.5, an example of applying a conditional flexibility mechanism in response to market conditions is provided.

[33] The projected ratepayer policy compliance costs associated with each policy and market design scenario were subsequently evaluated through a compliance cost analysis, the results of which are not addressed in this paper.

Table 6: Final Contracted Class I Tier Scenarios Examined

Case	Combined Targets (Market and Contracted Tier)			Market Class I Tier			Contracted (Hydro Eligible) Tier		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
Reference	12.5%	20%	20%	12.5%	20%	20%	0%	0%	0%
Scenario 1 (20x20 w/ 5% Contracted Tier)	14.6%	20%	20%	11.6%	15%	15%	3%	5%	5%
Scenario 2 (20x20 w/ 10% Contracted)	16%	20%	20%	10%	10%	10%	6%	10%	10%
Scenario 3 (25x25 w/ 7.5% Contracted)	14.6%	20%	25%	11.6%	15%	17.5%	3%	5%	7.5%
Scenario 4 (30x25 w/ 10% Contracted)	17.8%	25.5%	30%	12.3%	17.5%	20%	5.5%	8%	10%

Figure 5. Scenario 1

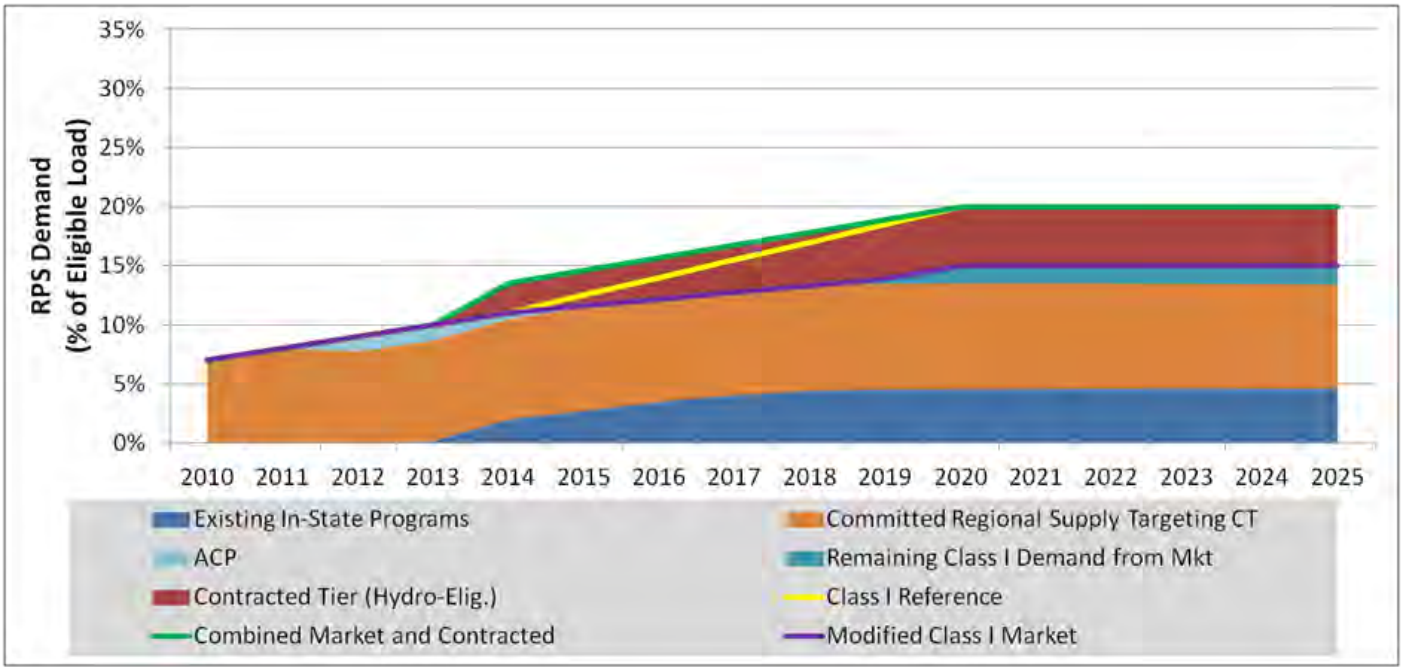
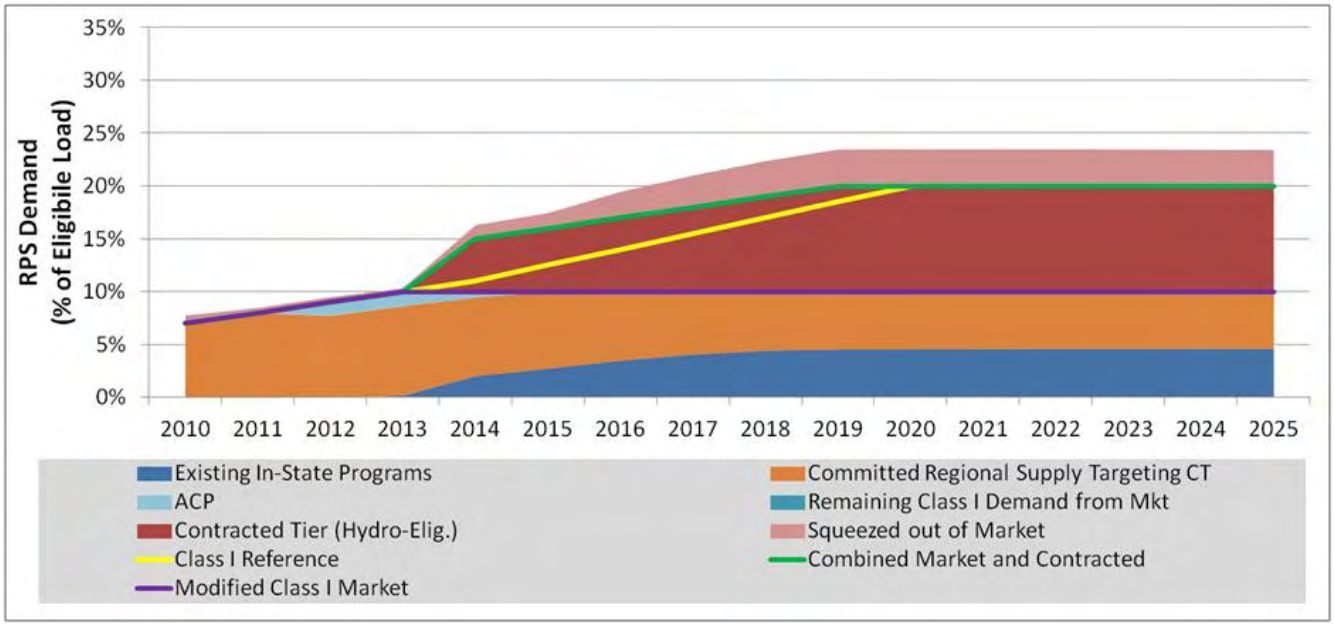


Figure 5 illustrates Scenario 1, which adds a 5% Contracted Tier under a 20% by 2020 total combined Class I target. It is added as a block that increases from 2.5% in 2014 to 5% in 2020. W From 2013 through 2020, the combined totals exceed the current RPS trajectory somewhat. The Market Class I

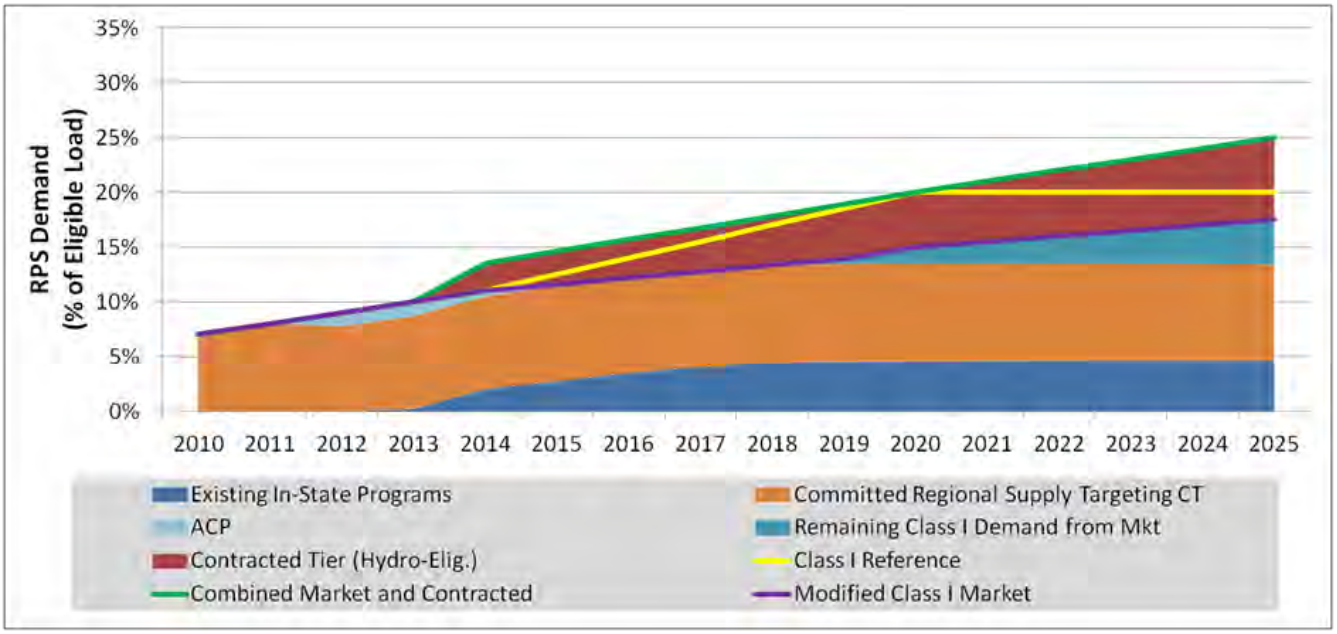
Tier, however, ramps up more slowly and is capped at 15% of load by 2020. While this scenario does not displace any supply currently targeting the Connecticut class I market, it would displace any opportunity for incremental market resources until after 2019.

Figure 6. Scenario 2



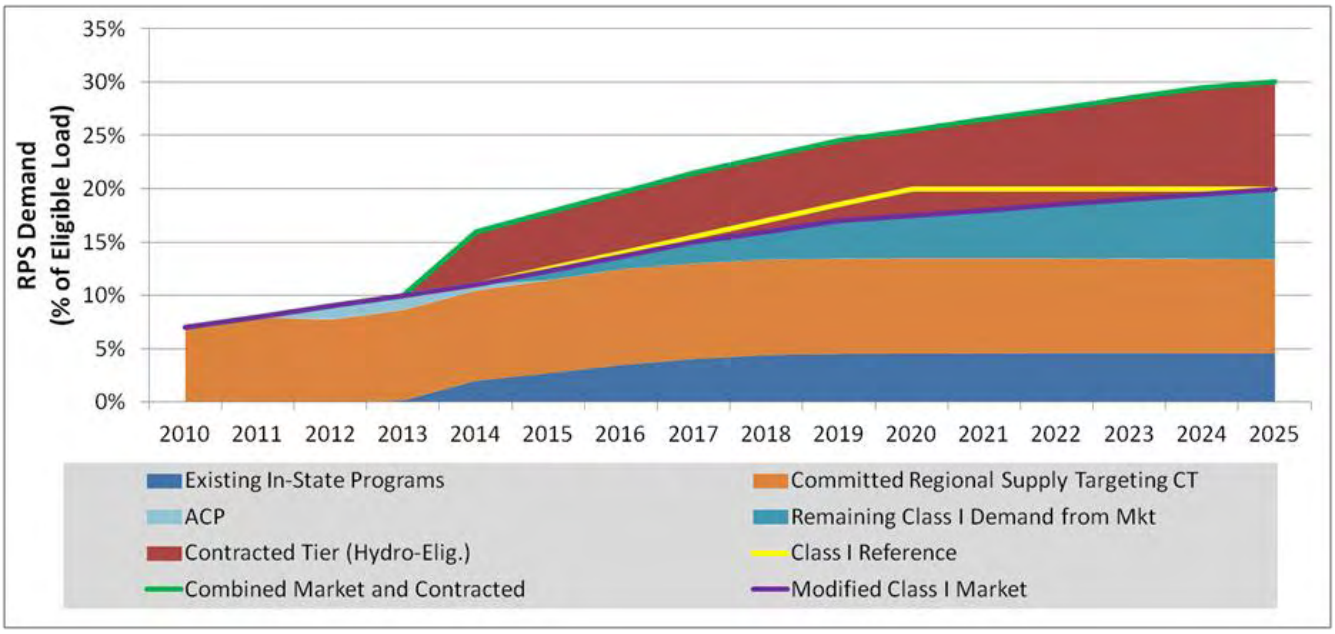
Under Scenario 2, the combined Market and Contracted Class I Tiers reached 20% by 2020, but load-growth after 2013 is met from the Contracted Class I Tier. This scenario represents the most dramatic change from the status quo modeled in this analysis. The Contracted Class I Tier increases from 5% in 2014 to 10% in 2020, while the Market Class I Tier demand is capped at 10% from 2013 onward. A significant portion of the existing and committed supply targeting Connecticut is pushed out of the market (represented by the rose layer); while there would be no room for additional market resources to meet the Market Class I Tier. This scenario would dramatically decrease ratepayer costs, and essentially eliminate any risk of ACP payments, but would come at the expense of any continuing support for in region supply.

Figure 7. Scenario 3



Under Scenario 3, the combined Class I RPS target increases to 25% of eligible load in 2025. By 2025, 7.5% of this total comes from the Contracted Class I Tier, with the Market Class I Tier reaching 17.5% by 2025, down from 20% by 2020 under current rules. The Market Class I Tier in this scenario tracks Scenario 1 through 2015, but continues to grow another 2.5% by 2025. Likewise, the Contracted Class I tier also grows another 2.5% by 2025. Compared to Scenario 1, the Contracted Class I tier allows for greater contribution from regional supply to the Market Class I Tier after 2020.

Figure 8. Scenario 4



Scenario 4 is the most aggressive outlook modeled as part of this analysis. The total combined Market plus Contracted Class I RPS target reaches 30% in 2025, with most of the addition coming from an incremental 5% Contracted Class I Tier commencing in 2014, which increases to 10% of load by 2025. The final Market Class I Tier target reaches 20% in 2025, rather than 2020, effectively slowing the increase in market class I targets during the period in which availability of adequate supply is less certain. This scenario reduces the Market Class I RPS targets somewhat, thereby reducing ratepayer costs after 2017.

5.5 Conditional Flexibility

An illustrative example of applying a conditional flexibility mechanism in response to market conditions was also examined. Such a mechanism - which could be combined with any set of targets - could provide policy makers an opportunity to build in market flexibility and ACP risk protection in an innovative way that does not shock the Market Tier in the short term.

There are many unknowns that influence the tradeoffs among conflicting objectives discussed in Section 2. This uncertainly will also impact the ultimate relative cost premium associated with different approaches considered to meeting the Combined Class I RPS targets. As pointed out in Section 5.3, there is considerable uncertainty in the future availability of, and therefore timing of the need for, additional RPS-eligible generation. The supply-demand balance depends on a range of uncertainties regarding the successful development of planned generation and transmission, as well as policy decisions in each New England state and at ISO-NE. Another uncertainly is the longer-term availability, nature and magnitude of Federal renewable energy incentives (i.e. Production Tax Credit (PTC), Investment Tax Credit (ITC)) beyond the recent short-term extension.[34] If such incentives continue to be available, any cost premium for the Market Class I Tier for in-region supply would be less, while expiration, phase-down or phase-out would increase the cost premium for the Market Class I Tier. A third uncertainty is the presence or absence of incremental greenhouse gas restrictions beyond the current RGGI program cap, either regionally (enhancement of RGGI via lowering the cap) or Federal action such as carbon cap and trade. All else being equal, a higher carbon price reduces the cost premium of Market Class I resources.

In the presence of such uncertainties, Connecticut may best be served by maintaining a degree of flexibility to adjust the scale of a Contracted Class I Tier and/or the Market Class I Tier, so long as such flexibility mechanisms recognize certain RPS best practices, including making any such potential changes:

- clear;
- limited and well-defined in range (i.e. adjustments to the future glide path rather than reductions to target levels already achieved or to be achieved by advanced development activities);

[34] In January of 2013, the PTC was extended to apply to projects that are under construction (according to conditions to be established by the Treasury Department) by no later than December 31, 2013. Qualifying projects may elect a 30% ITC in lieu of PTC.

- predictably triggered; and
- implemented with adequate lead time.

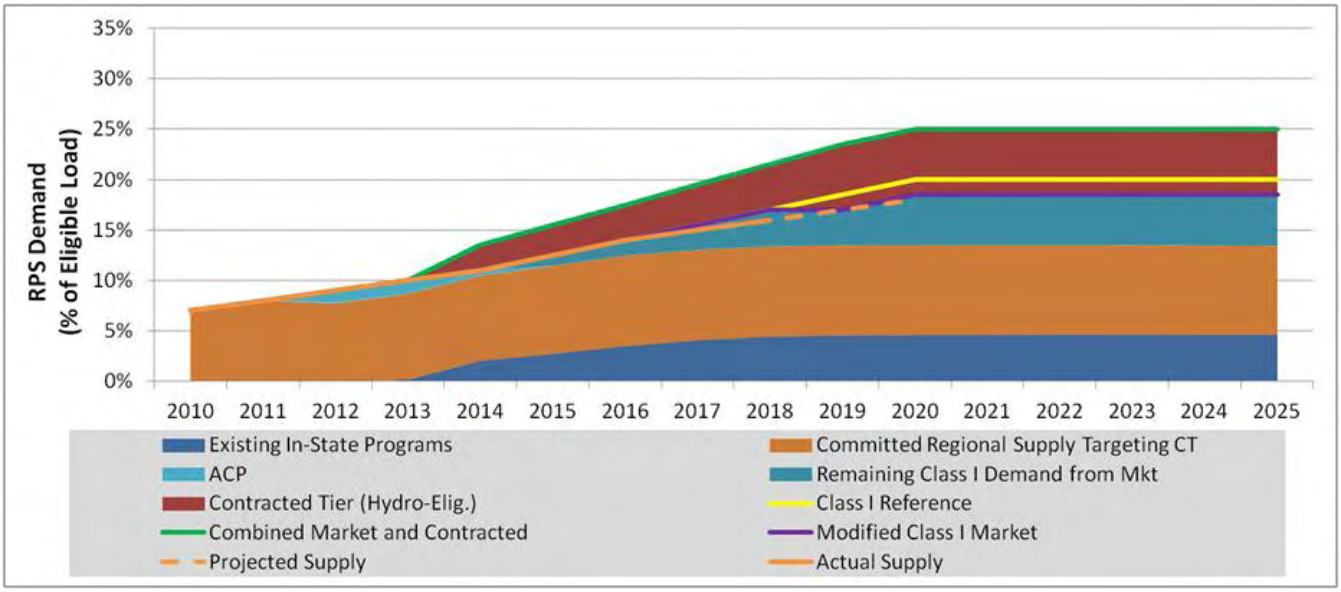
So long as the flexibility mechanism acknowledges past private investment decisions in response to the RPS policy and also the necessity of encouraging additional investment, such an approach can help ensure that Connecticut ratepayers are protected from unreasonably high costs and can make adequate progress towards goals under a range of future circumstances.

Two examples of flexibility mechanisms which might be considered include:

- Responding to supply-demand divergence: If material ACP reliance or supply shortage is experienced, and expected to continue for a sufficiently long period that suggests a long-term divergence of supply and demand (i.e., inability for sufficient supply to respond price signals to meet demand, for example, 3 consecutive years), the ramp-up of Market Class I targets could be slowed and replaced by additional Contracted Class I commitments; or
- Responding to expected increase in cost of eligible generation: This approach could entail adjusting targets based on future availability of federal incentives and/or carbon price, by shifting a larger share of incremental target increases from Market to Contracted Class I RPS tier if combined federal tax (or similar) incentives plus carbon price falls below a defined benchmark.

An example of how such a mechanism could work is illustrated in Figure 9. In this illustration, it is assumed that a supply shortage appears in 2017 and continues through 2020 (a divergence of supply and demand). In this situation, the RPS policy could include a conditional trigger mechanism, which would alter the demand trajectory when such a divergence is anticipated. For example, the subsequent rate of increase for the Market Class I RPS Tier could be moderated under these conditions, with the Contracted Class I Tier increased to pick up the slack and maintain the combined targets. The example shifts one year of Market Class I growth to the Contracted Tier. While the Combined Class I target for 2020 remains unchanged, the delay shifts demand from the Market Tier to the Contracted Tier and allows the regional supply to catch up with Market Class I Tier targets. As described above, this can be an effective way to make minor market adjustments that protect ratepayers in a way that is fully transparent to market participants.

Figure 9. Scenario 5: Illustrative Example of Conditional Flexibility Mechanism



6 Transaction Structure

As noted in Section 2.3, constraints on the ability to implement a Contracted Class I Tier as envisioned in this white paper include Connecticut's market structure and limitations on the authority of state agencies. In particular, there is no jurisdiction to compel competitive retail suppliers, who now serve the lion's share of retail load in the State, to enter into PPAs under a Contracted Class I Tier.[35] Further, such PPAs may adversely affect the EDCs' balance sheets. In addition, additional changes to how supply is purchased would be on top of recent modifications to the way that the EDC's procure Standard Offer/Last Resort (SO/LR) supply. Those changes are reflected in the procurement plan recently approved by PURA and more closely track the wholesale market through a portfolio of short-term contracts.[36] While the State's policymakers could decide to alter this approach, doing so would represent a sharp departure from recently established direction. In addition, the volume of Standard Service demand is expected to continue to decrease over time at an uncertain pace. As a result, running Contracted Class I Tier purchases through Standard Service supply would risk having the PPA volume exceed the Standard Service volume at some point in the future. A more commonly used alternative has been to purchase the power for all customers regardless of whether they are served by an EDC or a competitive retail supplier and pass the costs and benefits through the Non-Bypassable Federally Mandated Congestion Charges (NBFMCC).

In considering which transaction structure approaches are feasible and desirable, the scale of potential PPA outlets can be compared against the potential Contracted Class I Tier scale. As noted in Section

[35] About 50% of residential and about 80% of commercial and industrial load.
[36] While some commenters have argued for supplying a portion of this load with long-term contracts, PURA did not adopt this approach.

5.1 the scale of several alternative outlets for Contracted Class I Tier supply may be inadequate to absorb a Contracted Class I Tier PPA of the contemplated scale.

Potential transaction structures need to address a range of issues. These include:

- **Is the transaction physical or financial?** The PPA could provide for either physical delivery of electricity or a financial equivalent. So long as the power supply is delivered into the ISO-NE energy markets, a financial transaction may be able to replicate the direct impacts on rates and, potentially, indirect impact (i.e. price suppression) of physical delivery while steering clear of some of the aforementioned transmission constraints on imports.
- **What is the price structure?** Dimensions of pricing structure include:
    - All-in bundled price for delivered products, or contract-for-differences (i.e. a fixed for floating swap).
    - Fixed, indexed (with or without caps and/or floors), or fixed with periodic adjustments.[37]
- **What products are being purchased**? i.e., commodity (energy, capacity, and/or ancillary services), RECs and other environmental attributes or rights. Because the purpose of the Contracted Class I Tier is for the State to count the purchases towards meeting renewable energy and greenhouse gas goals, it is essential the purchase include the RECs, whether or not there is a price premium paid.
- **Who is the purchaser?** Options include: 1) the EDCs in their role as generation service provider; 2) all RPS-obligated load-serving entities; 3) the EDCs in their role as distribution companies; 4) the State (and potentially local governments) in their role as retail customers 5) an agency of the State, or 6) a special-purpose power authority.
- **What is the disposition of the commodities purchased?** The buyer may or may not have adequate electricity consumption requirements to absorb and use the commodities purchased, so many of the transaction alternatives will require that the commodities be disposed of (settled) in some manner, potentially with a corresponding cash flow.
- **How (and from whom) is money collected to pay for the PPA purchases, and by whom (i.e. what is the collection mechanism)?** The answer to this question encompasses both the immediate source of payments (for example, the EDCs, load serving entities, state agency or power authority) and the ultimate source (e.g., a subset of generation service customers, or all distribution customers).
- **How are costs allocated among customers (ratepayers)?** Options could include allocation to all customers whose load is subject to RPS obligations, or some subset of those customers.
- **What existing or additional statutory authority is required to implement the alternative?** Public Act 11 – 80 gave DEEP substantial authority to procure renewable energy. It seems clear, however, that at least some of the options presented herein would likely require additional legislation and legal authority, which are beyond the scope of this paper. Further discussion presupposes enactment of necessary legislation, if and as needed, to implement the selected alternative.

[37] These characteristics, which are independent of the transaction structure choice, are addressed in Section 8.3.

Table 8 (EDC Options) and Table 9 (Government Options) present, describe and characterize a series of options, as well as summarize the implications, advantages and limitations of the approach. Table 7 provides a key to terms and acronyms used in these tables.

Table 7: Key: Important Acronyms and Abbreviations

Term	Description
EDC	Electricity Distribution Company
CCEO	Connecticut Clean Energy Options
DISCo	Distribution Company
SO/LR	Standard Offer/Last Resort
CfD	Contract for Differences
En	Energy (MWh)
Cap	Capacity (MW)
AS	Ancillary Services (Operating Reserves, Frequency Regulation)
RECs	Renewable Energy Credits (or other environmental attributes)

Table 8: Transaction Structure Options Using EDC as Purchaser for Contracted Class I Tier

Option	Gen Fixed	EDC-Gen Variable	EDC-Gen Market	EDC-Gen CCEO[38]	EDC-DISCo Physical	EDC-DISCo Financial
Description	EDC enters into commodity PPA with generator in role as SO/LR Supplier. SO/LR pricing linked to PPA.	EDC enters commodity PPA in role as SO/LR Supplier. SO/LR pricing linked to PPA priced as index with a floor.	EDC enters commodity PPA in role as SO/LR Supplier. SO/LR pricing tied to spot.	EDC enters commodity PPA in role as SO/LR Supplier. SO/LR customers may opt in, pricing tied to PPA.	EDC enters commodity PPA in role as DISCo	EDC enters a contract-for-differences.
Analogs	None	None	RI Long-Term PPA policy	Modified CCEO	Project 150	Similar to CT's peaking purchases
Physical vs. Financial	Physical	Physical	Physical	Physical	Physical	Financial
Price Structure[39]	Bundled all-in	Bundled all-in	Bundled all-in	Bundled all-in	Bundled all-in	CfD
Products Purchased[40]	En, Cap, AS, RECs	En, Cap, AS and RECs	En, Cap, AS and RECs	En, Cap, AS and RECs	En, Cap, AS and RECs	RECs
Disposition of Products Purchased	Commodity used to supply SO/LR. RECs to SO/LR customers *or* all customers	Commodity used to supply SO/LR. RECs to SO/LR customers *or* all customers	Commodity used to supply SO/LR. RECs to SO/LR customers *or* all customers	To serve opt-in customers	EDCs resell commodity into market, allocate RECs to *all* DISCo customers.	Allocate RECs to *all* DISCo customers
Collection Mechanism	SO/LR payments	SO/LR payments	SO/LR payments	SO/LR payments	Non-bypassable wires charge to all customers	Non-bypassable wires charge to all customers

[38] Connecticut Clean Energy Options Program. The program allows customers on SO/LR to opt-in to green power offerings. A long-term hedge option was explored in the past but has not yet been developed and made available.

[39] In principle, financial transaction can cover just purchase of RECs (which don't require physical delivery so are financial in nature) or a fixed-for-floating swap (a.k.a. contract for differences, CfD). For a CfD, if market prices below *strike price*, supplier pays EDCs, and vice versa.

[40] In all cases, purchases also include all other environmental attributes, such as GHG credits related to electricity displacement, if applicable, to assure CT can claim full benefits.

Option	Gen Fixed	EDC-Gen Variable	EDC-Gen Market	EDC-Gen CCEO[38]	EDC-DISCo Physical	EDC-DISCo Financial
Cost Allocation	Only to SO/LR customers	Only to SO/LR customers	SO/LR priced using spot index or other purchase proxy, with differences (+ or -) passed thru to all DISCo cust.	To Opt-in customers	All customers	All customers
Statutory Authority	PURA may have authority under current law.	PURA may have authority under current law.	PURA may have authority under current law.	PURA may have authority under current law.	Additional required	Additional required
Analysis (implications, challenges, advantages, limitations)	Significant departure from current SO/LR philosophy. Shrinking SO/LR load, migration risk creates risk that SO/LR<PPA quantity. Only borne by a subset of customers, whose RE% would exceed target, while other customers only subject to market tier, *unless RECs reallocated to all customers.*	Departs from SO/LR philosophy. If (so long as) price = below market, could sink competitive market. However, if floor price becomes above-market, SO/LR customers may leave rapidly, so there is an increased risk that SO/LR volumes could fall below the scale of the PPA.	Compatible with SO/LR philosophy. Shrinking SO/LR load, migration risk creates risk that SO/LR<PPA quantity. If price indexed, can unwind hedging by retail customers	Inequitable. Scale likely to be very small. Impractical to lock in retail customers LT, so unstable. CCEO customers get 100% RE, while all others get Market RPS %.	Equitable. Transaction costs assoc. with elec. purchase and resale. If price indexed, can unwind hedging by retail customers.	Equitable. Simpler than physical model, avoids transaction costs assoc. w/ elec. purchase and sale. If price indexed, can unwind hedging by retail customers.

Table 9: Transaction Structure Options With Government Purchaser for Contracted Class I Tier

Option	Gov't Loads	State Agency	Power Authority – Physical	Power Authority - Financial
Description	State (and local) Government Loads enter PPA	Central procurement by state agency (e.g. DEEP) enters PPAs funded by SBC collections.	Power Authority established to enable Contracted Class I Tier commodity PPA.	Power Authority established to enable Contracted Class I Tier contract-for-differences
Analogs	CT Clean Energy Communities, voluntary or statutory commitment (ex: NY Executive Order 111)	NY RPS Main Tier Central Procurement	VT DPS LT PURPA purchases (?), modified IL Power Agency; previously proposed RI Power Authority	?
Physical vs. Financial	Physical	Financial	Physical	Financial
Price Structure[41]	Bundled all-in	CfD	Bundled all-in	CfD
Products Purchased[42]	En, Cap, AS and RECs	RECs	En, Cap, AS and RECs	RECs
Purchaser	Multiple Gov't agencies, run by a single agency	State Agency (e.g. DEEP)	Power Authority	Power Authority
Disposition of Products Purchased	To gov't purchasers	RECs to all DISCo customers	PA resells commodity into market, allocate RECs to *all* DISCo customers	Allocate RECs to *all* DISCo customers
Collection Mechanism	Payments by gov't purchasers	Wires charge to all customers	Wires charge to all customers	Wires charge to all customers
Cost Allocation	Gov't purchasers	All customers	All customers	All customers
Statutory Authority	?	Additional required	Additional required	Additional required

[41] In principle, financial transaction can cover just purchase of RECs (which don't require physical delivery so are financial in nature) or a fixed-for-floating swap (CfD). For a CfD, if market prices below *strike price*, supplier pays EDCs, and vice versa.

[42] In all cases, purchases also include all other environmental attributes, such as GHG credits related to electricity displacement, if applicable, to assure CT can claim full benefits.

Option	Gov't Loads	State Agency	Power Authority – Physical	Power Authority - Financial
Analysis (implications, challenged, advantages, limitations)	Inequitable. Gov't customers get 100% RE, while all others get Market RPS %.	Simple. Equitable. Avoids transaction costs assoc. w/ elec. purchase and sale. Minimal interference with market structure. Places administrative burden on state agency. If price indexed, can unwind hedging by retail customers.	Similar to EDC-DISCo Physical. Equitable. Transaction costs assoc. with elec. purchase and resale. If price indexed, can unwind hedging by retail customers. Challenging and complex to implement, with time and difficulty to establish, establishing creditworthiness.	Similar to EDC-DISCo Financial and State Agency models. Equitable. Simpler than physical models. Avoids transaction costs assoc. w/ elec. purchase and sale. . If price indexed, can unwind hedging by retail customers. Challenging and complex to implement, with time and difficulty to establish, establishing creditworthiness.

Based on the analysis contained in Table 8 and Table 9, the most promising and least disruptive option for transaction structure would be the "EDC-DISCo Physical" described in Table 8. Approaches which rely on the EDCs to procure in their role as generation service provider are less ideally matched due to the shrinking load associated with EDC supply of generation service to retail customers. Associating purchases with CCEO were state agency load also suffer from potentially inadequate scale, as well as unequal distribution of cost and benefit. Establishment of a state power authority is a very complex undertaking, which would require additional legislation as well as substantial lead time to set up, staff, and execute.

Under the "EDC-DISCo Physical" approach, DEEP and EDCs would collaborate on a transparent and competitive process to seek proposals for PPAs to fulfill the Contracted Class I Tier. The EDCs would execute the PPAs and administer them, purchasing all electricity products and RECs. The benefits and costs associated with these purchases would accrue to all electric ratepayers of the distribution companies. RECs would be retired in association with Connecticut ratepayers, energy and capacity procured would be sold into the NEPOOL markets, with any cost or benefit passed on to all electric ratepayers through non-bypassable distribution rates. This approach is similar to that being used by Massachusetts and fulfillment of its Section 83A long-term renewable energy contracting mandate. In effect, these approaches can be framed as the Market Class I RPS Tier being imposed on generation service providers, with the Contract Class I Tier being imposed on the EDCs, and the sum of the RECs procured under both comprising the percentage of the total class I renewable energy goal. We note that the "EDC-DISCo Financial" approach described in Table 8 could alternatively be used to accomplish the same objective using financial rather than physical transactions. This approach might reduce administrative costs by obviating the need to resell energy and capacity.

7 Transmission

The role of transmission in a Contracted Class I Tier is important because it can impact the timing, quantities, cost, reliability and other impacts of the contemplated purchases.[43] How it is treated also determines how alternatives competing to supply the Contracted Class I Tier are considered, and whether there is a level playing field among options.

7.1 Transmission-Related Issues Associated with Contracted Class I Tier Sources

For the purposes of this analysis, we consider imported supply over existing ties to neighboring control areas, new ties to neighboring control areas, and new transmission within New England to access large-scale renewable energy supply.[44] Table 10 summarizes the transmission issues associated with various alternative sources eligible to supply the Contracted Class I Tier.

[43] Reliability issues associated with the size of a Contracted Class I Tier purchase are addressed in Section 5.1.

[44] For purposes of this analysis, the discussion will focus primarily on land-based wind power that can be developed at large scale if transmission is built. However, it should be noted that, while costs today make it less likely to compete in he Contracted Class I Tier, similar issues also apply to offshore wind, conveyed to load centers directly via either direct radial

Table 10: Transmission Issues Associated with Contracted Class I Tier Sources

Supply Option	Quebec Hydro	Quebec Hydro	Maritimes Hydro	New England Wind	New England Wind	New England Wind
Transmission Path, Facilities	Existing HVDC line	Northern Pass	Existing MEPCO, NRI AC lines, plus new upstream upgrades e.g. (Northeast Energy Link, Green Line or other.	Radials + Upstream Upgrades, e.g. (Northeast Energy Link, Green Line or other.[45]	Network Facilities + Upstream Upgrades	Independent transmission company (ITC) dedicated line
Access	Primary or Secondary market for right	Participant funded contractual rights	Participant-funded contractual rights and/or open access tariff	Generator ownership or interconnecting utility ownership with contractual rights	Open access tariff, or open-season-style pre-commitment	Open-season pre-commitment
Timing	Available near-term	~2018	~2018	~2015 or later	~2016-17 or later	~2017 or later
Price Suppression[46]	To the degree PPA exceeds business-as-usual imports over facilities	incremental	incremental	incremental	incremental	incremental

cables (assumed paid for by the generator) or offshore network facilities (where some costs may be allocated to transmission customers).

[45] Upstream upgrades may be required for capacity deliverability in many but not all cases.

[46] This row describes *energy* market price suppression, consisting of (i) *electricity* price suppression, the bid stack effect on locational marginal energy prices resulting from adding low-variable cost generation to a bid-based market, benefiting all electricity consumers in the local area where generation is displaced; and (ii) and natural gas price suppression resulting from reduced natural gas demand caused by displacement of natural gas-fired electricity generation, benefiting all natural gas consumers in the market area where generation is displaced. These are distinct from the *REC* price suppression that may be realized by reducing Market Class I demand via shifting that demand to the Contracted Class I Tier.

Supply Option	Quebec Hydro	Quebec Hydro	Maritimes Hydro	New England Wind	New England Wind	New England Wind
How Transmission may be paid for	By HQUS, embedded in price	Proposed as HQUS participant-funded, utility owned	TBD, probably participant-funded, utility-owned	Generator	Generator, and (*potentially*) a share of costs allocated to network transmission customers attributable to reliability benefits accruing to those customers.	ITC, but Generator pays ITC, and such costs embedded in price.

One additional factor that may require consideration is the impact that different utilization of existing ties would have on ISO New England reserve requirements. Interties to NEPOOL's neighbors that are fully utilized, versus those with available space whose usage can change in response to emergency situations, factor differently into the calculation of ISO New England reserve requirements. While analysis of this issue is beyond the scope of this white paper, it may merit further consideration in evaluating Contracted Class I options and in setting procurement evaluation criteria.

7.2 Level Playing Field

A level playing field is important to making well-informed choices between alternatives so that the impact of decisions is not masked by hidden costs and benefits or differential treatment of varying competitive options. With respect to transmission issues,[47] a level playing field can be achieved by considering:

- The cost of required transmission to enable an option. The specific costs might differ between, for example, Canadian hydro and New England wind, but at scale, both may require transmission investments not traditionally considered as part of the cost of interconnected generation. The method of evaluating alternative options should include both internalized (sometimes referred to as participant-funded) transmission costs that are included in the delivered price proposal of a bidder, as well as costs allocated by ISO to Connecticut transmission customers (i.e. that portion of network upgrades deemed incremental to investments required for reliability purposes or creating sufficient reliability benefits to be justified on a basis other than bringing renewables to market).
- PPA duration and its impact on the transmission component of PPA price. For instance, compare the cost of transmission needed to bring New England wind to market, if that cost is borne by the generator, as opposed to the participant-funded transmission costs of new facilities to bring Canadian Hydro into New England (e.g. Northern Pass). If the cost of

[47] Other differences in value, such as between firm, scheduled power and variable power supply, are considered in the discussion of evaluation criteria in Section 8.5.

transmission for New England wind is amortized over a 15 year PPA, while the cost of transmission needed to import Canadian hydro is amortized over a period longer than 15 years (i.e., 20-30 years), it is possible that the embedded per-MWh cost of transmission could be lower for imported hydro solely because of the different amortization period. Providing competing sources with equivalent periods over which to amortize transmission costs would level the competitive playing field.

- In addition, because independent power producers do not have the protection of the regulatory compact, they typically have a higher cost of capital than regulated utility investments. Therefore, if transmission associated with Canadian hydro imports is treated as a regulated investment, and New England-based onshore or offshore wind radial interconnections are funded by IPPs, there may be an implicit bias towards the lower price that results from the treatment of transmission investment financing.

While there may be nothing Connecticut can do about any embedded transmission cost differential resulting from the conditions described above, there may be an element of control Connecticut could exert (i.e. via ISO-NE decisions) over the time period that costs associated with transmission are amortized, and over the ownership and cost of capital of such investments. Connecticut is best served by acting to level the playing field to the degree within its power, as doing so will enhance price competition.

8 Procurement Details

8.1 Sole Source Negotiations vs. Competitive Procurement

Options available to CT for securing a firm offer for the Contracted Class I Tier include direct bilateral negotiations, competitive solicitation or a hybrid including seeking expressions of interest and indicative proposals, followed by negotiations with the most attractive respondents. Each approach has its pros and cons.

Options:

1. ***Competitive procurement.***
    a. Advantages: A level of transparency and confidence that the best price has been secured, by means of a competitive process, is appropriate for a public process; with multiple potential suppliers, competitive dynamics may lead to both more favorable pricing and a more solid justification than Option 2; other technologies or entities might be able to compete, and at least will provide competitive pressure.
    b. Limitations: Increased complexity, longer lead time to implement.
2. ***Bilateral Negotiations.***
    a. Advantages: Simplicity; Faster resolution and implementation than other options; more direct means to engineer transaction to facilitate getting new transmission built, more certain to drive that specific investment (although these features can be addressed in any option).
    b. Limitations: Lack of transparency typically a part of public policy initiatives, and inability to represent that the best price was secured.
3. ***Solicit Expressions of Interest and Indicative Pricing, Followed by Bilateral Negotiations.***

a. Advantages: Provides greater comfort with a competitively-derived option and price than Option 2, while potentially allowing more rapid implementation and customization of the solution.
b. Limitations: Less transparency than Option 1, less certainty of best price than Option 1 as indicative proposals are rarely firm.

Recommendation: Option 1. Options 2 might be considered only if speed is of the essence.[48] Option 3 might be considered if supply alternatives were expected to offer such radically different features, price structures and benefits, that crafting a procurement process with transparent evaluation metrics and criteria that could accommodate such diverse options was deemed impractical.

8.2 Products

The Contracted Class I Tier PPA could procure any combination of energy, capacity, ancillary services, RECs and other environmental attributes. As discussed in Section 5, the PPA could be for either a physical energy transaction, or its financial equivalent. We recommend that the PPA procure all of the above-referenced products if the purchase is a physical energy product, or just procure RECs and associated environmental attributes if a financial transaction.

Contracting for new generation requires a creditworthy contract to secure financing. A single contract that secures the full revenue stream – i.e. a fully bundled PPA conveying all products – over a long term is likeliest to yield the lowest price. From the project investor perspective, a PPA that includes all products reduces a range of risks, which can yield a lower cost of capital and levelized cost of energy than PPAs which leave market pricing risk on the generator. From Connecticut's perspective, a bundled purchase of energy, capacity, ancillary services, RECs and other environmental attributes also serves as a hedge against price variations in the energy and REC markets. If electricity prices go up, REC premiums go down; if electricity prices fall, the REC premium can appear or increase. When electricity prices are near historic lows, a PPA is more likely to yield a favorable hedge value than one which requires price increases to be favorable.

A financial transaction structured as a contract-for-differences (CfD, also known as a fixed-for-floating swap), so long as it includes delivery of the RECs and associated environmental attributes, is the financial equivalent of a bundled physical transaction. In effect, it provides only for the delivery of RECs and environmental attributes, with pricing fluctuating with the value of commodity production.

Whether the PPA is a bundled PPA or a CfD, the transaction would include transmission costs allocated to and incurred by the generator.

[48] We note that SEA's analysis described in Section 5, as well as the 2012 IRP (Connecticut Department of Energy & Environmental Protection, 2012), suggest that, once projects under construction or PPA (including Cape Wind) are built, a material shortage or supply gap, and therefore material reliance on ACP, is not expected for several years thereafter, and this, speed may not be at a premium.

8.3 Pricing

Aspects of PPA price include price structure, delivery point at which the price is quoted, and, potentially, some additional characteristics. Issues and choices associated with each are discussed in this section.

Price Structure. As indicated in Section 2.1, a primary objective of the Contracted Class I Tier is to procure electricity supply that meets the stated policy objectives at little or no premium relative to projected cost of commodity electricity. In the context of a competitive procurement, there are two alternative approaches to seeking assurance that a price offered under a long-term PPA proposal will not represent a cost premium:

- **Comparison against a forecast.** Under this approach, CT could solicit proposals that are either fixed price or indexed (e.g. to inflation). Bids could be compared against a value-adjusted 'business as usual' forecast of electricity prices for comparable products.[49] A bid price at this cost benchmark would represent no premium, and a price below the benchmark would represent a savings, relative to *expected* electricity costs. Applying this approach requires development of a forecast and a method for value adjustment. The forecast benchmark could be used as a threshold price, above which Connecticut would reserve the right not to enter a PPA. Such a benchmark should be kept confidential to mitigate the risk that bidders would cluster their bids just under the benchmark, potentially depriving Connecticut of the benefits of competition.[50]
- **Comparison against future energy prices.** Under this approach, CT could seek proposals that are indexed at a fixed discount to either annual or seasonally-weighted energy LMPs at a designated zone (e.g. the ISO-NE Connecticut zone). Such an index would ensure that any purchase would always create savings. In practice, we do not expect such an approach to be viable without allowing the bidder to propose a price floor. Without a floor, there is no value to the bidder who needs to have a minimum level of revenue certainty to finance generation or transmission facilities. A supplier that is always able to sell into the ISO-NE spot market without a discount would have no incentive to offer a discount without a price floor.

Delivery Point. Price offers for a physical contract need to specify a delivery point at which the pricing applies. To impact the power supply mix, the power needs to be physically delivered within New England. To influence the cost of electricity supply for Connecticut electricity consumers, the energy needs to appear in (or be capable of appearing in) the ISO-NE settlement account of a Connecticut load-serving entity (LSE). Similarly, a financial transaction also needs to specify the location at which the pricing applies. Pricing at the ISO PTF (pool transmission facilities) within any New England zone incorporates the direct cost of transmission necessary to deliver to the New England PTF. A price delivered to the Connecticut (or SW CT) zone reflects the cost of network transmission within New England. A generation source need not procure transmission to deliver to the Connecticut Zone, because if delivered to the PTF and included in an LSE's settlement account, delivery is billed to the LSE by ISO-NE under the LSE's network transmission service. The cost to the LSE includes the costs of congestion and losses. Similarly, for capacity to be of value to Connecticut, there also needs to be

[49] See discussion in Section 8.5 on how a value-adjusted price may be used for the purposes of comparing bids.
[50] Such an approach is used by NSYERDA and the Illinois Power Agency for their RPS central procurements.

capacity deliverability. To compare prices offered (or a price to a forecast), prices need to represent a price delivered to a common point defined in the solicitation. Choices include:

- **Priced at NEPOOL PTF:** In this approach, the CT buyer takes the basis risk between the PTF injection point and the CT delivery point. If comparing between offerings injected at different locations, this makes comparisons dependent on a forecast of future basis differentials between ISO zones, an added complexity. However, because it is impossible for generation sources to hedge such basis risk over the course of a long-term contract (in ISO-NE, financial transmission rights can only be hedged over shorter term), the bid price may be less than the alternative. This is because the bidder would not be required to build a risk premium into the price to cover the unhedgeable basis risk.
- **Priced at CT Zone:** This approach is easier to evaluate, as prices can be compared head-to-head without adjustment for transmission congestion from different locations. However, there is a risk that the price would be higher, as generation sources would likely build in a risk premium to cover the unhedgeable basis risk.

Additional Potential Pricing Features. There are other potential pricing features which could be considered. Examples include:

- **Terminal purchase or PPA option.** Since a primary objective of the Contracted Class I Tier is ratepayer savings, it is worth considering whether an option to either own the generation source(s), or purchase their power at below market prices, at the end of the PPA term can be secured. The legacy hydro resources of New England whose capital costs have long been paid off represent the 'cash cows' of the industry, often churning out energy with ongoing operating costs below the market value of their energy. Likewise, today's new, capital-intensive renewables might potentially be tomorrow's cash cows once their high upfront costs are paid off, if they can continue to operate below market energy prices. The upside of a long-term supply of paid-off, below market generation for Connecticut electricity consumers can only be realized, however, if the supply continues to be controlled after the term of the PPA concludes; otherwise, the owner will make it available into the market at market prices. Post-PPA control of a below-market-price resource could be secured through either an option – the right without the obligation - to either purchase the facility, or to extend the PPA at a favorable, lower price. While a provincially-owned utility is unlikely to be willing or able to convey an option for partial ownership of its generation resources supplying the PPA at the end of the contract, the situation may differ for IPP generation. The owner of a new renewable resource within New England, who may be able to utilize the Contracted Class I Tier PPA to get a new project (and perhaps associated transmission) built, may be willing to offer such a terminal option at an attractive price.
- **Creative finance and prepayment options**. Another example of a pricing structure would be a prepayment option. While prepayment shifts performance risk to the buyer (which should be addressed in contractual terms and conditions, liquidated damages, etc.), it has the benefit of dramatically reducing the overall cost of financing for an IPP generator. In effect, it substitutes the cost of capital (or discount rate) of the buyer for that of the seller. If the buyer (an EDC or the state) is able to finance (securitize) a prepayment at a substantially lower cost of capital than the IPP cost of capital, such an option may be economically attractive to the buyer.

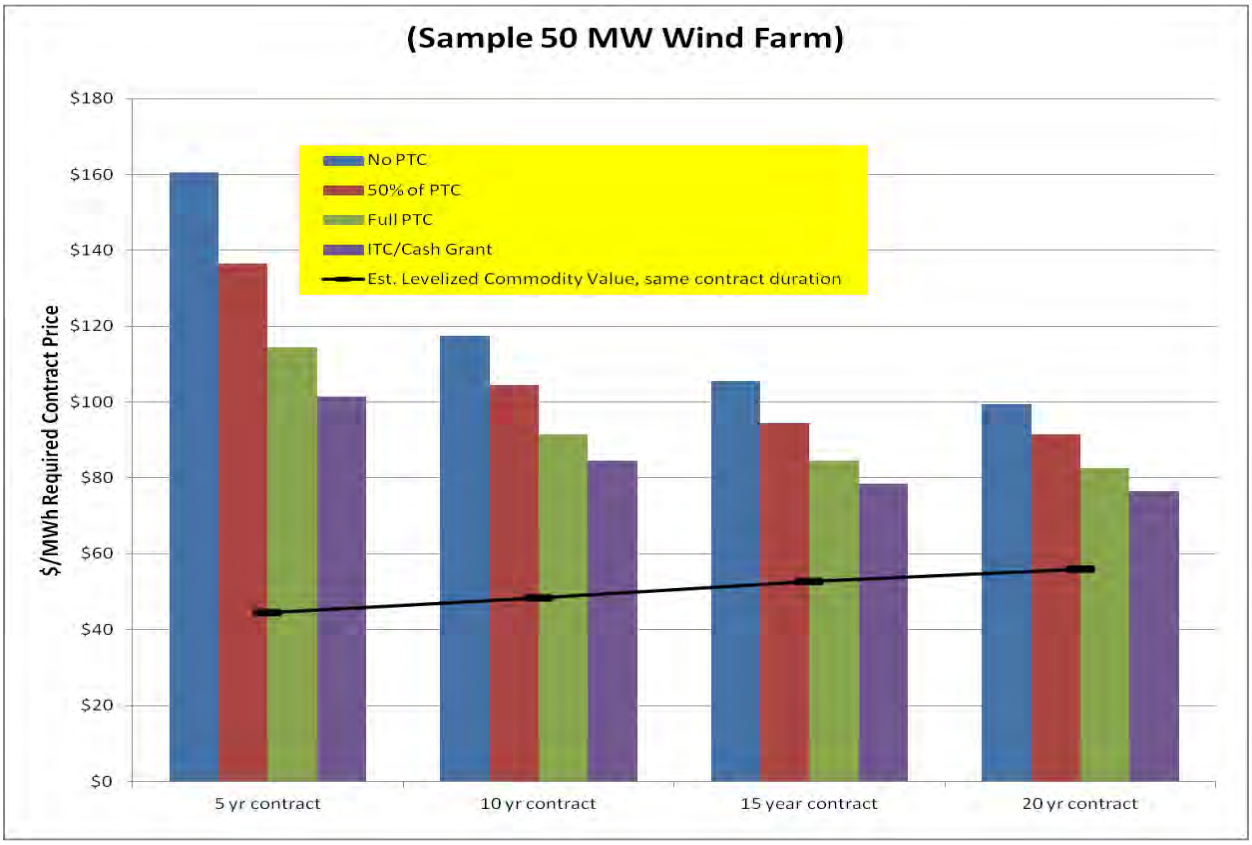
Because the provincial owners of large-scale Canadian hydro are already bringing low-cost government financing into play, this is unlikely to be an attractive option for Canadian hydro resources; however, it may allow IPP generation (whether within New England or an adjacent control area) to compete more aggressively on a leveled playing field.

8.4 Contract Duration and Cost Dynamics

The PPA duration for the Contracted Class I Tier will have a significant impact on the price. The primary reason for this relationship is that most of the cost of capital-intensive technologies like hydro or wind is the up-front capital investment. The duration of revenue from any PPA drives the reliability of the revenue stream, which in turn drives two key determinants of the cost of energy (and the required per-unit PPA revenue): how long the up-front fixed costs can be amortized, and the cost of capital. The duration of these contracts not only impacts the contract price, but also which parties (and technologies) will be able to realistically compete for the contract.

In general, longer term amortization of costs and increasing the debt term – often referred to as its 'tenor' - can both put significant downward pressure on the levelized cost of energy (LCOE). As shown in , a longer term amortization of up-front costs enabled by a longer duration of revenue stability can, under some circumstances, offset the loss of tax incentives. illustrates this effect, as well as the general price effects of long-term contracts. The other important takeaway here is that, depending on the relative cost and value, the *premium* (cost over commodity market value of production) can in some circumstances shrink proportionally by more than the increase in duration as the contract duration is extended. At the extreme, if the contract duration is long enough, when compared to the commodity value of energy (illustrated by the black line in), the most cost-effective renewables *might* be able to be procured with zero premium, which is the ultimate goal of any Connecticut program revision.

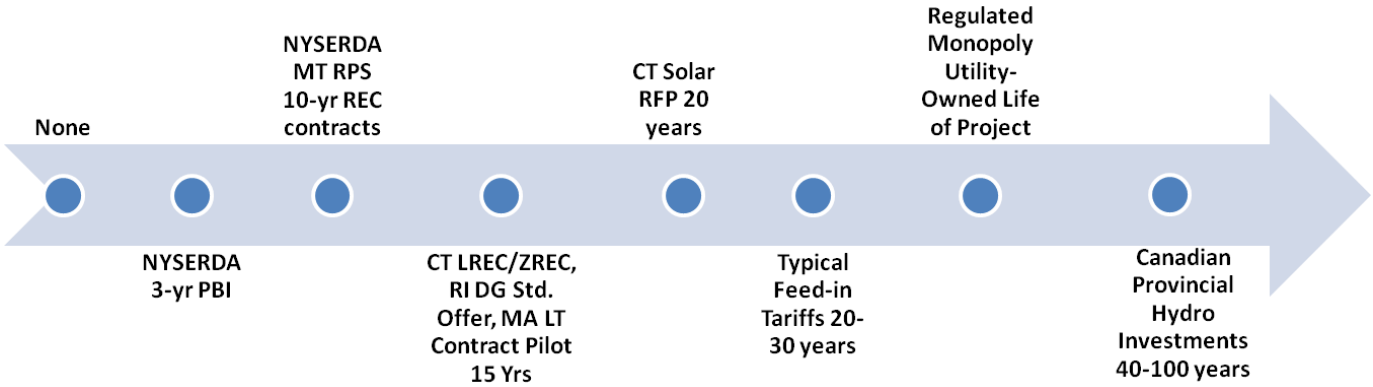
Figure 10. Comparative Effects of Tax Benefits and Contract Length on Energy Price



(*Note, the numbers here are for illustrative purposes only*)

Perceptions about the relative cost of different technologies and resources are sometime distorted by the implicit duration of fixed cost amortization. As shown in Figure 11, various regional programs provide very different durations of support to generators. The expected cost per MWh of New England onshore wind, for example, is usually associated with the bundled contract prices for 10 to 15 year bundled PPAs that have been offered to wind generators in the region. Many policy-driven PPA durations for traditional Class I renewables fall in the 10-20 year range (including Connecticut's Solar RFP and LREC/ZREC programs). In contrast, Canadian provinces undertake development of their provincially-owned hydro resources with a very long investment time horizon, effectively amortizing their fixed costs over 40-100 years. This long-term perspective provides a significant advantage in terms of the PPA price that they can consequently accept for Canadian hydro power. The key point here is that differential government support may be a factor behind *perceived* lower cost that would not be the result of a level-playing-field assessment of resource costs.

Figure 11: Examples of Revenue Certainty across Regional Programs



The relationship of price to contract duration suggests that price benefits for Connecticut might increase in proportion to the length of the contract. Connecticut should therefore consider approaching this solicitation under neutral terms, offering extended and equal contract terms to any technology, such that other renewables (specifically large wind) may be able to compete on the same basis.[51]

Options: Options for PPA purchase duration include:

1. ***If Contracted Class I Tier PPAs are fulfilled via bilateral negotiations with new, large scale Canadian Hydro:***
    a. 15 year contract
        - Advantage: Consistency with term of other in-state programs (e.g. LREC/ZREC);
        - Limitation: May not be least-cost.
    b. 25+ year contract
        - Advantage: Longer contract might drive costs down, as it may be more effective in supporting the financing of new transmission.
        - Limitations:
            - If Canadian utilities have a bullish long-term outlook on the value of the power supply, and do not require the PPA in order to commit financing, the sellers may be less willing to discount price for a longer duration PPA than the owner of a generation facility requiring the PPA to secure financing.
            - Possible constraint: Treatment of longer term as a capital lease by EDCs, if they are the contracting counterparty.
2. ***If Contracted Class I Tier PPAs are fulfilled via a competitive solicitation open to any Class I technology:***
    a. 15 year contract
        - Advantage: Consistency with term of other in-state programs (e.g. LREC/ZREC);

[51] An important caveat is that the economic life of different technologies is not necessarily the same, and different technologies may require overhauls or refurbishments at different timeframes. These factors require further consideration during a procurement design and implementation phase.

- Limitation: May not be able to achieve contract at no premium to expected market price or may not allow other renewables to be cost-competitive with large-scale hydro

b. 25+ year contract (should not exceed project technical life)
   - Advantages:
     - Longer PPA duration will drive costs down for projects not yet financed;
     - Leveling the playing field between IPP generation and provincially-owned generation
     - Increases likelihood of procurement at no premium to market (e.g. if contract term is long enough, may allow large wind and associated transmission to compete)
     - More defensible approach from a cost perspective
   - Possible constraint: treatment of longer term as a capital lease by EDCs, if they are the contracting counterparty

c. Solicit a variety of contract durations, e.g. 15, 20, 25 and 30 years.
   - Advantage: Allows comparison across multiple terms; as different bidders may place different value on different commitment duration, it is hard to know what PPA duration is least cost. Seeking pricing for a variety of terms would allow Connecticut to identify the most attractive term and supplier.
   - Limitations: Evaluation likely to be more complex, depending on the nature of offers.

Recommendation: A longer term encourages more competition and may result in more attractive pricing, while seeking proposals for a variety of contract durations allows the identification of the most attractive alternative. Both of these options should be pursued and considered in a procurement design and implementation phase.

8.5 Evaluation criteria

A competitive solicitation for a Contracted Class I Tier should consider a *primarily* cost-based set of evaluation criteria, such as the following preliminary recommendations:

1. Metric: Use of a transparent metric for either value-adjusted price, or a comparison of price relative to a benchmark for the value of the production, should be utilized. Such an approach will be more effective than a straight price competition in recognizing that on-peak production is more valuable than off-peak, and schedulable supply is more valuable than variable.[52]
2. Contract duration: If pricing is sought for a variety of contract durations, then a method must be applied to evaluate proposals over different durations. Methods that could be used for evaluation include reducing bids to a single metric (e.g. NPV savings/MWh criteria, total savings), or accounting for a common assumption of replacement cost tacked on to the end of shorter duration proposals so all proposals are evaluated over the same duration.
3. Reliability, capacity contribution relative to price;

[52] Because of future uncertainties in the forecasted value benchmark, there may be merit to producing a range of future benchmarks (e.g. low, base and high price futures) to support the decision.

4. Price suppression impact: This criterion may consider that different types of generation and transmittal pathways may have different price suppression benefits.[53] For example:
    a. Incremental supply, delivered to NE, will cause price suppression.
    b. Under a long-term fixed price contract, the contracted quantity will not directly be subject to price suppression, but will have the bid stack effect and reduce LMPs for all end users whose costs are influenced my market LMPs.
    c. If Contracted Class I supply is coming from Hydro Quebec over existing HVDC facilities and simply replacing imports that are currently happening without new long-term contracts, that portion of Contracted Class I replacing only the current, business-as-usual level of imports into the region will not cause incremental price suppression.
5. Transmission costs (if any) not internalized. For example, if the proposed generation source(s) require network transmission expenditures to reach remote sources, any such indirect costs not internalized into the bid price (but rather allocated to CT ratepayers through network transmission rates) may be appropriate to factor into the bid evaluation, if they are truly ties to the procurement and would not otherwise be incurred.
6. If any of the additional pricing features discussed in Section 8.3 are included, they would also need to be factored into the evaluation process.

Because the objectives discussed in Section 2.1 include environmental improvements including contributing to meeting Connecticut's Global Warming Solutions Act goals, the relative environmental benefits should also be considered as a potential evaluation criterion. If greenhouse gas reduction impacts, for example, are perceived as reasonably consistent on a per-MWH basis, then there may be little value on including an environmental evaluation metric. However, as with price suppression, different types of generation with different time-of-production profiles and transmittal pathways may have different emission benefits. Therefore, the evaluation should consider and adjust for this differential impact. For example, if incremental hydroelectric supply is brought to New England over expanded transmission facilities into and/or within New England, or new wind generation is built within New England, fossil fuel consumption and related greenhouse gas emissions would decline materially. On the other hand, a large-scale hydro contract brought over existing facilities from Quebec that have historically been heavily loaded with system power purchases from Hydro Quebec will create additional displacement of fossil fuel production in New England only to the extent that the imports fill the existing HVDC lines at a higher capacity factor; expansion of hydro imports enabled by incremental transmission, on the other hand, would clearly provide increased greenhouse gas reductions.

9 Tracking and Verification

While Connecticut's objectives include not paying a premium over expected commodity electricity costs for Contracted Class I Tier purchases, the lack of premium does not obviate purpose of the

[53] We note that industry analysts differ over the duration of price suppression impacts, as well as the degree to which they should be considered benefits from a societal perspective, rather than transfers of wealth between producers and consumers. Discussion of this topic is beyond the scope of this white paper, but these issues should be considered in designing evaluation criteria.

purchases. As noted in Section 2.1, in order to meet objectives of counting Contracted Class I Tier purchases towards renewable energy goals and greenhouse gas targets, it is necessary that Connecticut establishes a unique claim to the renewable energy attributes of the purchases, by procuring the associated RECs.

The unique nature of the power generation and delivery system requires verification protocols and tracking systems so that policy-makers and consumers can be assured that the renewable attributes associated with RPS compliance are in fact being generated and delivered as envisioned. RPS compliance verification and tracking requirements implemented through the application of a tracking system creates a level playing field where all market participants are treated fairly.The NEPOOL GIS is the system that tracks Renewable Energy Certificates, the "currency" of renewable attributes, and is used by electricity suppliers to demonstrate compliance with the CT RPS. By tracking detailed information about each generator, the GIS verifies that claimed RECs are indeed coming from eligible generators, are delivered within the geographic and temporal requirements of the RPS programs, and are not "double counted," that is, not sold to more than one buyer or claimed by more than one recipient of attributes. All RPS compliance RECs are settled through the NEPOOL GIS.

The regional nature of the physical electric power system of New England, along with its ability to send and receive power between our region and other control areas including New York, Quebec, and the Canadian Maritimes, required special regulatory consideration. Each New England state's RPS rules and the GIS operating rules developed to support those state requirements explicitly require that generation sourced from outside of ISO-NE be clearly attributable to a specific generating resource.

The eligibility of renewable generating resources located outside of the ISO-NE control area and how that generation would be tracked was, and remains, one of the most complex and controversial components of the GIS system. The process of creating the GIS operating rules within the NEPOOL governance structure led to the development of two alternative approaches that address the issue of verifying and tracking imported power. Imported power can participate in the GIS in one of two ways:

1. Accounting for individual generation attributes separately from "system power" requires a unit-specific import transaction meeting a series of requirements detailed in the GIS rules. In this case, the imported power can carry resource-specific attributes to demonstrate RPS program eligibility and a unique claim or use; or

2. Verification and tracking by a compatible information system in an exporting control area to assign unit-specific specific attributes to any renewable energy import seeking RPS eligibility within ISO-NE.

   At such time as a source Control Area for Imported System Energy implements a generation information system that is compatible with the GIS, as determined by the NPC or its delegatee (a "Compatible GIS"), the NPC or its delegatee may amend this Rule 2.7(b) to address the creation of Certificates under this Rule 2.7(b). (New England Power Pool, 2013)

Because the treatment of imported power was likely the most hotly-contested aspect of the GIS operating rules during their development, and therefore would be very difficult to modify without substantial opposition from the NEPOOL members who reached the consensus reflected in the rules.

Neither Quebec nor the Maritimes have implemented compatible tracking systems. To our knowledge, Hydro Quebec has yet to suggest that it is interested in delivering unit-specific generation, preferring to deliver 'system power' from its system and simply call it hydroelectric. However, some of the components that make up Quebec's overall system power would not meet any specific ISO GIS eligibility requirements, and most would not meet the eligibility requirements recommended herein.

Recommendation:
In order to ensure that imported hydropower meets the policy objectives associated with creating a Contracted Class I Tier and that Connecticut can assert a unique claim, Connecticut should

1. Require any importing control area to have a compatible GIS, and seek the recognition of that system as a basis for granting source-specific RECs to imports under GIS Operating Rule Section 2.7; and
2. Require the purchasing entity to procure and retire the RECs associated with Contracted Class I Tier supply.

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Appendix A: Large-scale Hydro Supply to New England from Eastern Canada

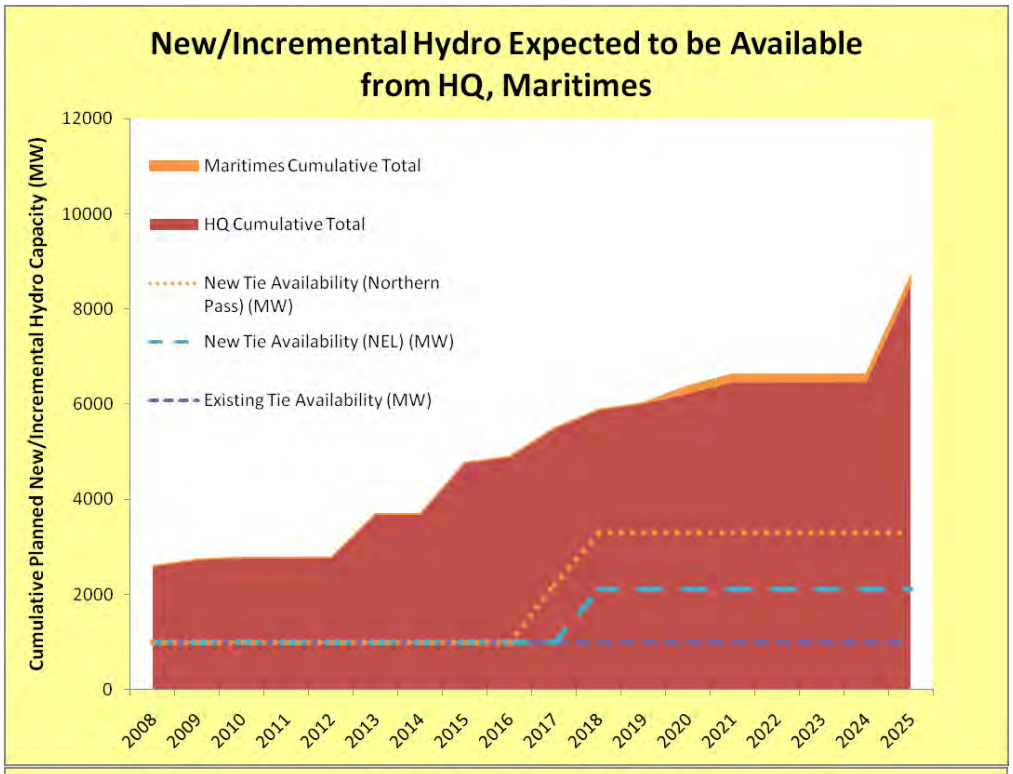
There is no shortage of large scale hydroelectric resources potentially available to New England that have been developed (or are planned for development) in the post-restructuring era. For purposes of assessing the potential minimum and maximum magnitude of procurement under the Contracted Class I Tier, we analyzed the potentially eligible large-scale hydro projects developed in Eastern Canada and the estimated timing of their commercial operation.

Under Current Geographic Eligibility (Adjacent Control Areas)

For purposes of this analysis, new hydro projects were considered that reached commercial operation after 1998, the eligibility threshold used by Massachusetts and Rhode Island for their Class I RPS programs. We also considered supply that would be eligible under current Connecticut RPS geographic eligibility rules and NEPOOL GIS requirements (New England Power Pool, 2013), which restrict RPS-eligible imports to adjacent control areas only.

Although Hydro Quebec has clearly been the most active player in market development to date, any resource from New York or the Canadian Maritime provinces (New Brunswick, Nova Scotia, Prince Edward Island) would also be eligible. Realistically, these alternatives will have little impact, if any, on the market for imported new hydro supply. New York has substantial operating hydroelectric resources, but the supply sources online prior to 2003 are already being counted towards New York's 30% renewable energy goal as part of its renewable energy baseline (New York Public Service Commission, 2004), and therefore such resources would fail any additionality requirement. We expect New York's own aggressive RPS requirements will absorb the majority of any incremental hydro capacity. The Maritimes control area is not expected to see extensive development in the foreseeable future. There are negligible hydro resources in PEI, no development plans for Nova Scotia, and only one hypothetical project proposed for New Brunswick (a 50-150 MW expansion of the Grand Falls dam).

Figure 12 depicts the scale and timing of the maximum potential capacity expected from these resources in aggregate. Figure 12 (top) illustrates this trend in cumulative terms, while Figure 12 (bottom) breaks the resources into arbitrary size classes, should Connecticut want to consider restricting contracting supply to plants below a specified capacity cap. Overlaid on the graph is the approximate scale of available capacity to import over (a) existing HVDC ties to Quebec, (b) a new 1200 MW Northern Pass tie to Quebec (assumed energized no earlier than 2017), and (c) a 1,100 MW Northeast Energy Link connection to the Maritimes (assumed energized in 2018). What the figures demonstrate is that the available generation capacity greatly exceeds the available transfer capacity, even assuming substantial transmission expansion. The corresponding information is depicted in energy terms in Figure 13, assuming an average capacity factor of 63% (Coste, 2010) and estimated line losses of 8%.



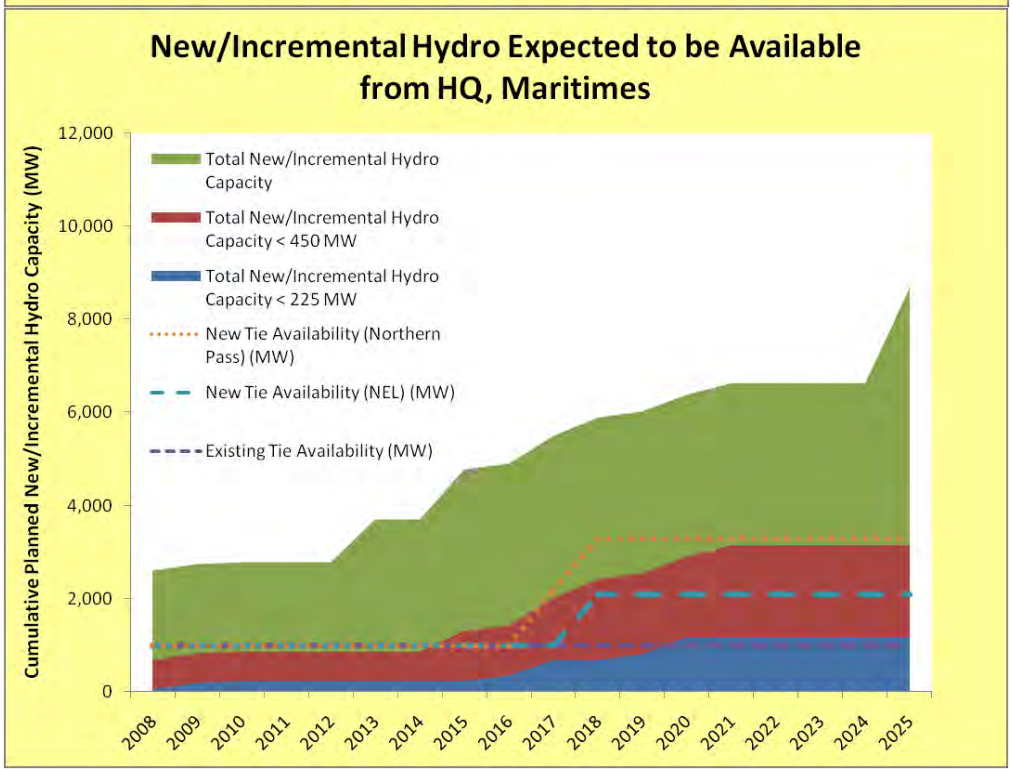


Figure 12. New/Incremental Hydro Resources from Adjacent Control Areas

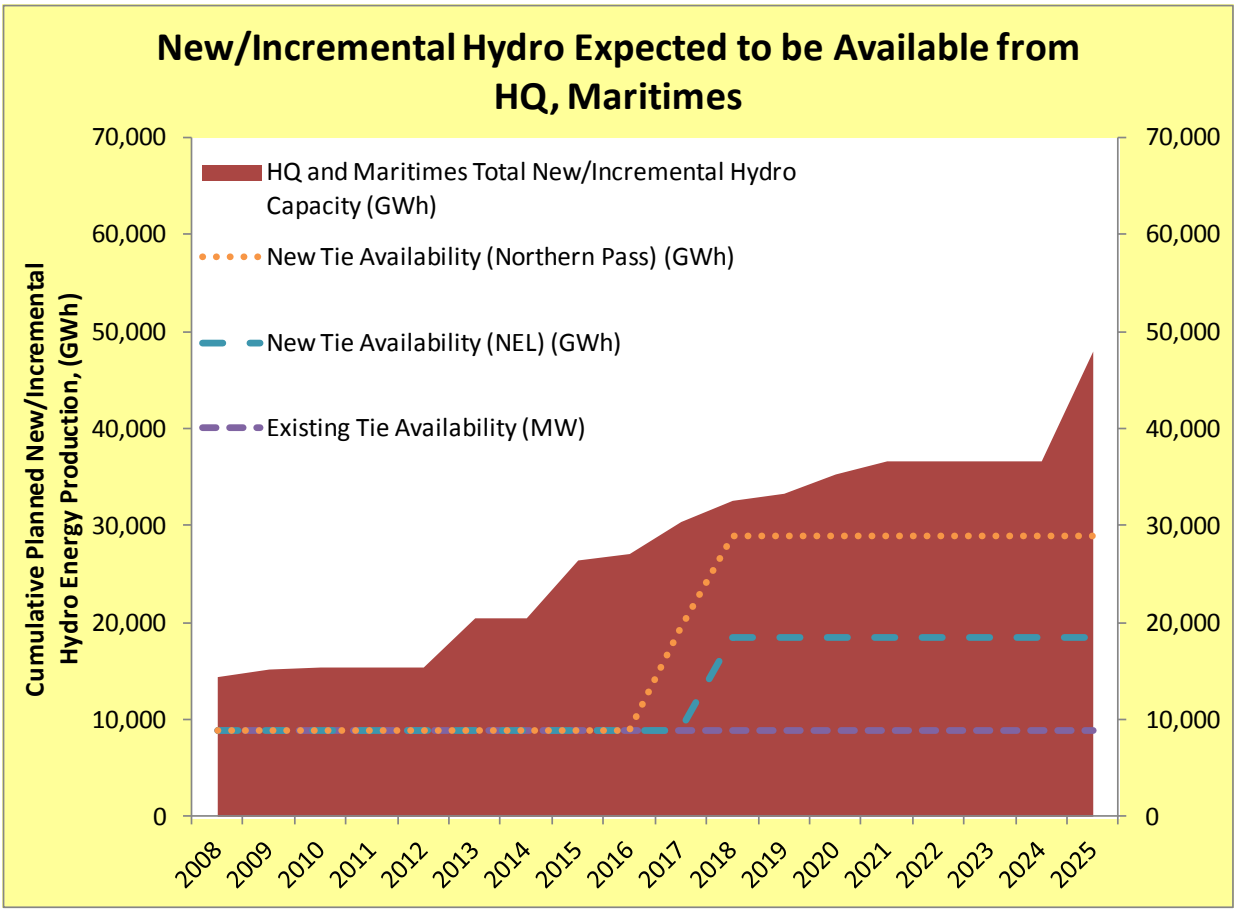


Figure 13: Energy Available from New/Incremental Hydro from Adjacent Control Areas

Under Expanded Geographic Eligibility

A second issue that warrants consideration is the potential relaxation of geographic eligibility requirements to generation from beyond adjacent control areas. Nalcor, the provincial energy company for Newfoundland and Labrador, has made it clear in its future development plans that they are looking to New England and other regional markets for export opportunities for their planned hydroelectric developments at Muskrat Falls and Gull Island, collectively referred to as the Lower Churchill Falls projects (See Figure 14). Allowing these generators to participate in New England markets would increase competition and thereby might reduce prices to Connecticut for the Contracted Class I Tier supply. Expanding the potential supply (and number of competitors) to meet the Contracted Class I Tier supply would require statutory change to alter the current geographic eligibility area, as well as changes to the NEPOOL GIS imports rules (which may meet substantial resistance particularly if drawn broadly). Resources from Ontario might also be considered as part of this analysis.

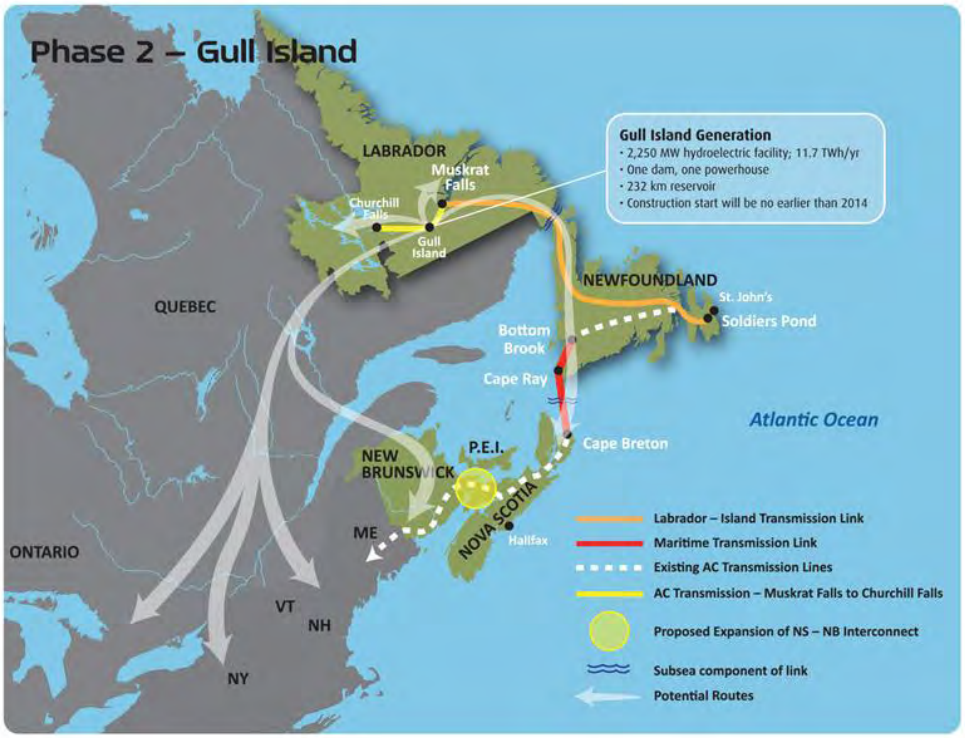
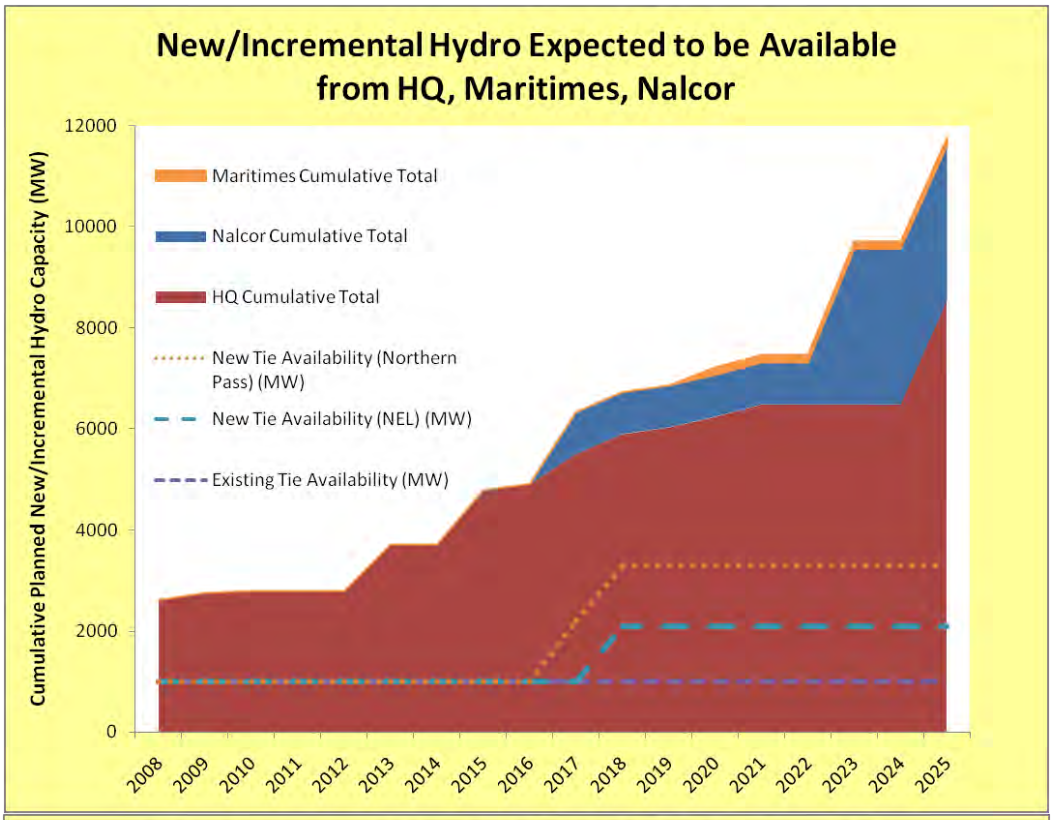


Figure 14. Nalcor Capacity Expansion and Export Plans for Lower Churchill Projects (Nalcor Energy)

Should Connecticut and NEPOOL GIS change their geographic eligibility requirements to allow this supply to enter the market, the regional supply outlook is expected to look more like Figure 15. Again, Figure 15 (top) illustrates the growth in cumulative terms, while Figure 15 (bottom) groups the resources into size classes. Still the available transmission capacity serves as a binding constraint to accessing the total large-scale hydro available supply.

The timing of completion of transmission necessary to make supply from these Lower Churchill projects available to New England is uncertain. Several additional transmission links within Canada would be required (Nalcor Energy), including the Labrador-Island Transmission Link (Newfoundland Labrador Department of Environment and Conservation) and the Maritimes Link (Emera), as well as transmission within New England to relieve North-south transmission constraints currently limiting delivery of energy from both imports from the Maritimes and generation from northern Maine. The timeline for the Maritimes Link is identified by Emera as 2017, but due to the multiple contingencies and propensity for complex transmission system project timelines to slip, the transmission component could delay availability of this supply beyond 2017.



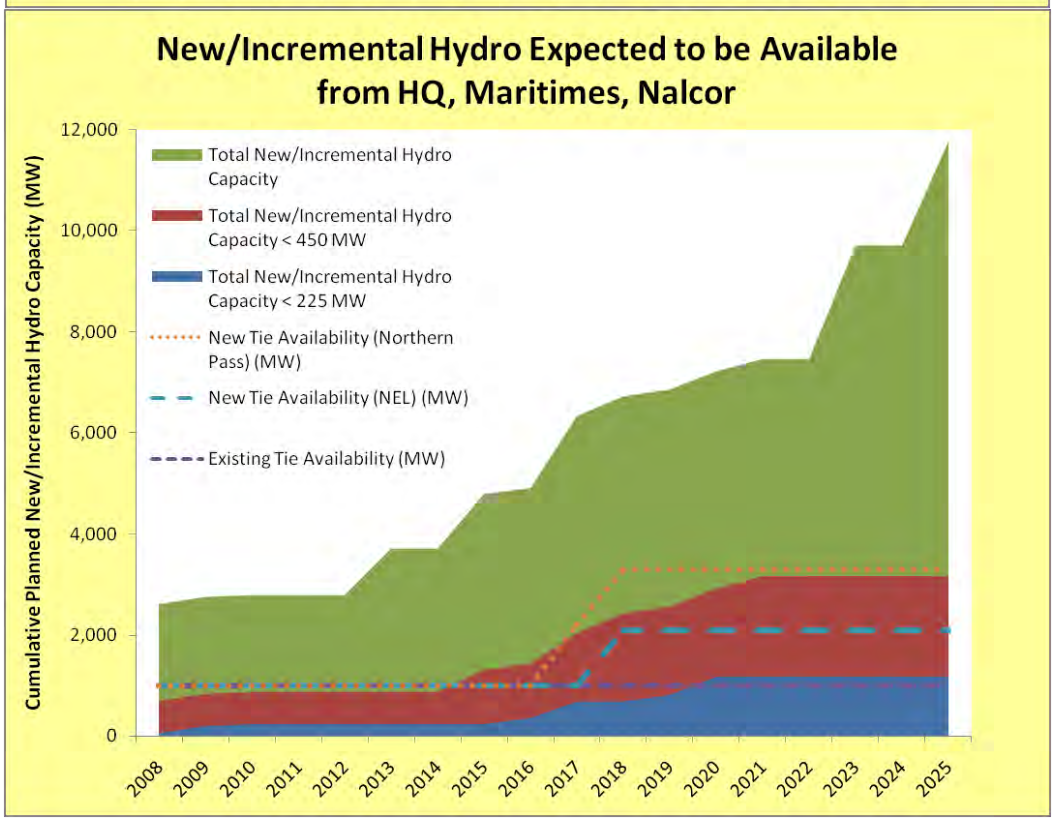


Figure 15. New/Incremental Hydro Resources from All Accessible Control Areas

The corresponding information is depicted in energy terms in Figure 16, assuming an average capacity factor of 63% and estimated line losses of 8%.

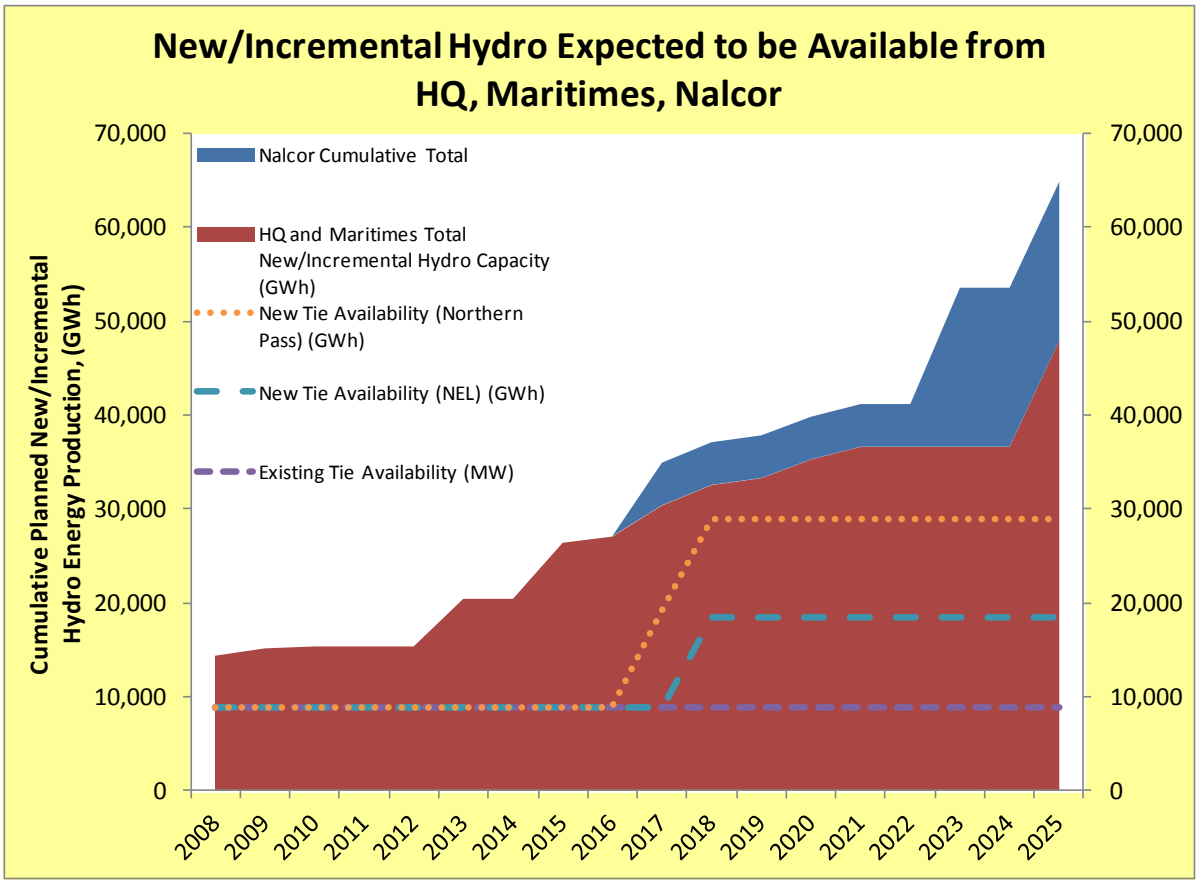


Figure 16. Energy Available from New/Incremental Hydro from All Service Areas

Appendix B: Preliminary RPS Scenarios

A number of possibilities were considered when deciding which scenarios to select for modeling. Table 11 outlines these issues and the range of possibilities considered. Each factor affects the shape and timing of a Contracted Class I Tier in different ways. Therefore, alternatives for each factor were combined to create a total of nine preliminary scenarios, covering a range of possible market futures.

Table 11: Factors Influencing Timing and Scale of Contracted Class I Tier

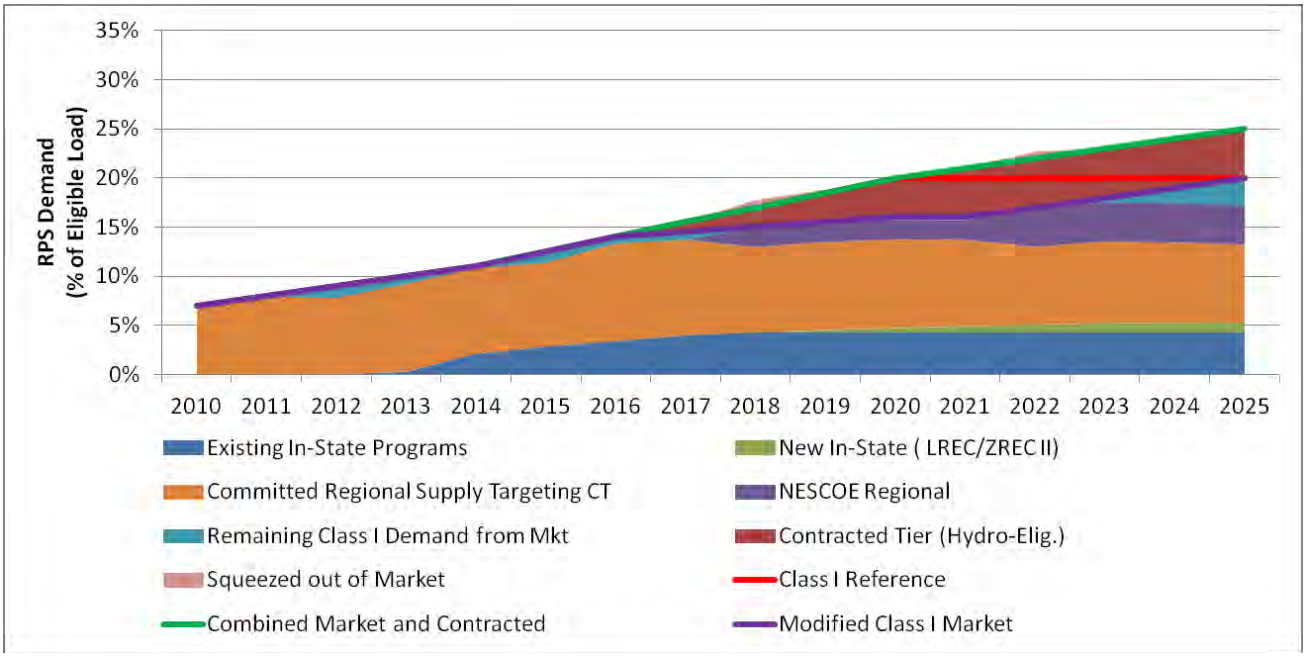
Dimension	Earliest or timing constraint	Shape (ramp up, block, laddered blocks)	Ultimate Scale Range
Combined Targets	n/a	Options of simple extension, accelerated ramp up and block-wise progression	(reference)20x25 25% by 2025 High: 50x25 (allowing for 1,000 MW of contracted hydro)
Market Class I Target	Earliest changes in 2016 or later to allow for market adjustment, and recognize FCA commitments based on current policy	Most scenarios slow growth or carve out obligation to end at 10-20% in 2025 (compared to baseline of 20% in 2020)	Low: 10% (Scenario 4) Mid: 15% (Scenario 2, 5) High: 20% (Scenario 1, 3, 6)
Contracted Target	Small quantities enter in 2015 or 2017, large must wait for Tx expansion in 2017/18	Options of smooth ramp up or block-wise progression	Low: 5% (Scenario 1) Mid: 10% (Scenario 2, 3) High: 20% (Scenario 4, 5) Max: 30% (Scenario 6)
NESCOE Regional Procurement	Early-mid-2017 (est. of earliest possible deliveries consistent with analysis of NESCOE workplan); or 2020 (appearance of potential gap)	1, 2 or 4% blocks, which can be single or additive	at least 1% blocks (at a material scale, at least 1 year increments)
New In-state policies (LREC/ZREC-II)	2019 (after PA 11-80 policies phase-in complete)	Ramp up to 0.5, 1 or 2% total commitment by 2025	Low: 0.5% (Scenario 2) Mid: 1% (Scenario 1, 4, 5) High: 2% (Scenario 3, 6)

Table 12 details each of these preliminary scenarios, which were then combined and narrowed down to the final four options presented in Chapter 5 (not including the conditional flexibility option described in Section 5.5). Illustrations for each scenario are also included below.

Table 12: Preliminary Contracted Class I Tier Scenarios Examined

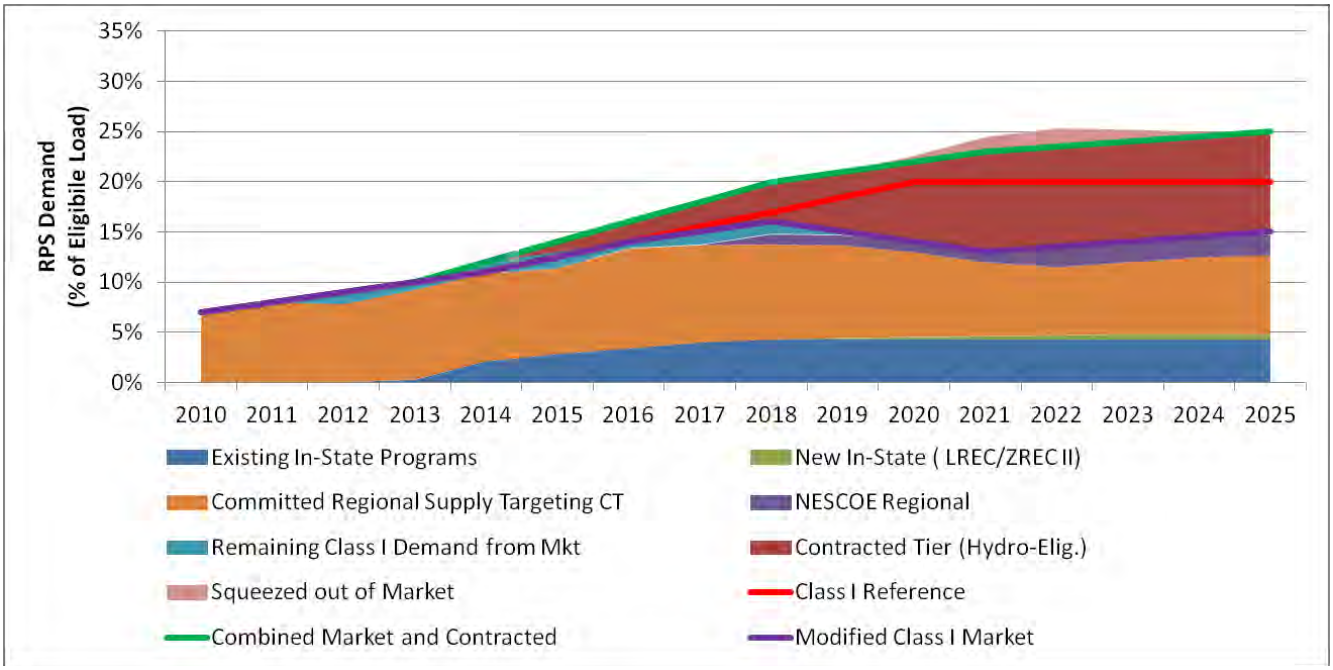
Case	Combined Targets (Market and Contracted Tier)			Market Class I Tier			Contracted (Hydro Eligible) Tier			NESCOE Regional	New In-state policies (LREC/ ZREC-II)
	2015	2020	2025	2015	2020	2025	2015	2020	2025		
Reference	12.5%	20%	20%	12.5%	20%	20%	0%	0%	0%	None	None
Scenario A (25x25 Extension)	12.5%	20%	25%	12.5%	16%	20%	0%	4%	5%	2%/4% Blocks in 2018/2022	2019-2024 Ramp to 1%
Scenario B (25x25 Accelerated)	14%	22%	25%	12.5%	14%	15%	1%	8%	10%	1%/2% Blocks in 2018/2022	2019-2023 Ramp to 0.5%
Scenario C (30x25, 10% Hydro)	14%	23%	30%	12.5%	15%	20%	1%	8%	10%	2%/4% Blocks in 2018/2022	2019-2025 Ramp to 2%
Scenario D (30x25, 20% Hydro)	14%	23%	30%	12.5%	10.5%	10%	0%	12.5%	20%	1%/2% Blocks in 2018/2022	2019-2024 Ramp to 1%
Scenario E (35x25, 20% Hydro)	15%	25%	35%	12.5%	12.5%	15%	0%	12.5%	20%	1%/2% Blocks in 2018/2022	2019-2024 Ramp to 1%
Scenario F (50x25, 30% Hydro)	15%	30%	40%	10%	20%	20%	5%	10%	30%	2%/4% Blocks in 2018/2022	2019-2025 Ramp to 2%
Scenario G (20x20, 5% Hydro)	12.5%	20%	20%	11.5%	15%	15%	1%	5%	5%	1%/2% Blocks in 2018/2022	2019-2024 Ramp to 1%
Scenario H (20x20, 10% Hydro)	12.5%	20%	20%	12.5%	15%	10%	0%	5%	10%	1%/2% Blocks in 2018/2022	2019-2024 Ramp to 1%
Scenario I (20x20, 20% Hydro)	12.5%	20%	20%	12.5%	7.5%	0%	0%	12.5%	20%	None	None

Figure 17: Scenario A



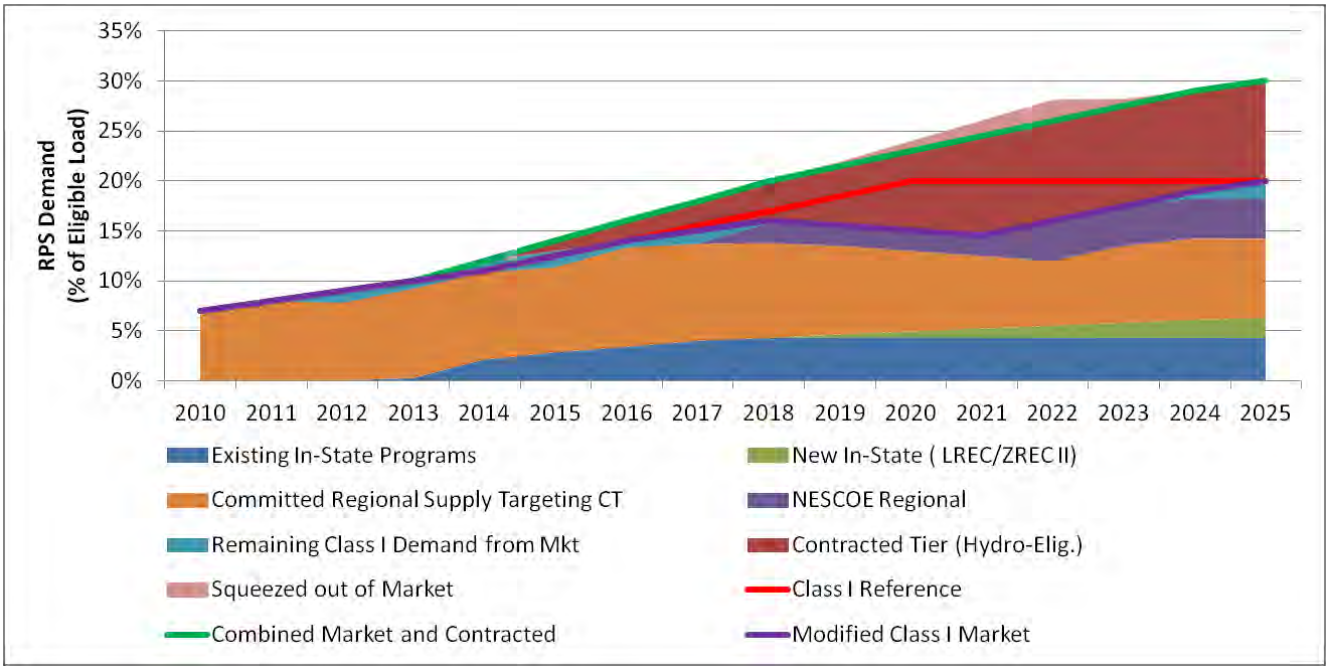
Scenario A extends the current RPS structure beyond 2020 to reach a new combined target of 25% in 2025, including a new 5% Contracted Tier that ramps up starting in 2017 before reaching 5% in 2021. This approach carves a portion of the current targets out of the Market Class I Tier starting in 2017. This puts downward pressure on demand from the regional REC market and shifts the need for additional regional supply out to after 2022. The shift away from the regional market (and subsequent ACP risk) in this scenario results from an assumption that Connecticut participates in two NESCOE regionally coordinated procurements—one in 2018 and another in 2022 (purple layer)—as well as incremental in-state programs (green layer) totaling 1% of eligible load by 2024. Under this scenario, virtually no existing or committed supply is pushed out of the Connecticut market.

Figure 18: Scenario B



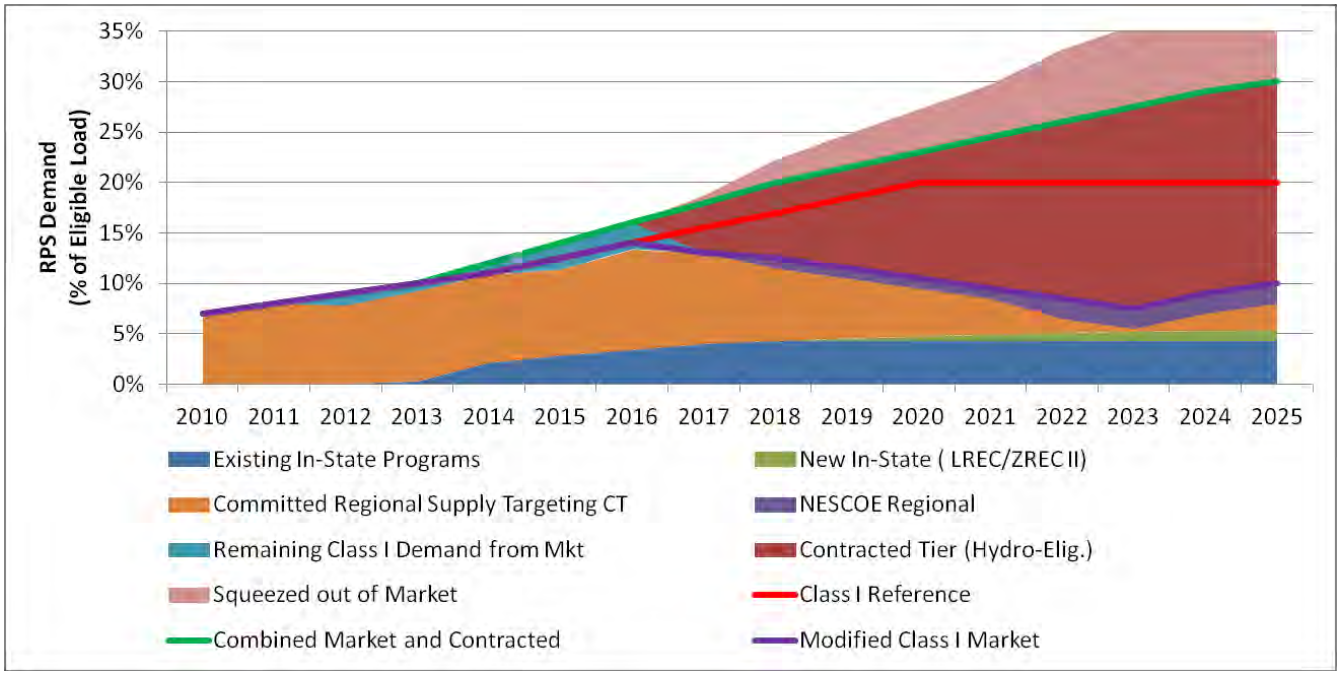
Scenario B illustrates the combination of a 25% by 2025 combined target with a larger Contracted Tier. A 10% hydro-eligible tier is introduced in 2015 and scales up to reach 10% of load by 2021. This scenario presumes that Connecticut participates in two NESCOE regionally coordinated procurements (in 2018 and 2022), each consisting of 1% of load (purple layer), as well as a modest set of incremental in-state programs (green layer) totaling 0.5% of load. The combination of these changes results in limited market exposure through 2019 and none thereafter. Because the Contracted Class I tier increases at a greater rate than the combined target, the Market Class I Tier shrinks after 2018, displacing supply to be met by the market, but also pushing a modest amount of existing or committed supply (rose layer) out of the market beginning in 2020. Under this scenario, the total Class I Market obligation is 15% in 2025 rather than 20% by 2020, a reduction (and presumed cost savings) compared to the reference case.

Figure 19: Scenario C



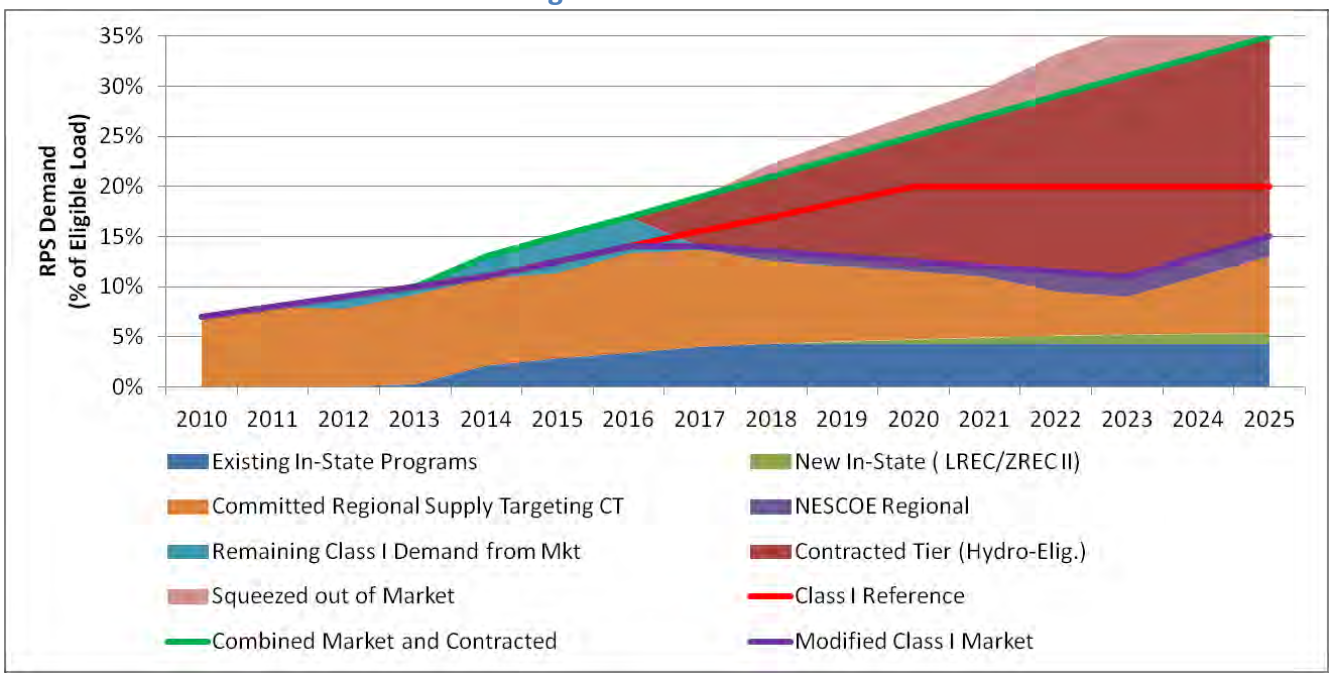
As illustrated, Scenario C is very similar to Scenario B, but with a higher combined target of 30% by 2025. Ramping up to a 10% Contracted Tier between 2015 and 2021, this scenario achieves a final target of 30% in 2025 without exposing Connecticut to significant market risk. This is achieved through more aggressive Connecticut participation in NESCOE regionally coordinated procurement (purple layer) and incremental in-state procurements (green layer), totaling 4% and 2% respectively. Again, a small amount of existing and committed supply (rose layer) would be pushed out of the Connecticut market, potentially towards other states in the region.

Figure 20: Scenario D



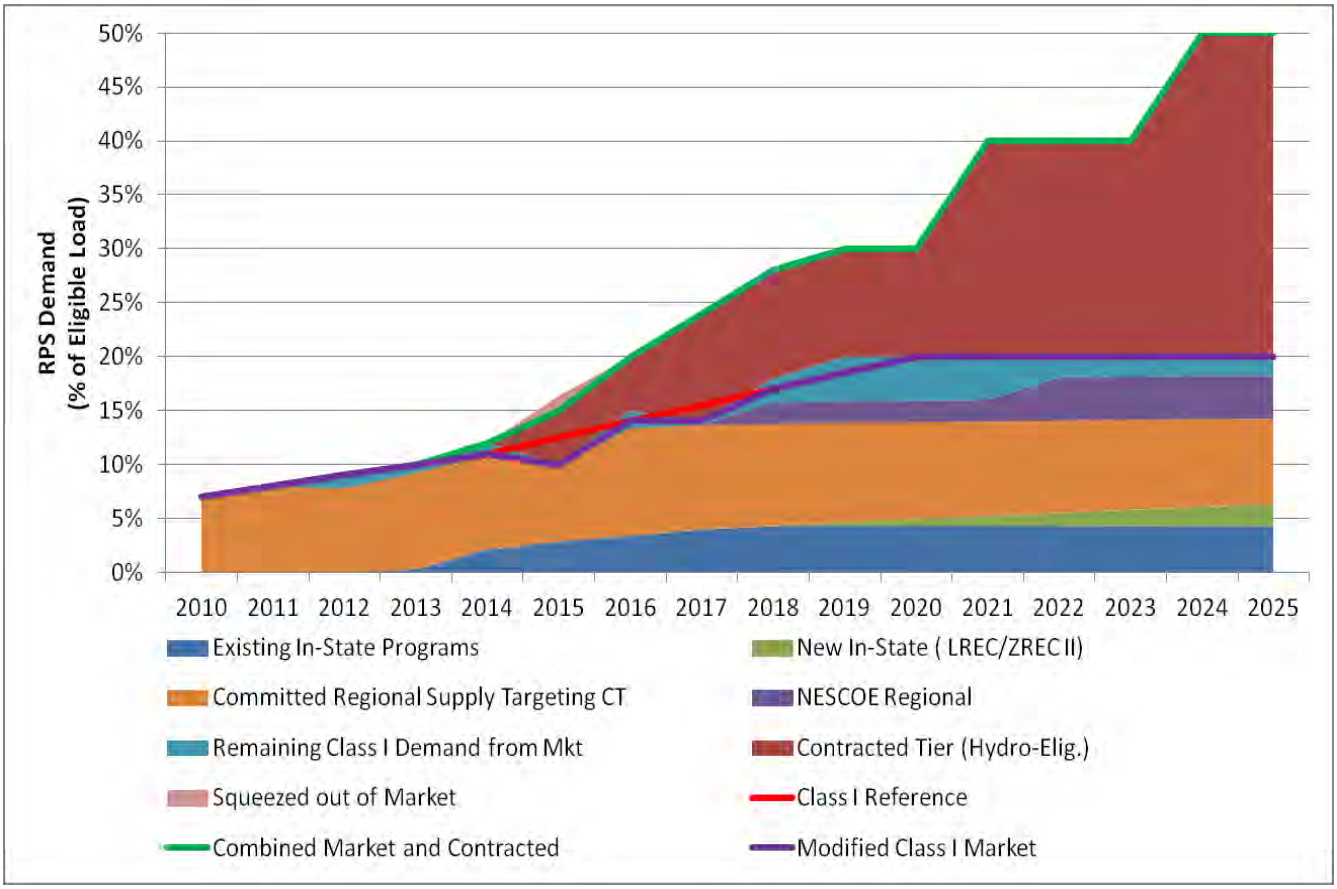
Scenario D illustrates the effect of a very large Contracted Class I Tier procurement (on the order of 700 MW) within a combined Class I target reaching 30% of load by 2025. The new Contracted Class I Tier phases in to reach 20% of load by 2023, with the Market Class shrinking to 10% by 2025. It presumes less Connecticut participation in NESCOE coordinated regional procurement (purple layer), as well as a modest set of incremental in-state programs (green layer). This scenario consequently squeezes out the existing and committed renewable supply that currently targets the Connecticut Class I market (orange layer); the total contribution of the orange layer shrinks to almost 0% in 2023, with significant supply squeezed out of the market (rose layer). Despite these drawbacks, this scenario illustrates a case of very low market risk and likely cost savings from a final Class I Market target equivalent to only 10% of eligible load, but in effect abandons the Market Class I RPS policy going forward after 2016, including a retreat from levels reached prior to that date.

Figure 21: Scenario E



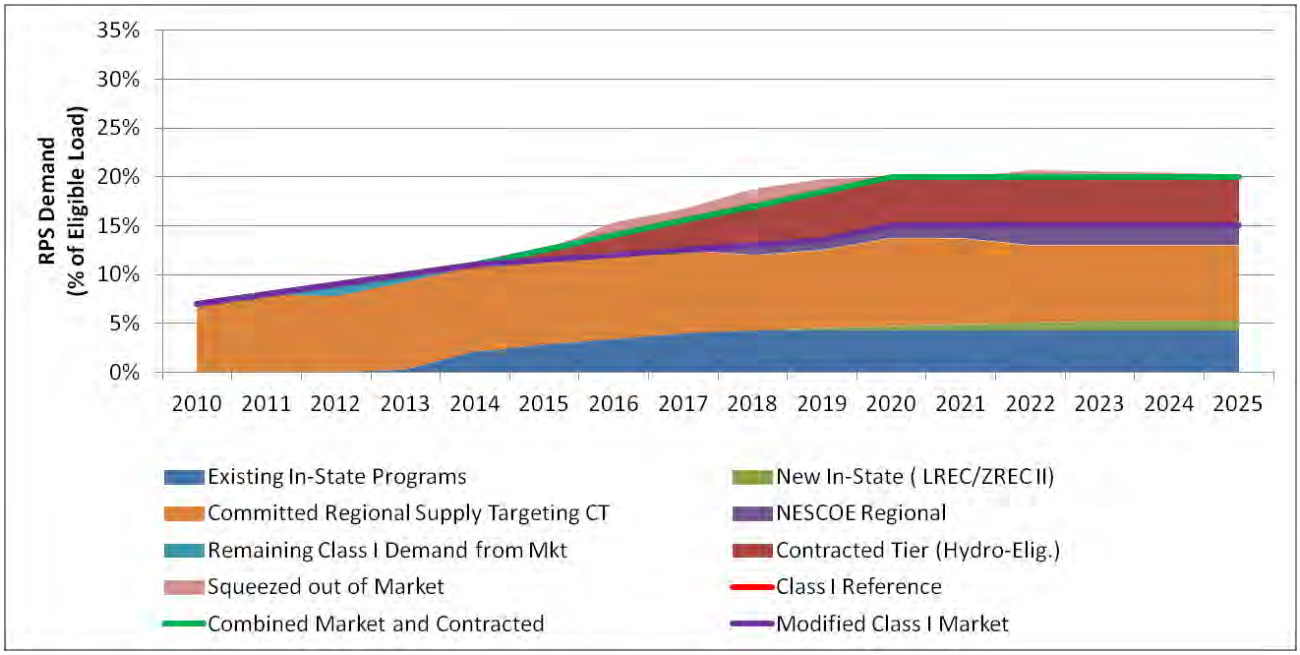
Scenario E is nearly the same as Scenario D, but with a final combined target of 35% of load by 2025. The difference between these two scenarios is that in this scenario, the Market Class I Tier is allowed to reach 15% by 2025, rather than 10%, with a smaller quantity of existing or committed supply (rose layer) squeezed out of the market. If Connecticut chooses to pursue a large-scale hydro contract under the Contracted Class I tier - on the order of 700 to 1000 MW - it may want to consider a very aggressive combined RPS target. Scenario E illustrates the impact of limiting ratepayer market exposure, accelerating targets as part of a broader greenhouse gas reduction push, reducing the final Class I market target from 20% in 2020 to 15% in 2025, while protecting some (but not all) of the existing and committed supply that currently targets the Class I RPS.

Figure 22: Scenario F



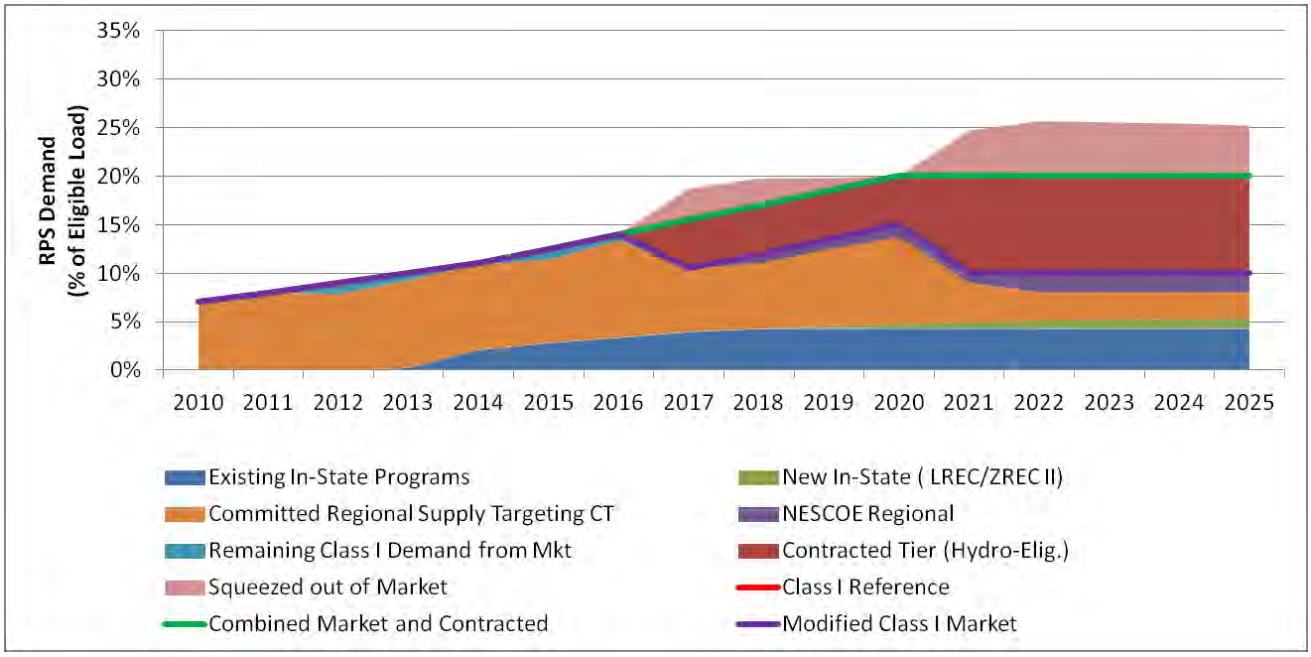
Scenario F simulates the most aggressive combination, with combined targets reaching 50% by 2025. It presumes that current Market Class I targets are maintained at 20% by 2020 in the long-run (although modestly decreased between 2015 and 2017), with a large Contracted Class I Tier phasing up to 30% by 2025, corresponding with a series of large-scale hydro contracts totaling roughly 1000 MW. It assumes Connecticut participation in NESCOE coordinated regional procurement (purple layer) stepping up to 4% of load, combined with incremental in-state programs ramping up to an additional 2% of load by 225. This approach, which represents an extremely aggressive approach to decarbonizing Connecticut's electricity use, would not reduce Connecticut's existing RPS commitments and spare the existing and committed supply. While this scenario does not reduce ratepayer costs materially (except during the 2015-2017 timeframe), it does seek a much greater role for renewables without a material cost increase from the status quo.

Figure 23: Scenario G



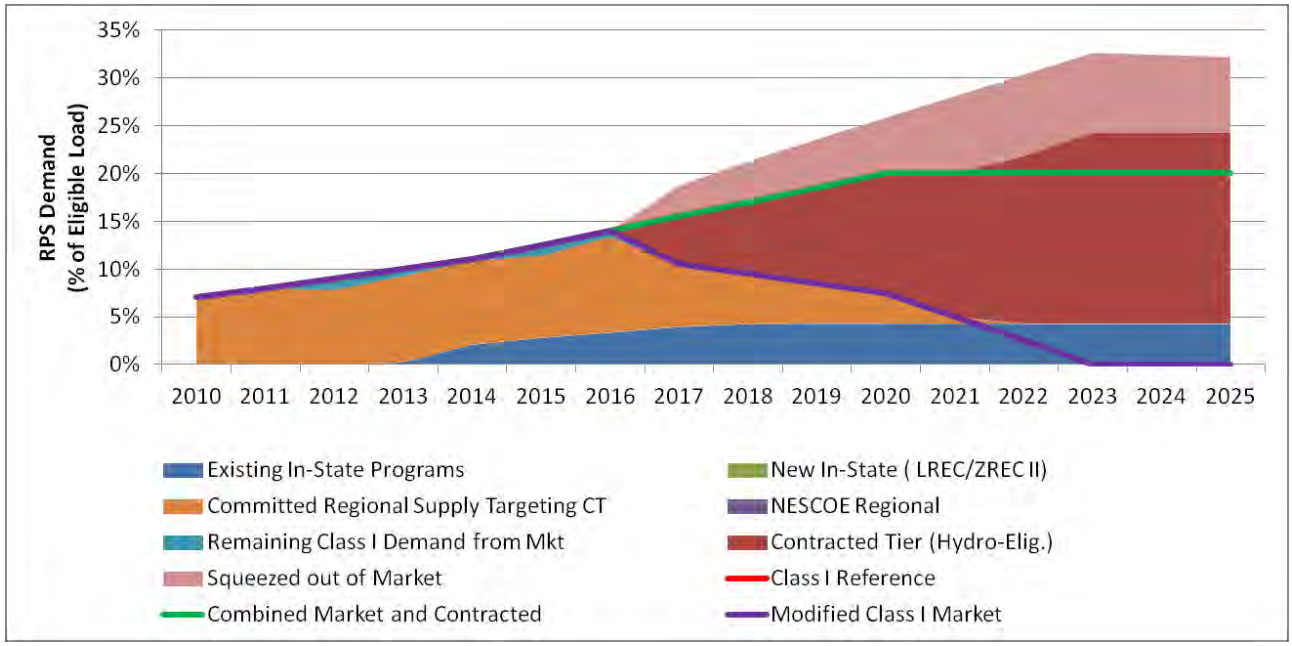
Scenario G represents a situation in which the current RPS target is not increased at all, but rather a Contracted Class I Tier is carved entirely out of the current RPS targets of 20% of load by 2020. It assumes Connecticut participation in NESCOE coordinated regional procurement (purple layer) stepping up to 2% of load, combined with incremental in-state programs (green layer) ramping up to an additional 0.5% of load. Under this scenario, the Contracted Class I Tier would commence in 2015 and phase up to 5% of load by 2020, with the Market Class I target capped at 15% by 2020. . The combination of characteristics of this scenario result in negligible market exposure for ratepayers, the reduction of the Class I Market goal to 15%, and a modest quantity of existing and committed supply (rose layer) being pushed out of the market. For context, a 5% contract under the new tier is equivalent to 180 average MW (aMW).

Figure 24: Scenario H



Scenario H, like Scenario G, maintains the combined targets at the level of the current class I RPS targets, and carves a Contracted Class I Tier entirely out of these targets. It assumes the same assumptions as Scenario G for Connecticut participation in NESCOE coordinated regional procurement (purple layer) and modest incremental in-state programs (green layer). In this scenario, however, the Contracted Class I Tier ramps up to 10% of load, leaving the Market Class I Tier reduced to only 10% of load, a level already reached as of this year. This Contracted Class I Tier is comparable to 360 aMW, and results in a significant quantity of existing and committed supply (orange layer) being pushed out of the market (rose layer). Ratepayer risk exposure to market shortage and ACP-based pricing under this scenario is very low, but at the expense of Connecticut effectively bailing out of the New England Class I Market other than the modest regional procurement.

Figure 25: Scenario I



Scenario I illustrates the impact of a very large Contracted Class I Tier, ramping up to 20% of load, being forced under the existing target of 20% by 2020. Under this scenario – corresponding to a Contracted Class I PPA total of about 720 aMW – the Contracted Class I Tier eventually fills the entire Class I RPS target. As a result, all of the existing and committed supply (orange slice) is pushed out of the market by 2021. Assuming the existing LREC, ZREC and other state contracts will still be honored (and therefore the projects would continue to operate for the life of their PPAs, this approach would result in total supply above the target and to 25% by 2025.