CONSULTANT REPORT

Value of Renewable Export Attributes to Hydro Québec

Prepared for: Association québécoise de la production d'énergie renouvelable

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La Capra Associates

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EXHIBITS

1. INTRODUCTION

In Application R-3864-2013, Hydro Québec Distribution ("HQD") filed their supply plan (or more generally, resource plan) for the 2014-2023 time period. The supply plan reviews HQD's forecasted energy and capacity needs in terms of Québec's internal demands from various consumer groups or sectors. These requirement forecasts are then compared to various sources of supply including energy efficiency and demand response, patrimonial hydro supply, and post-patrimonial supply contracts.

This last category features long-term contracts with renewable supply sources (wind, biomass, and small hydro) that produce energy, capacity, and environmental attributes. Each of these products can be used by HQD to meet their demand requirements or can be sold to generate revenue and thereby reduce the costs of these contracts to ratepayers. The focus of this report is on the provision and sale of environmental attributes.

HQD expends less than one page of their supply plan discussing the sale of environmental attributes. In that page, HQD mentions the view espoused in the 2011-2020 supply plan that sale of these attributes in the United States ("U.S.") was not a realistic or promising option and that this view will be carried over to the current supply plan. Though the explanations for this view are sparse, HQD does mention that the U.S. attribute markets are mostly concerned with local development[1] and that deliveries of power, and by implication transmission availability, would be required (especially to New England). As an alternative, HQD mentions the possibility of sale of attributes to "voluntary" markets, and proposes to participate in these markets with focus on the certification of the wind parks in the EcoLogo program.

In this report, I discuss the possibility and benefits of HQD selling environmental attributes into U.S. renewable markets, with special emphasis on New England. As a result of my research and analysis, I provide the following conclusions or findings:

- Revenue streams beyond energy and capacity from renewable projects currently in its portfolio (and in the future) are possible through deliveries to New England.
- The process to apply and qualify to sell environmental attributes is not onerous and would be most beneficial if initiated as soon as possible.
- Additional revenue streams from sale of environmental attributes can be substantial and can lead to significant revenues to HQD (and savings to ratepayers)

The Association Québécoise de la production d'énergie renouvelable ("AQPER") retained La Capra Associates, Inc. ("La Capra Associates") to provide this report. La Capra Associates is an employee-owned consulting firm which has specialized in the electric and natural gas industries for more than 30years. The firm's expertise includes power market policy and analysis (wholesale, retail, and renewable), power procurement, power resources planning, economic/financial analysis of energy assets and contracts, and regulatory policy. La Capra Associates has been involved in many aspects of

[1] While local development is certainly a goal, most New England states allow (and require) that most of their renewable purchases come out of the state, which creates minimal economic development to the ratepayers that are bearing the costs of these purchases.

the renewable energy sector over the past decade. As a firm, La Capra Associates has conducted a number of renewable resource potential and economic impact analyses for various states (Massachusetts, New York, North Carolina, Connecticut, South Carolina, and Arkansas). In particular, La Capra Associates provided analyses and assistance to state policymakers during development of the Massachusetts renewable portfolio standards ("RPS") and examined the costs and benefits of the RPS in North Carolina. The company also has power markets modeling expertise, especially in the Northeast and Mid-Atlantic regions of the U.S, including modeling of Canadian imports.

La Capra Associates analyzes renewable energy certificate markets, by developing an understanding of project economics and tracking of proposed projects and RPS regulations. Furthermore, the firm provides transaction advice, financial modeling and asset valuation support to private and government entities seeking to sell renewable output and certificates and engage in purchases of renewable energy, including through long-term PPAs. The firm has extensive experience in regulatory proceedings involving analysis of power purchase agreements and utility investment in renewable energy projects. La Capra Associates staff has provided testimony in a number of regulatory proceedings in the Northeast, including review of solar as a non-transmission alternative to the Maine Power Reliability Project and evaluation of the proposals of National Grid and Western Massachusetts Electric to purchase and install

EXPERT/CONSULTANT:Alvaro E. Pereira, Ph.D.

Alvaro E. Pereira, Ph.D., a Managing Consultant at La Capra Associates, plays a major role in the firm's activities in the renewable energy sector. He has extensive familiarity with project development and market issues in the Northeast U .S. and has conducted and examined a number of market forecasts, including energy, capacity, and reserve markets, for use in renewable project analyses. Dr. Pereira recently assisted with the analysis of the New York RPS and led cost-benefit analyses of solar and offshore wind development in Massachusetts and New York. He has hands-on experience with power markets modeling, financial modeling, and power project economics and cost-benefit analyses. For private clients, Dr. Pereira provides advisory services related to power and REC procurement and the feasibility of signing long-term PPAs. Prior to joining La Capra Associates, Dr. Pereira was at the Massachusetts Division of Energy Resources, which serves as the regulator for the Massachusetts RPS, for nearly nine years as the head of a group responsible for economic and technical analyses of policies, programs, and regulatory filings. He also served as Senior Lecturer at the Massachusetts Institute of Technology where he taught graduate-level courses on Regional Economic Impact Analysis and Transportation Economics. Dr. Pereira received his doctorate degree in regional economics at the Massachusetts Institute of Technology. His full resume can be found in **Appendix A**.

solar facilities throughout their service territories in Massachusetts.

2. CONVENTIONAL VS. GREEN ENERGY

A comparison of the various "products" underlying conventional and renewable energy is useful as background. The term "conventional" is used here to signify generation types that historically have been used for meeting the great majority of energy demands. In the U.S., this generation has consisted of coal, oil, and more recently, natural gas, while in Québec, the predominant generation source has been large hydro[2]. By contrast, "green" energy will be used to signify energy produced from sources that have been determined or defined by certain jurisdictions to be renewable or featuring limited or no negative environmental impacts. As expected, the definition of what is considered "green" can vary from region to region, depending on the policy environment of each region and the underlying reasons to support green energy, such as environmental benefits, local economic development, and development of indigenous resources.

2.1 CONVENTIONAL ENERGY REVENUE STREAMS/PRODUCTS

Conventional energy generation products[3] can be used to meet a utility's internal demands and requirements in serving its customers or, where applicable, can be sold to other utilities or market participants. The specific "products" available for sale are determined by the particulars of the market or region of interest and are regulated by federal or national agencies where interstate sales or sales for resale occur. In this section, I concentrate on the wholesale electricity markets and products sold and bought in New England, which are quite similar to the markets in New York and in PJM[4] and show some similarities with other parts of the United States (such as the Midwest ISO).

Though a greater level of detail is possible, generation products can be broken into three major components: energy, capacity, and ancillary services. The first two are commonly featured and discussed in resource planning efforts and can be found in HQD's supply plan (see Tables 4-1 and 4-2 on pages 27 and 28 of the plan, for example). The figure below shows estimates of these revenues by

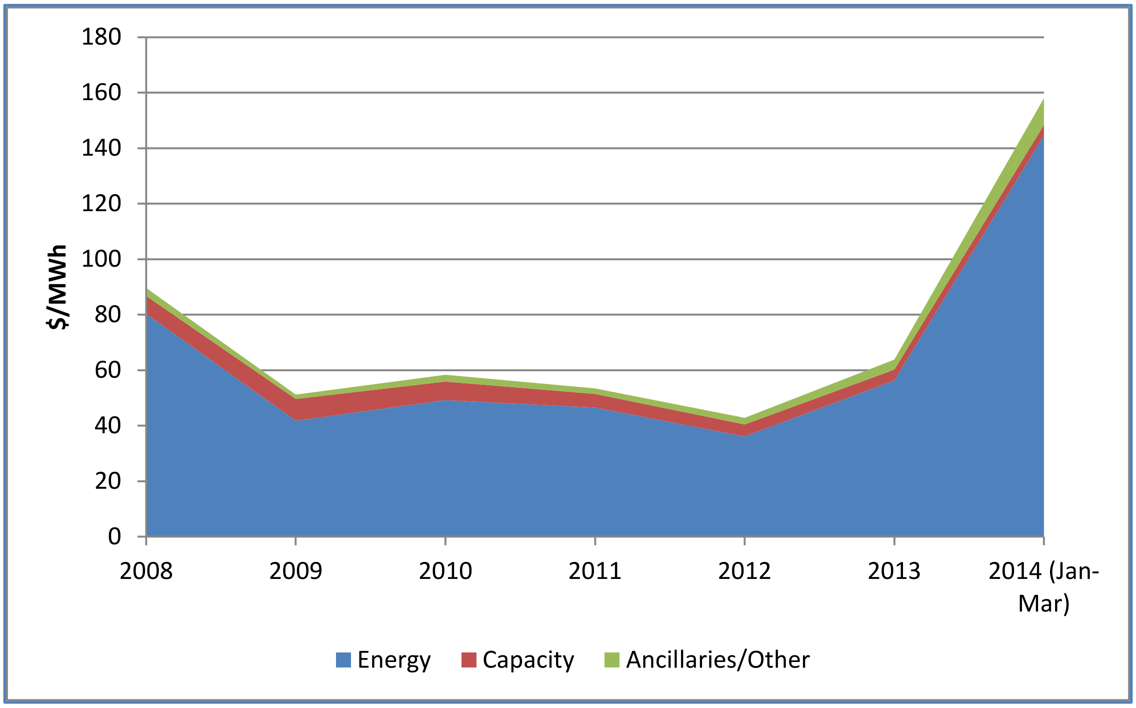
[2] The distinction between large and small hydro is not universally defined, but small hydro can be considered as facilities with capacities of 10 MW or less. This upper limit can be as high as 30 MW, depending on the region or jurisdiction. Hydro Québec has 9 generation stations with nameplate of less than 30 MW as part of their over 33,000 MW system (as of December 31, 2012), indicating the dominance of large hydro facilities.

[3] The primary physical products are generation of energy over time (in terms of kilowatthours or megawatthours) and generation of energy during peak conditions (in terms of kilowatts or megawatts at a particular point in time), commonly referred to as "capacity".

[4] PJM is North America's largest independent system operator ("ISO") and encompasses all or parts of states in the U.S.: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

using the costs paid by load[5] for each of these components over the past 6+ years as a proxy. Data are shown for delivery to Northeast Massachusetts/Boston, but the data are similar for other zones in New England.

FIGURE 1. AVERAGE ANNUAL WHOLESALE LOAD COST, BOSTON[6]



Conventional resources generally qualify and receive energy and capacity revenues, but some might not elect or be able to receive revenues from ancillary service markets or products due to delivery and product requirements and opportunity costs. The figure shows that energy costs (and revenues) comprise the majority of wholesale costs. The figure also shows the impact of natural gas prices on electric prices with the decline and low prices in 2009-2012 reflecting the lower prices due to the advent of shale discoveries in western Pennsylvania. The steep increases in 2013 and especially earlier this year signify the increase in natural gas demands coupled with the inability of natural gas infrastructure to deliver gas to New England. This increase in potential energy-market revenues makes the export of power from Québec (and elsewhere) attractive.

These revenue streams are used to pay for the costs to construct and operate conventional generation sources. These costs include both fixed and variable (including fuel) costs. During the 2009-2013

[5] Costs paid by load include components, such as ISO administration fees, that do not provide revenues to resources, but such components are a relatively minor (< $1/MWh) component of costs. As such, use of these numbers is approximate but still informative.

[6] Source: ISO-NE. Data are averaged over all hours.

period, the total amount of these revenues averaged close to or below $60/Megawatthour ("MWh"). This amount is generally below the levelized cost of many generating technologies[7] (both conventional and green), thereby suppressing the investment signal to expand capacity of these technologies in the region.

2.2 GREEN ENERGY REVENUE STREAMS/PRODUCTS

Green energy or renewable energy generators can also receive the above revenue streams. Some green energy generators may not pursue or may not be eligible for certain revenue streams, such as capacity shown in Figure 1,primarily due to the intermittency or variability of production. This is not strongly detrimental given the large portion of revenue derived from sales of energy, which all generators (assuming a minimum size to participate in wholesale markets) can receive. Nevertheless, the revenue amounts shown above are generally below the costs of green energy, thus state, provincial, and federal governments have provided for various incentives[8] that can reduce the costs of generators and/or supplement the revenues of these generators.

One way to provide supplemental revenue is to enable value creation for certain "attributes" of the power supply that are either not captured by wholesale markets or not demanded by utilities or other purchasers as part of meeting electricity demands. Demand for attributes can be created by regulatory or legislative mandates, and prices or values are determined by the intersection of these demands with supply conditions (amount and cost). In cases where demand exceeds supply, costs may be quite high, which I discuss in later sections. In way of introduction, I perform a comparison of potential revenue streams with and without attribute revenue over the 2008-2013 time period[9] in Figure 2.

[7] See, for example, 2013 data from the U.S. Department of Energy at http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

[8] The focus of this report is on one type of incentive—creating value for the environmental attributes through renewable portfolio standards ("RPS"), which is a market-based approach to monetizing these attributes. There are a number of additional incentives that have been utilized across various jurisdictions. These incentives can be organized into those that reduce the cost of green energy or those that increase the revenue to green energy producers. In terms of the former, the major form of incentive in the United States has been production or investment tax credits ("PTC" or "ITC"), which effectively reduce the cost of supply. Additional cost-reducing incentives include cash grants, accelerated depreciation provisions, and lower-cost financing. In addition to RPS, there are a number of incentives that provide additional revenues or additional revenue guarantees, such as the use of long-term contracts and feed-in tariffs that compensate generators for the full cost of service and usually cover the full value of the green energy including all physical products and environmental attributes. An additional revenue-increasing mechanism is the use of greenhouse gas ("GHG") emissions adders or cap-and trade programs, such as the Regional Greenhouse Gas Initiative ("RGGI"), which effectively increases the price of the physical energy product and thus the revenues to renewable and non-renewable generators.

[9] 2014 is excluded because it only represents three months, which are not likely to be representative of the levels of revenues anticipated over the remainder of the year.

FIGURE 2. AVERAGE ANNUAL WHOLESALE COST/REVENUE COMPARED TO ENERGY PLUS MA CLASS I REVENUE

Figure 2 utilizes the same data from the prior figure but also adds the value of Class I RECs over the same time period. The lower line represents the sum of the revenue streams shown in Figure 1—energy, capacity, and ancillary revenues. The upper line utilizes the energy cost stream only and adds revenues from Massachusetts Renewable Portfolio Standard ("RPS") Class 1 renewable energy certificates ("RECs"). As such, this upper line is representative of revenues received by an intermittent resource, such as wind imports from Québec that may only elect to provide energy on a real-time basis to New England and also receive revenues from sale of the environmental or RPS-related attributes.

The figure shows that REC values and potential REC revenues have rebounded significantly from the 2009-2011 lows. At that time, optimistic projections of new renewable project development coupled with a pre-shale supply outlook on natural gas prices (and by extension New England energy prices) led some observers to believe that REC prices would remain at these relatively low levels. Nevertheless, even in those years, REC revenues would have represented a significant increase (about 30%) in generator revenues above just wholesale market revenues. In 2012 and 2013, REC prices rebounded and the REC value actually exceeded the energy values; forecasted REC values are expected to remain elevated (discussed below). **In sum, sale of environmental attributes provides a significant revenue stream for eligible generating resources that is not burdensome to seek, as discussed in later sections.**

3. RENEWABLE ENERGY CERTIFICATES AND ATTRIBUTES

There are a number of ways to capture the value of the environmental attributes mentioned above. Attributes can be bundled with all products produced by a generator and purchased as part of a contract for energy and capacity. Attributes can also be purchased independently of the energy and capacity, but this latter option requires an instrument or mechanism that describes what is being spun off from the physical, power aspects of delivered energy. Renewable energy certificates serve this function. The U.S. Environmental Protection Agency ("EPA") defines RECs as representing "the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source.[10]" Beyond this basic definition, different jurisdictions establish more detailed distinctions among different types of RECs, which I discuss briefly in a later section. Thus, the "property right" can be created by governmental jurisdictions and other entities, such as independent certifying agencies, but the value attached to these rights will depend on the product/market requirements and credibility of the certifying body.

3.1 REC USES AND BENEFITS

Besides enabling the measurement of non-physical-power attributes of electric generation, an important benefit of RECs is to enable trading of attributes (and hence an increase in the market liquidity of the attributes). Such trading allows supplying entities to be completely independent of entities that need or want to purchase renewable attributes, which is consistent with restructured wholesale and retail electricity markets. Demand for attributes can be required by governments as part of meeting state or provincial laws and/or regulations. Some states or provinces require purchase of green generators' entire output (including RECs), while other states allow entities to purchase just the attributes to comply with laws and regulations. Demand for attributes can also be due to voluntary decisions by entities to change the nature of their consumed electricity. For example, some entities for marketing, image, or social purposes may elect to purchase attributes from environmentally-friendly generators in order to "green up" their power supply[11].

As introduced above, RECs provide an important revenue stream to renewable energy generators and allow them to sell energy, capacity, and other power-related products to markets or certain entities and sell the attributes to other entities. In addition, RECs allow entities (such as local distribution utilities) that have purchased the entire output of renewable generators to then sell renewable attributes in

[10] http://www.epa.gov/greenpower/gpmarket/rec.htm

[11] Green-E is one example of a certificate created independently of regulatory bodies and used for voluntary REC purchases and sales.

order to partially offset the contract cost while at the same time using the power-related products for its own requirements.

An important measurement-related benefit of RECs is the assurance to the buyer that attributes have not already been sold to another entity and hence are worth the purchase price. RECs can be "minted" and assigned unique numerical identifiers specifying the facility that generated the power, the time of generation, the power products, and the attributes (environmental and other). Tracking systems have been developed and maintained to assist with the minting and tracking of REC transactions.

3.2 TRACKING SYSTEMS

Tracking systems are frequently used in conjunction with RECs to facilitate and track compliance efforts by state entities. NEPOOL-GIS is the generation information system ("GIS") used in New England and allows regulators to effectively "out-source" the important functions of reviewing generation amounts by renewable generators and determining (and auditing) whether certificates have been generated, traded, or retired.

NEPOOL-GIS actually tracks all generation (renewable and non-renewable) generated in or delivered to New England and tracks loads by load serving entities or load asset. As such, emissions are also tracked and obligations related to load levels (such as RPS obligations) are estimated. Data are received directly from ISO-NE's market settlement system ("MSS") for most generating and import sources and supplemented by self-reporting and data from third-parties.

Operating rules codify the requirements applicable and processes used by the various participants, which include generator owners, load serving entities, traders and brokers, regulators, among others. In particular, the rules describe what data are available to various entities with separate reports for account holders, regulators, and the public.

NEPOOL-GIS certificate fields are organized into 11 parts: (1) Fuel sources and generation type (2) RPS eligibility for each state, which is a binary value for each standard, (3) Emissions data, in pounds per reporting period for each generating unit, (4) labor characteristics, (5) vintage, including commercial and refurbishment/repowering date, (6) asset information and identification, (7) total MWh generation or conserved, (8) location, which can include non-contiguous control areas, (9) Green-E eligibility and miscellaneous fuel types and detail, (10) third party meter reader for smaller, non-ISO-metered generators, and (11) Regional Greenhouse Gas Initiative ("RGGI") status.

Other tracking systems—PJM's Generation Asset Tracking System ("GATS"), Midwest Renewable Energy Tracking System ("M-RET") and the North American Renewables Registry ("NAR") are three other examples—also collect and include a variety of data in their certificate fields. Each tracking system features a different set of fields but generally track a similar set of basic data, such as production of RECs and compliance with RPS in the region, generation information, and emissions data.

4. OVERVIEW OF NEW ENGLAND RENEWABLE MARKETS

In this section, I briefly describe the different renewable markets in New England. Québec (and HQ's footprint) shares a border with three New England states, thus there is strong potential for sales of renewable attributes to New England. The states in the region have different regulations and laws that place certain eligibility requirements on RECs through the various renewable portfolio standards ("RPS") in the region.

4.1 REQUIREMENTS AND MARKET PARTICIPANTS

In New England, RPS place certain purchase requirements on load serving entities ("LSEs"). LSEs can be regulated distribution utilities that still provide generation service to certain customers that have not migrated to competitive retail supply. LSEs can also be competitive suppliers that currently provide retail supply to commercial, industrial, and residential customers. Requirements are stated in a minimum percentage of total supply per year. These requirements can be met with energy from qualified RPS generators or RECs related to RPS-eligible generation, with the latter being the more liquid and preferred option. Compliance entities generally contract with brokers, competitive power suppliers, or other third-party providers to procure RECs for compliance. Similarly, renewable generators can contract with these same third-party entities to sell RECs. As a result, the secondary market for RECs is quite active and liquid with many potential counterparties.

Given that RPS requirements are a function of load levels, the Massachusetts and Connecticut markets provide the large majority of compliance-related demand from New England.

4.2 CLASSES AND ELIGIBLE TECHNOLOGIES

Renewable portfolio standards in New England contain various "classes" of RECs for which compliance is required. Five of six New England states have mandatory RPS policies (VT excluded). Though details vary, all five RPS policies distinguish between "new" resources that come online after a cutoff date (Class I), and existing resources. Many resources qualify for Class I RECs in multiple states. Maine has made allowances for some existing biomass to qualify for Class I that does not qualify elsewhere, resulting in a significantly lower REC price than the other New England Class I markets. As used in this report, "Premium Class I REC markets" refers to Massachusetts ("MA") Class I, Connecticut ("CT") Class I, Rhode Island ("RI")*New*, and New Hampshire ("NH") Class I and II.[12] Though significant eligibility differences apply (particularly CT Class I), the markets are fungible enough to be thought of generally as a single market.

[12] Maine Class I was previously considered as a "premium" market but recent loosening of eligibility requirements has reduced the value of these RECs.

These premium classes generally contain more restrictions for eligibility and should carry higher prices due to the smaller pool of resource types that are eligible.[13] At the current time (and over the foreseeable future), Class I RECs are the highest priced RECs in New England, but supply/demand dynamics for each of the REC classes ultimately determines prices. Not all classes are available for imported power as some classes require in-state locations (e.g., CT Class III) and have older vintage requirements (e.g., MA Class II) that reduce the relevance of the class to potential imports. Table 1 summarizes the relevant definitions of the eligible resources for the premium (Class I) classes, which are most relevant to import of certificates from outside of New England.

[13] Another factor is that the Alternative Compliance Payment, which is effectively a statutory or regulatory ceiling on prices for RECs, is generally set higher for Class I compared to other RPS classes.

TABLE 1. PREMIUM RPS CLASSES IN NEW ENGLAND (DEFINITION EXCERPTS)

	Definition
CT Class 1[14]	Includes "energy derived from solar power, wind power, a fuel cell, methane gas from landfills, ocean thermal power, wave or tidal power, low emission advanced renewable energy conversion technologies, small (<5MW) 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, or a sustainable biomass facility with an average emission rate of equal to or less than .075 pounds of nitrogen oxides per million BTU of heat input for the previous calendar quarter"
MA Class 1	New Renewable Generation Units are facilities that began commercial operation after 1997 and generate electricity using any of the following technologies: Solar photovoltaic, Solar thermal electric, Wind energy, Small hydropower, Landfill methane and anaerobic digester gas, Marine or hydrokinetic energy, Geothermal energy, Eligible biomass fuel
NH Class 1	Class I resources include generation facilities that began operation after January 1, 2006 and produce electricity from: wind energy; geothermal energy; hydrogen derived from biomass fuel or methane gas; ocean thermal, wave, current, or tidal energy; methane gas; or biomass.[15]
NH Class 2	Includes production of electricity from solar technologies, provided the source began operation after January 1, 2006.
RI New	Eligible renewable resources initially placed into commercial operation after December 31, 1997 that use direct solar radiation, wind, movement or the latent heat of the ocean, or the earth's heat; hydroelectric facilities up to 30 megawatts (MW) in capacity, Biomass facilities using eligible biomass fuels and maintaining compliance with current air permits (eligible biomass fuels may be co-fired with fossil fuels, provided that only the renewable-energy portion of production from multi-fuel facilities will be considered eligible), Fuel cells using renewable resources

Compliance entities must purchase class-eligible RECs equivalent to a certain percentage of obligated load by a certain date each year. All four states allow some form of REC "banking", enabling compliance entities to apply a limited number of surplus RECs toward future obligations. The table below summarizes the minimum percentage requirements by class and by year for the 2014-2023 time period.

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[14] CT Class 1 now has some allowance for large hydro under certain conditions (described in a later section).

[15] The New Hampshire PUC is in the process of developing revised RPS regulations in response to recent legislation. The most relevant change to note here is that useful thermal energy from geothermal energy, solar thermal energy, or thermal biomass renewable energy from units that began operation after January 1, 2013 can be applied toward a limited portion of Class I compliance.

TABLE 2. PREMIUM RPS CLASS MINIMUM PERCENTAGE REQUIREMENTS, 2014-2023

	2014	2015	2016	2017	2018	2019	2020	2021-2023
CT Class 1	11.0%	12.5%	14%	15.5%	17%	19.5%	20.0%	20.0%
MA Class 1	9%	10%	11%	12%	13%	14%	15%	16%+[16]
NH Class 1	5.0%	6.0%	6.9%	7.8%	8.7%	9.6%	10.5%	11.4%+[17]
NH Class 2	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
RI New	6.5%	6.5%	8.0%	9.5%	11.0%	12.5%	12.5%[18]	12.5%
Load-Weighted Average	9.0%	10.1%	11.2%	12.4%	13.6%	15.1%	15.9%	16.5%+

This percentage schedule is aggressive, with Massachusetts currently having no explicit end date for the percentage increase in requirements. On a load weighted average, requirements reach almost 16% of load in New England by 2020.Figure 3 shows the demand levels for the 2013-2023 period. Demand is expected to more than double from 8 million RECs or 8 Terawatt-hours (TWh) to over 18 million RECs in 2023.

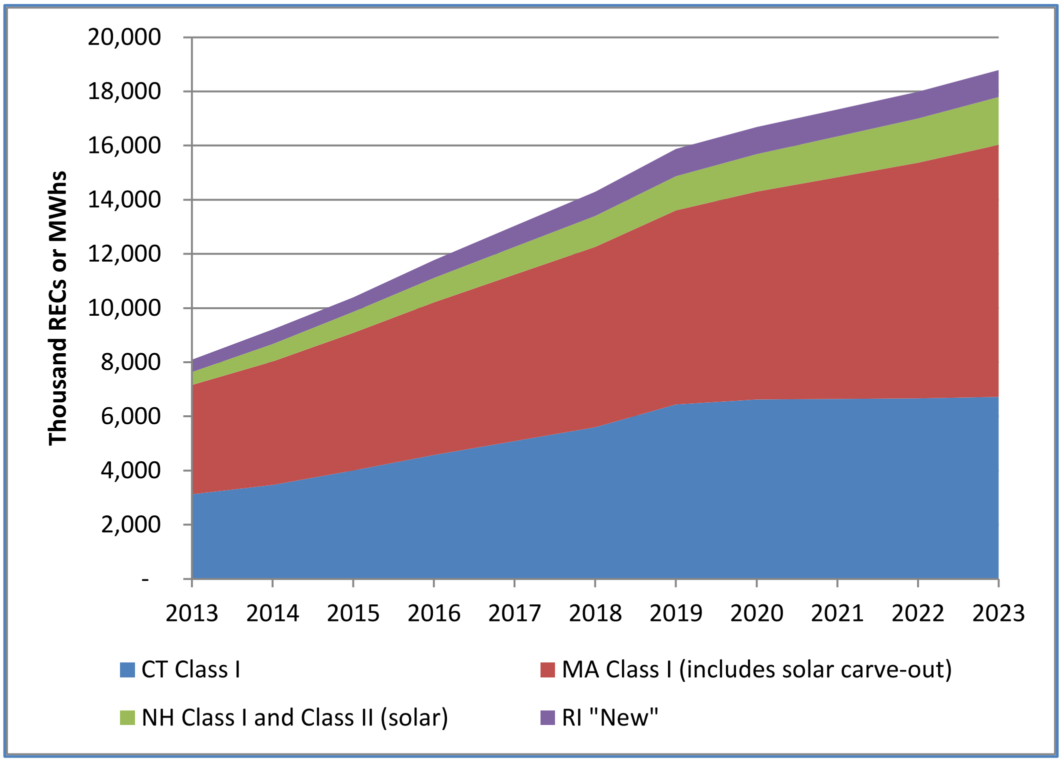
Despite these aggressive goals and currently tight market conditions, there has not been wide scale rollback of RPS provisions. Rhode Island delayed the schedule of increases in minimum requirements by one year starting in 2015, as reflected above. More significantly, Connecticut has allowed the possibility of large hydro offsetting up to a quarter of its Class 1 requirements by 2020 under certain conditions.

[16] After 2020, an additional 1% per year with no stated expiration date. Percentages include in-state solar carve-out.

[17] Yearly increments are 0.9% until reaching 15% in 2025 and maintained thereafter.

[18] Maintained in 2020 and thereafter unless determined otherwise by regulators.

FIGURE 3. FORECASTED PREMIUM REC DEMAND, 2013-2023



4.3 ALTERNATIVE COMPLIANCE PAYMENTS

Alternative compliance payments ("ACP") provide a way for compliance entities to meet their requirement levels without the purchase of RECs and were instituted to provide a cap on the cost exposure of LSEs[19] during shortage conditions. Use of ACP increases as conditions approach or are at shortage conditions. ACPs are generally set at a rate that increases with inflation—Connecticut is the exception. Table 3 shows ACP levels for 2014.

[19] States have flexibility in how they utilize ACP collections, but generally speaking, ACP are used to advance clean energy goals. See, for example, Massachusetts 2012 plans:http://www.mass.gov/eea/docs/doer/rps-aps/cy-2012-acp-spending-plan-042314-pdf.pdf

TABLE 3. PREMIUM RPS CLASS ALTERNATIVE COMPLIANCE PAYMENT ($/MWH)

	2014
CT Class I	$55.00
MA Class I	$66.16
NH Class I	$55.37
NH Class II	$55.37
RI New	$66.16

As discussed below, current REC prices are close to ACP levels due to shortage conditions (REC supply being less than REC demand). Given that the highest ACP levels are in MA and RI, those states' RPS should attract RECs before other states' markets.

4.4 VOLUNTARY REC MARKETS

In addition to the above compliance markets, generating resources in and outside of New England can receive certification for sale in voluntary REC markets. Green-E certification is the largest independent certification program for use in voluntary REC sales in the U.S., but others do exist[20].Voluntary certification is tracked in numerous generation information systems ("GIS") around the U.S. However, not all voluntary REC transactions are tracked in GIS systems, and different GIS systems track different transactions and at varying levels of detail.

EcoLogo is another certification program and was mentioned by HQD in its application (see p. 39). EcoLogo is owned by United Laboratories ("UL") and is a multi-attribute certification program that certifies products, services, and packaging for "reduced environmental impact."[21] HQD's participation in voluntary markets would presumably be covered by standard CCD 003 "Renewable Low Impact Electricity Products." Certification is achieved by submitting an application, and verification and review is subsequently administered by UL and its contractors.

Generally speaking, the value (and cost) of voluntary RECs are much lower than the premium markets discussed above. These markets feature less rigorous and uniform tracking (of production and possibly retiring) of certificates and eligibility requirements for resources—such as delivery to consuming region—are looser. For example, Green-E RECs are tracked by NEPOOL-GIS and other North American registries; by contrast, EcoLogo is not tracked in NEPOOL-GIS, PJM-GATs or the North American Registry, but did appear in M-RETS (the tracking system used in the Midwest U.S.).Green-E RECs (and EcoLogo) do

[20] See "Market Brief: Status of the Voluntary Renewable Energy Certificate Market (2011 Data)", a report issued by the National Renewable Energy Laboratory, U.S. Department of Energy.

[21] For more information, see http://www.ul.com/global/eng/pages/offerings/businesses/environment/services/ELmark/index.jsp

not have to be delivered to the consuming region and thus can include RECs produced by relatively cheap resources, such as wind located in Texas or the Midwest U.S.

In terms of price, I was unable to find any market information regarding the value of EcoLogo RECs, but prices for other voluntary markets are about $1/MWh[22]. A comparison of this value against current and anticipated values for premium REC markets in New England shows that HQD is likely not maximizing revenue from sale of environmental attributes if it chooses to pursue the path of voluntary REC markets in lieu of premium Class I markets; these are lost revenues that could be used to offset ratepayer cost. This is the case at the current time and over the time period covered by the supply plan. Indeed, it may be more beneficial to keep the RECs and the property rights associated with the environmental attributes than to sell these attributes at such reduced prices.

[22] See U.S. DOE Green Power Network data at http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5

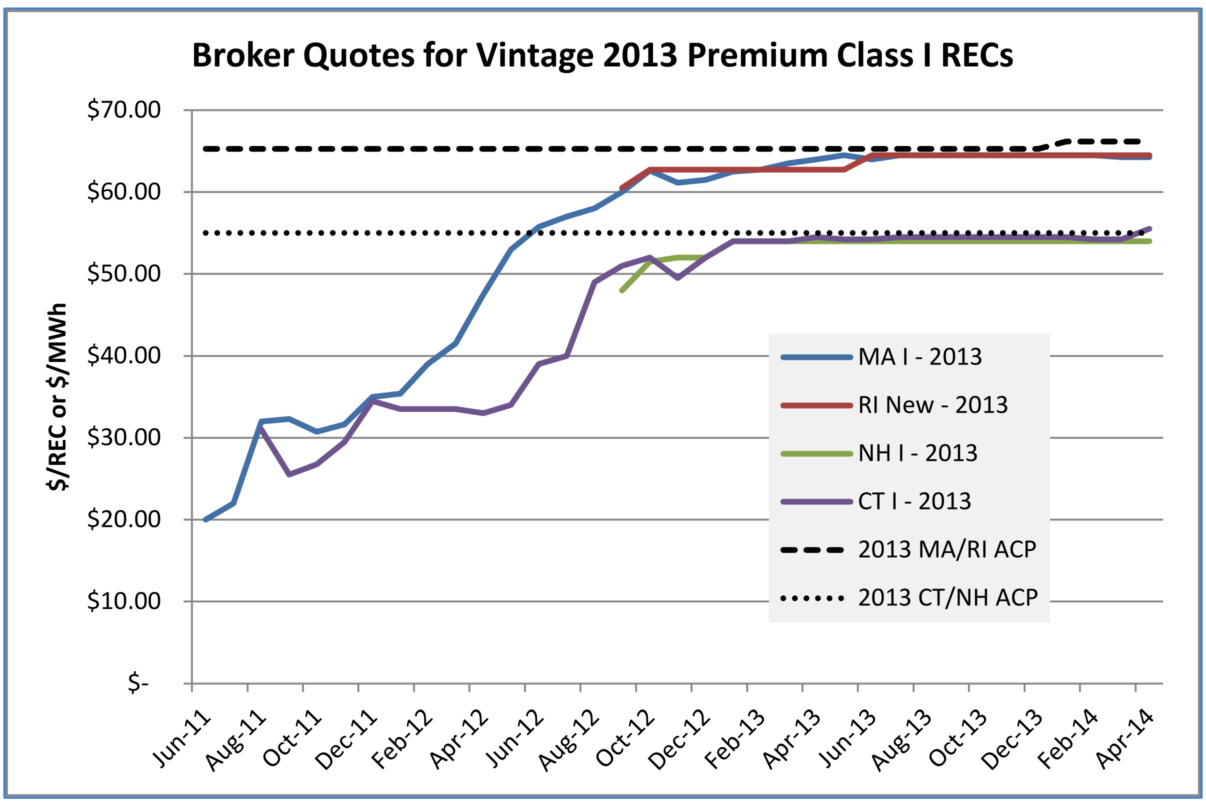
5. RENEWABLE ENERGY MARKET CONDITIONS IN NEW ENGLAND

The renewable energy market in New England is currently in a state of shortage. As was shown in Figure 2, prices for MA Class I RECs have increased significantly and are at all-time highs. Prices are determined by a number of factors that influence the basic relationship between supply and demand (including the requirements discussed in the prior section and revenues, costs, and other incentives relevant to renewable generators. In this section, I describe current market conditions in New England. I first show current forward prices (as determined by broker sheets) and then discuss a more “fundamentals” based forecast that relies on supply/demand factors. As I will show below, the current shortage conditions are expected continue for the foreseeable future.

5.1 CURRENT FORWARD PRICES

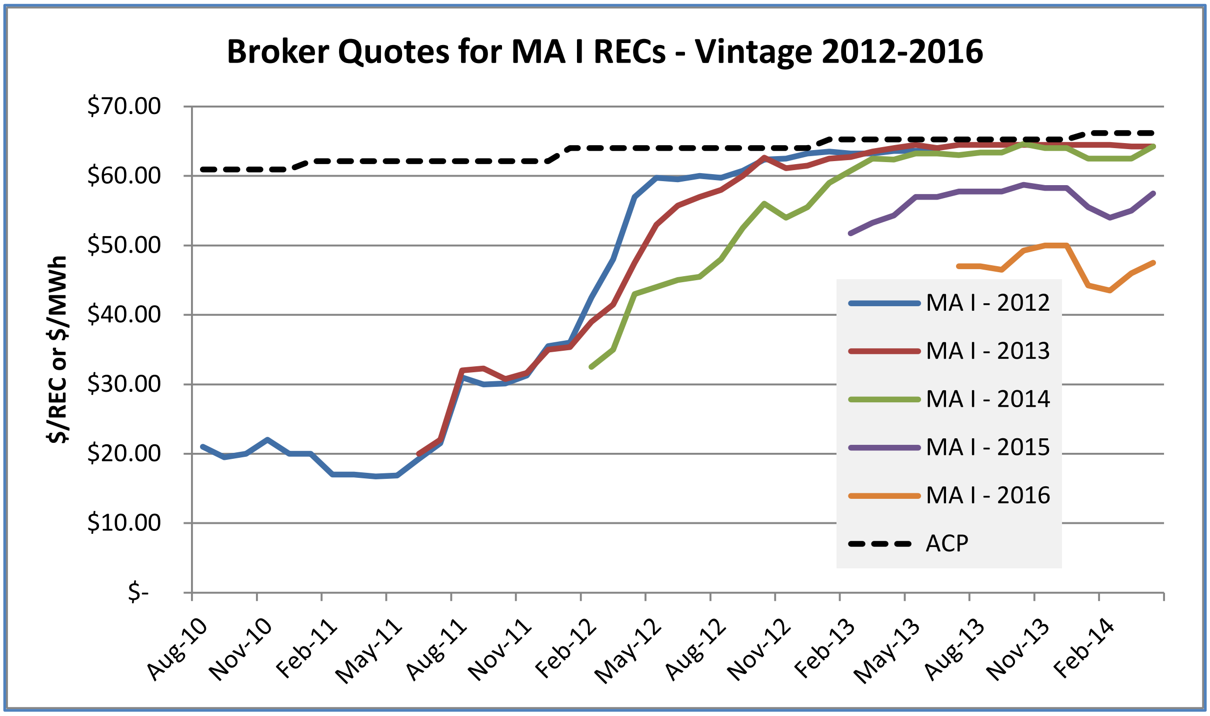
Today, premium Class I REC markets are significantly undersupplied, which is reflected in RECs trading at or just below the price cap established by the ACP. The figure below shows how broker quotes for 2013 premium Class I RECs converged to the ACP beginning in late 2012.

FIGURE 4. BROKER QUOTES FOR VINTAGE 2013 PREMIUM CLASS I RECS



The following figure shows how forwards for MA I RECs – the most important New England REC market due to size, liquidity, and high ACP – have been converging toward ACP for vintage 2014 and 2015 RECs as well.

FIGURE 5. BROKER QUOTES FOR MA CLASS I RECS – VARIOUS VINTAGES



5.2 SUPPLY/DEMAND BALANCE

Demand levels are largely determined by regulations (and legislation)—there may be some voluntary demand beyond compliance-required levels, but this portion of total demand is likely extremely small—and thus does not generally change with price[23]. The intersection of an upward-sloping supply curve—as prices rise, one would expect supply to increase[24]—with demand levels will determine the price.

[23] Except for banking, RPS compliance in a year must be met by renewable energy generated in that year; hence, 2012 compliance can be met by 2012 vintage RECs. The ability to bank certificates also accounts for demands, especially when prices for future vintages or compliance years are higher or are expected to be higher than current vintage prices.

[24] There may be some inherent inelasticity due to siting issues, construction lead times, and other factors.

Based on analysis of data gleaned from Massachusetts, Rhode Island, and New Hampshire compliance reports, our view is that the annual shortfall of premium Class I RECs in 2011 (ignoring banking considerations) was about 500,000 RECs (equivalent to 500 GWh), as shown in Table 4. That is the equivalent to the output from almost 200MW of wind generation (at a 30% capacity factor).

Some of this shortfall was offset with banked RECs from 2009 and 2010, when the market was oversupplied. Nevertheless, obligated entities made ACP payments equivalent to about 350 GWh, or 6% of the total requirement in 2011. The extensive use of ACP payments indicates that most obligated entities had largely exhausted their banked REC supplies by the end of 2011, which led to prices close to ACP as the compliance deadline approached.

TABLE 4. ESTIMATED SHORTFALL IN 2011 PREMIUM CLASS I RECS

Estimated Shortfall in 2011 Premium Class I RECs					
	MA-I	RI-I	NH-I	CT-I	Total (Rounded)
Class I Requirement (MWh)	**2,882,823**	**285,531**	239,000	2,500,000	5,907,000
NEPOOL GIS Certificates (double counts multiple registrations)	**3,090,525**	**1,239,338**	**1,142,438**	**3,754,062**	9,226,000
Settled RECs as % of GIS certificates	*85%*	*17%*	*18%*	*63%*	*59%*
2011 Settled RECs	**2,613,122**	**210,478**	202,168	2,375,000	5,401,000
ACP Credits Applied	**106,203**	84,402	**36,832**	125,000	352,000
ACP credits as % of obligation	4%	30%	15%	5%	6%
Annual Shortfall (prior to counting banked RECs and ACP)	**269,701**	**75,053**	36,832	125,000	507,000
Shortfall as % of Requirement	9%	26%	15%	5%	9%
Yellow cells indicate extrapolations or estimates in absence of public data.					

Most states provide six months following the end of the compliance year for obligated entities to meet RPS requirements. The approach of the compliance deadline for 2011 (June 30, 2012) coincides with the sharp uptick in forward prices in MA Class I and other Class I markets (see Figure 2). Iconsider it likely that the market was reflecting the realization of the severity of the 2011 supply shortage, and a belief that the shortage would persist for the next few years at least. This shortage can be seen in the analysis of 2012 data (see Table 5). The use of ACP credits in 2012 accounted for about8% of compliance in Massachusetts, which is double the 2011 percentage. A review of the 2012 pricing data shown in Figure 5 indicates the run up in 2012 vintage prices to levels near ACP as the compliance deadline (mid-2013) approached.

TABLE 5. ESTIMATED SHORTFALL IN 2012 PREMIUM CLASS I RECS

Estimated Shortfall in 2012 Premium Class I RECs	2012	2012	2012	2012	
	MA-I	RI-I	NH-I	CT-I	Total (Rounded)
Class I Requirement (MWh)	3,349,611	**365,545**	320,746	2,900,000	6,936,000
NEPOOL GIS Certificates (double counts multiple registrations)	**3,643,818**	**1,496,522**	**1,513,997**	**4,525,582**	11,180,000
Settled RECs as % of GIS certificates	*84%*	*22%*	*18%*	*61%*	*57%*
2012 Settled RECs	3,056,894	**330,350**	273,191	2,755,000	6,415,000
ACP Credits Applied	255,388	35,195	47,555	145,000	483,000
ACP credits as % of obligation	8%	10%	15%	5%	7%
Annual Shortfall (prior to counting banked RECs)	**292,717**	**35,195**	47,555	145,000	520,000
Shortfall as % of Requirement	9%	10%	15%	5%	7%
Yellow cells indicate extrapolations or estimates in absence of public data.					

After 2012, Premium Class I RPS requirements are scheduled to increase by about 1% of retail sales each year, in addition to any increases due to load growth. Figure 3 above showed an estimate of actual and projected premium Class I REC demand. Note that Massachusetts accounts for almost 50% of demand. The figure showed that after compliance year 2012, incremental REC requirements are projected to increase each year on average more than 1 million RECs (1 TWh) per year until 2020, when demand increases subside a bit. In other words, more than 400 MW of new wind generation or its equivalent needs to qualify in premium Class I REC markets each year just to keep up with scheduled increases in the RPS requirements.

Very little public data are yet available for compliance year 2013 since firms still have time to comply, so it is difficult to quantify the REC shortfall for the prior year. However, the increase in RPS requirements (primarily due to escalating percentage requirements), relatively light new project development, and high REC price signals for 2013 vintage RECs strongly indicate that the undersupply situation persists to the present time.

Although data for 2013 is very preliminary, indications are that the shortage conditions in 2013 will also continue through 2014. The best evidence of the continuation of the shortage conditions is that REC prices continue to trade close to ACP. As of April 2014, REC prices for Massachusetts Class I RECs were $64 per MWh for both 2013 and 2014 compared to ACP prices of $65.27 and $66.16 per MWh for 2013 and 2014, respectively (see Figure 4 and Figure 5). The small difference between current REC market prices and the ACP is likely due to transaction costs associated with REC procurement.

5.2.1 *INCLUSION OF LARGE SCALE HYDROPOWER IN CONNECTICUT RPS*

In 2013, Connecticut passed changes to its RPS[25]that would allow large scale hydropower to substitute for Class I Resources under certain conditions. This change appears to be a reaction to the high REC prices at the time and the anticipation that these high prices would continue. The original intent of the RPS was to provide additional revenue support beyond energy market revenues to support renewable energy resources that may have above market costs. Given that large scale hydro is generally considered to not be above market and thus is not in need of such additional revenues, the CT legislation set certain conditions for inclusion of large scale hydro. The following steps have to happen for large scale hydropower to substitute for Class I resources under the Connecticut RPS:

1. Alternative Compliance Payments are made in a given calendar year, presumably due to an insufficient supply of Class I resources.
2. If there is a presumption of insufficient supply of Class I resources, the Commissioner of the Department of Energy and Environmental Protection ("CT DEEP") may determine whether such payments resulted from intentional or negligent action by the electrical supplier or electrical distribution company decisions not to purchase RECs available in the market.
3. If the Commissioner finds that the ACP payments were a result of a shortage of RECs, the Commissioner shall determine the adequacy or potential adequacy of Class I renewable energy resources to meet the succeeding years' renewable portfolio standard requirements.
4. The Commission solicits proposals for Class I resources and select proposals up to the amount of resources required to meet the projected shortage of Class I resources. These contracts are reviewed by the PUC.
5. If after the Class I procurement process is complete there is still a shortage of Class I resources, the Commission may after January 1, 2016, allow up to one percent (1%) per year of the requirement to be satisfied by large scale hydropower procured by the Commission. The large scale hydropower must be in the best interest of ratepayers and may have contracts up to 15 years in length. The maximum amount large scale hydropower could reduce the RPS is 5 percent (5%) of retail load.

It is important to note that the large scale hydropower will not be compensated on the same level as Class I resources nor will it generate Class I RECs, but it does reduce the total size of the premium REC market and thus demands for these RECs. As a result, if Hydro Québec Distribution sells Class I RECs to the New England market, it increases Class I REC supply and thereby reduces the chance that large scale hydro would substitute for a portion of the RPS.

[25] An Act Concerning Connecticut's Clean Energy Goals, as amended, on May 28, 2013. http://www.cga.ct.gov/2013/FC/pdf/2013SB-01138-R000879-FC.pdf

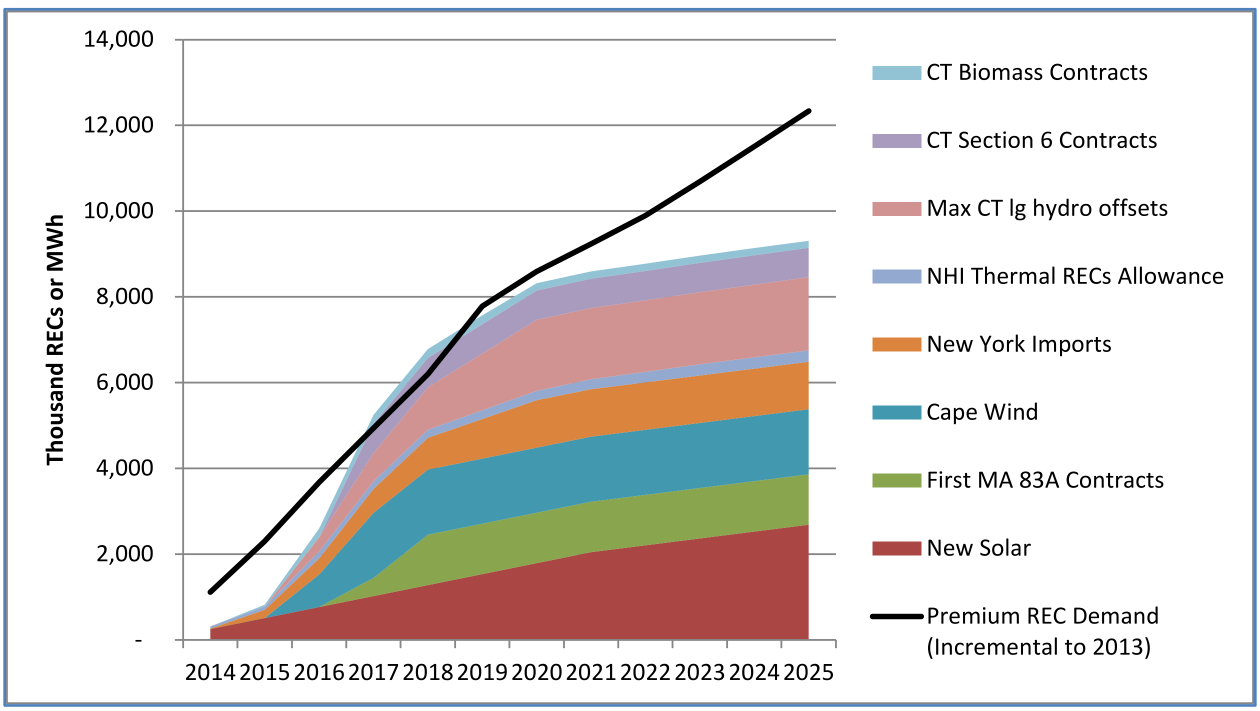
5.2.2 *HIGH SUPPLY OUTLOOK*

La Capra Associates has developed a high supply outlook of new (incremental to what was already online at the end of 2013) Class I REC supply over the next 10 years in order to gauge the potential for REC imports from Québec. This level of supply requires a number of aggressive assumptions regarding online dates for projected projects, full build-out to meet certain RPS carve-outs and classes, high capacity factors (80%) for biomass plants, and increased use of imports from neighboring regions for RPS compliance. In particular, the following assumptions are utilized:

- An increase in supply from New York resources due to expiring 10-year NYSERDA contracts;
- The projects currently under contract in Massachusetts Section 83A program;
- The projects currently under contract in Connecticut;
- The maximum amount of thermal RECs being used for compliance in New Hampshire;
- The maximum amount of large hydro being used in place of compliance in Connecticut;
- Cape Wind fully online by 2017 at full proposed size (468 MW); and
- States' steady progress toward and meeting solar goals.

Give the aggressive nature of these assumptions, this outlook assumes that the minimum amount of supply will be needed from additional resources (not listed above) to meet demand levels. This amount could potentially include sales from renewable projects contracting with HQD. This high supply is shown against the incremental demand from 2013 onward in the figure below.

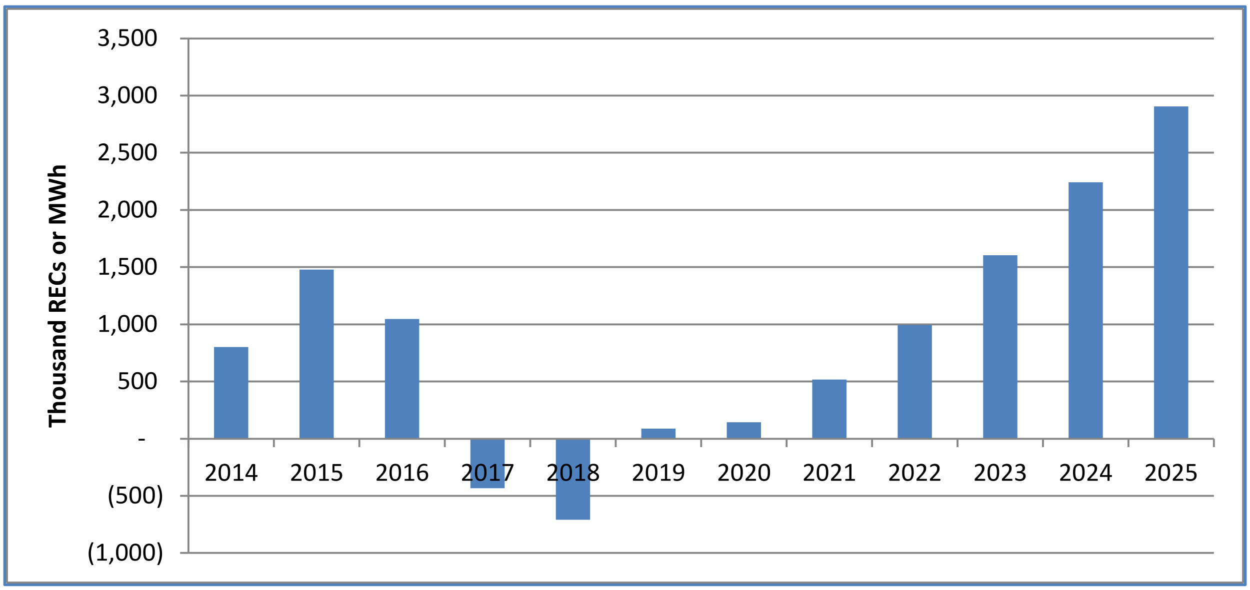
FIGURE 6.PREMIUM REC HIGH SUPPLY SCENARIO



The data from Figure 6was used to create a graph (see Figure 7) showing years of over and under supply under high supply conditions in New England and assuming no shortage of supply in 2013. Given the large shortfalls in 2011 and 2012 documented in the compliance reports and discussed above, and given that project development activity and REC price signals gave no indication that the shortfalls were alleviated in 2013, this assumption makes our estimates of REC undersupply conservative under any future REC supply scenario.

Even with the aggressive supply assumptions described above, Figure 7 shows that there will be an undersupply in every year but 2017 and 2018. It is important to note that even in this scenario there would likely still be a demand for RECs in 2017 and 2018because of the ability of entities with REC compliance obligations to bank RECs for compliance in future years.

FIGURE 7. REC UNDERSUPPLY UNDER HIGH SUPPLY SCENARIO

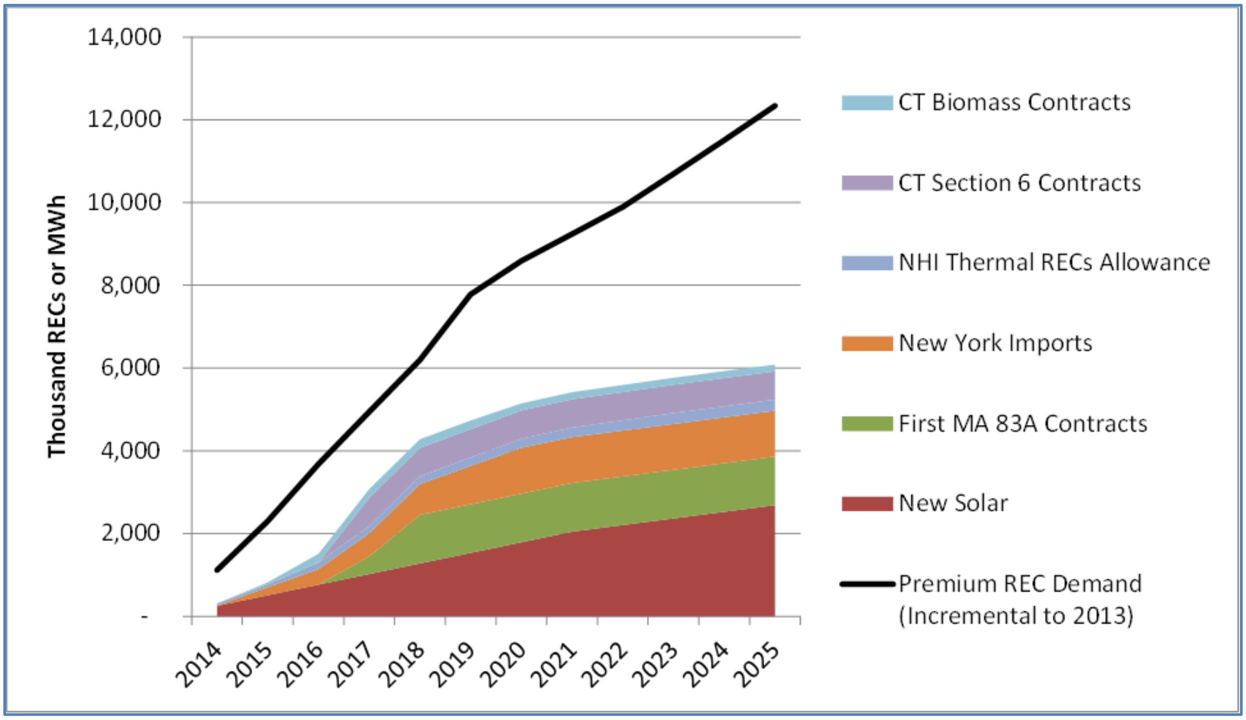


The potential undersupply shown in the figure above is equivalent to the potential market for Class I RECs from Québec assuming the assumptions in Figure 6hold true. The potential market could be even larger if some of these assumptions are altered, notably the assumption about large scale hydro imports, which requires a number of conditions to be met in order to be eligible to meet premium market demands and delays in the commercial operation date of Cape Wind.

As a result, I have developed an estimate of a Low Supply Scenario that has less aggressive assumptions related to other potential sources of supply in and to the region. In this scenario I have assumed that

Cape Wind is never built[26] and Connecticut does not allow large hydro to substitute for any of its RPS compliance. The other assumptions are the same as found in Figure 6. The total supply is shown in the figure below.

FIGURE 8. PREMIUM REC LOW SUPPLY SCENARIO

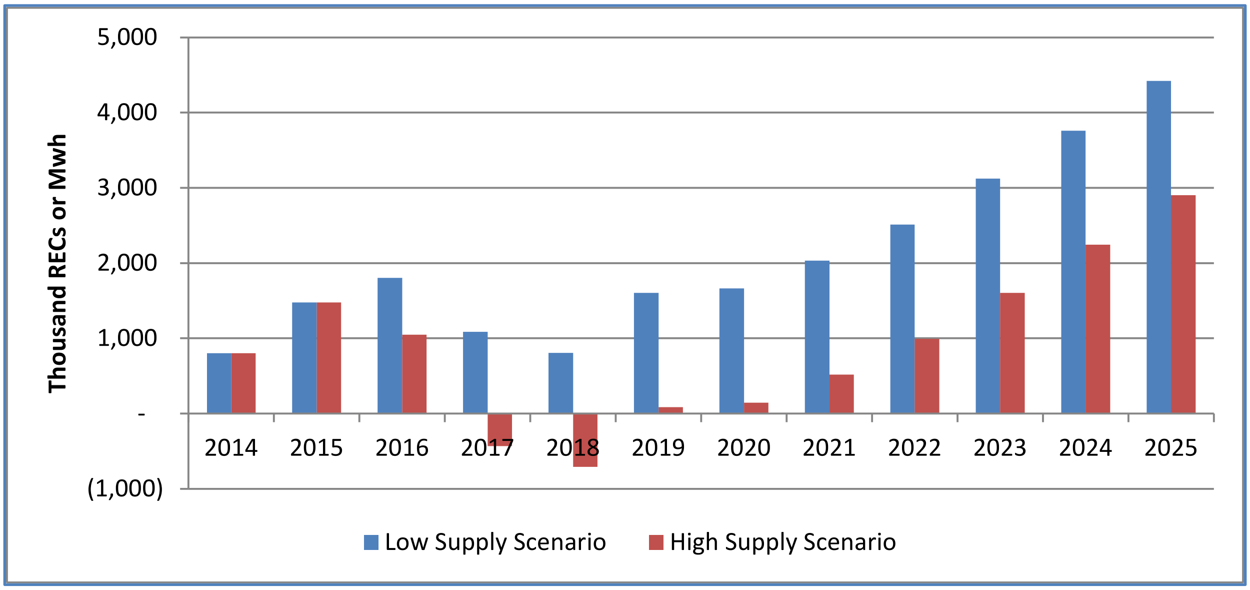


I provide this scenario as a bookend to the high supply scenario shown above, but a lower supply outlook than shown in Figure 8is possible. For example, the CT Section 6 and MA 83A contracts are with facilities that are not yet commercial. Delays in these projects can occur, and it is possible that some projects will not achieve commercial operation.

The resulting undersupply under low supply conditions is shown in the figure below as compared to the undersupply in the optimistic supply scenario. In the low supply scenario the need for additional RECs begins at around 800,000 RECs (800 GWh)in 2014 and grows to almost 4,500 GWh/year in 2025. As with the high supply scenario, the estimate of undersupply does not include the pre-existing undersupply as of the end of 2013, which is expected to be at least the 2012 estimated level (see Table 5) or about 500,000 RECs (500 GWh).

[26] According to Cape Wind, the project has secured the majority of its financing and has recently completed geophysical surveys of the project site and offshore cable routes. It expects to complete its financing by the end of 2014 with construction commencing in 2015 and a commercial operating date by Summer 2016. See www.Capewind.org

FIGURE 9. UNDERSUPPLY IN HIGH AND LOW SUPPLY SCENARIO



5.3 NEW ENGLAND CLASS I FORECASTED PRICES

Our forecast of Class I REC prices was created using La Capra Associates' proprietary supply/demand model. The model uses publicly available regional load and system information from ISO New England, published information on renewable energy portfolio requirements in New England under current statute, and data on renewable resources already online to estimate REC market demand today and in the future. A supply curve is built up using our estimates of renewable potential and costs in the region. A market clearing REC price is calculated for each year of the forecast period. Although total supply and demand are aggregated across Massachusetts, Connecticut, New Hampshire and Rhode Island Class I, the marginal REC is assumed to clear in the MA I market. Broker quotes were used for the first several years of the study period to ensure that the forecast was consistent with current market conditions.

This analysis assumes that the production tax credit is extended beyond current law, but phases out by 2020. Current New England renewable portfolio standards policies, including scheduled changes in eligibility and increases in requirements, are assumed to continue through 2025. As with the high supply scenario analysis above, I have assumed that the maximum amount of large hydropower is procured to offset Connecticut RPS requirements.

The confidential[27] forecast is shown in Appendix B. The forecast shows high prices throughout the study and the procurement plan period.

[27] La Capra Associates utilizes its proprietary REC market model for its forecasts and thus considers the model and model results as confidential and only available via an executed confidentiality agreement.

The forecasted REC prices can be considered as the cost per REC to meet any supply gaps (or the revenues that would be available to parties, such as HQD, that provide this supply) after considering state-contracted projects and other projects that are likely to be developed. The greater the extent that supply is available to meet demand, as in the high supply scenario (Figure 6), the more likely are the prices shown by the REC forecast curve. By contrast, the low supply scenario (Figure 7), which excludes large scale hydro and other resources that would meet demand levels, would more closely correspond to the higher MA ACP prices shown in the figure in Appendix B.

6. HQD PARTICIPATION IN NEW ENGLAND MARKETS

HQD has indicated that it has no plans to re-sell renewable energy into neighboring markets (presumably including New England). In this section, I discuss the three main requirements or actions involved in enabling these sales in an effort to assess the strength of these requirements as potential barriers and reasons for HQD's reluctance.

6.1 ISO-NE MARKET PARTICIPATION

ISO-NE is an important facilitator in attribute or REC transactions. As discussed earlier, ISO-NE provides data to NEPOOL-GIS for assistance with compliance. ISO-NE, as the market and system operator in New England, also facilitates the delivery of power between neighboring regions and New England. Given that RECs have to be delivered to New England, this delivery must involve an ultimate sale to an entity located in New England, thus involving the ISO-NE markets (energy and possibly capacity[28]). Market participation at ISO-NE requires a number of steps ranging from submitting various applications in order to become a market participant and regular interaction with market interfaces to submit bids and offers where applicable. Though HQD is not a market participant, it could contract with existing market participants to provide such services. Thus there should be little incremental cost and effort to enable ISO-NE market transactions in support of REC sales.

6.2 CERTIFICATION OF RESOURCES

Generation resources seeking to sell RECs in one of the premium REC markets must apply for certification of the generator or energy source. Each New England state has separate certification processes, which usually involves submittal of an application and review by a regulatory agency. This process is not onerous and is much less involved than the ISO-NE market participant process. The entire process generally takes a few months. Though I did not perform an exhaustive review of the EcoLogo certification process, I would expect that if HQD can certify its facilities through that process, then it should be possible to complete one or more of the various premium market state certification processes.

Applications usually require information regarding the applicant and the resource (location, fuel type, and commercial operation data, among others). Also required is identification of the metered data source including the process by which these data will be report to NEPOOL-GIS. For generation assets outside of the ISO-NE control area, NEPOOL-GIS assigns asset IDs with the designation "IMP." A review

[28] Massachusetts differentiates between intermittent and non-intermittent Class I resources, with the additional requirement on non-intermittent resources to provide capacity to the region.

of the NEPOOL-GIS website (see Table 6) shows the following resources (along with their REC eligibility)[29].

TABLE 6. QUÉBEC-LOCATED GENERATING UNITS IN NEPOOL-GIS

Unit ID	CT Class I	MA RPS Class I Renewable Generation Unit	RI New Renewable Resource	NH Class I	Green-E	Low Impact Hydro Institute	Unit Name	Location	Fuel Type
IMP38658	Yes	No	No	No	No	No	Parc éolien du Renard	Quebec	Wind
IMP32614	Yes	Yes	No	No	No	No	Mount Miller	Quebec	Wind
IMP32613	Yes	Yes	No	No	No	No	Mount Copper	Quebec	Wind
IMP33636	No	No	No	No	No	No	Masson U4	Quebec	Hydroelectric/Hydropower
IMP33638	No	No	No	No	No	No	Masson U3	Quebec	Hydroelectric/Hydropower
IMP33639	No	No	No	No	No	No	Masson U2	Quebec	Hydroelectric/Hydropower
IMP33637	No	No	No	No	No	No	Masson U1	Quebec	Hydroelectric/Hydropower
IMP36975	Yes	No	No	No	No	No	Lidya	Quebec	Landfill gas
IMP37935	Yes	Yes	No	No	No	No	Le Nordais	Quebec	Wind
IMP35313	Yes	No	No	No	No	No	Gazmont	Quebec	Landfill gas
IMP35868	No	No	No	No	No	No	Dufferin U2	Quebec	Hydroelectric/Hydropower
IMP35867	No	No	No	No	No	No	Dufferin U1	Quebec	Hydroelectric/Hydropower

The table shows that there are currently six generating resources that are eligible for at least one premium REC market with three facilities (all wind) eligible MA Class I resources, the most lucrative premium market for REC producers[30]. These facilities are generally under long-term contracts with HQ Production under a long-term power purchase agreement ("PPA") and are likely selling Class I RECs into New England, though precise amounts are not public information.

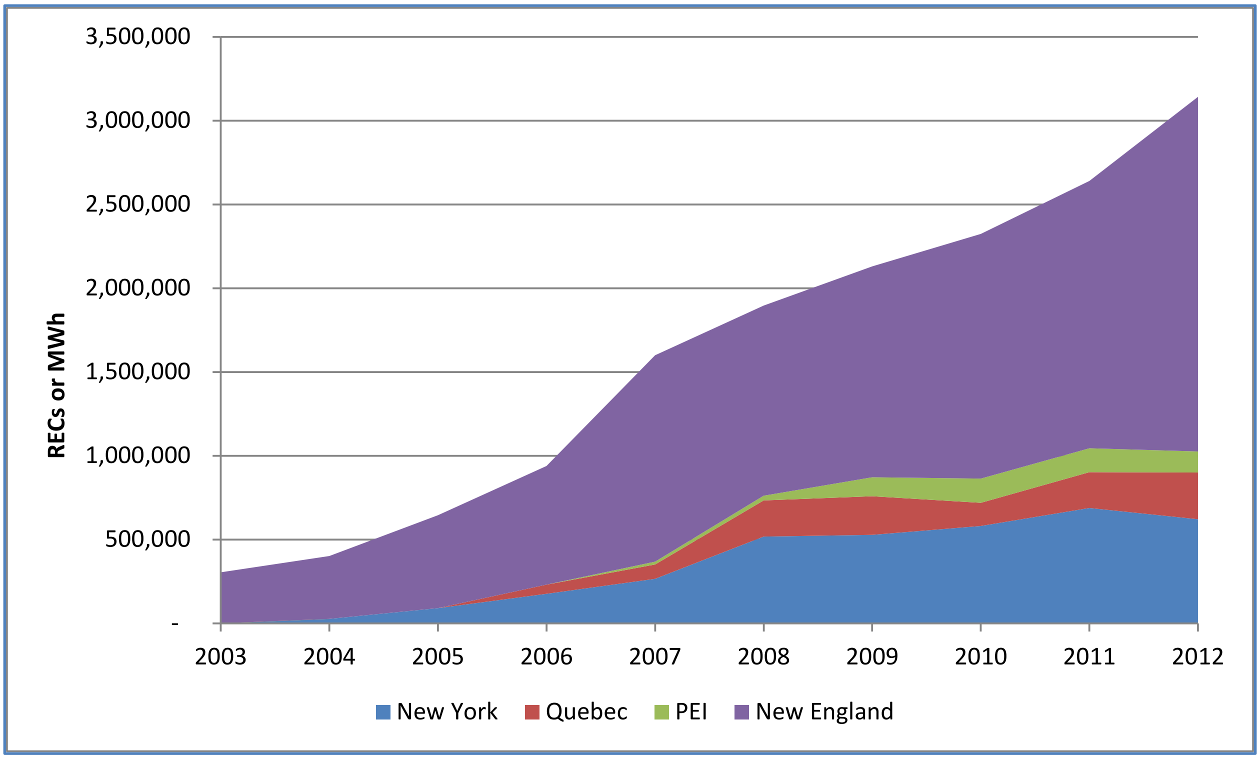
[29] Information on the NEPOOL-GIS website typically lags by a calendar quarter or two, so this table may not reflect recent registrations or changes in eligibility.

[30] These facilities may have also received certification from the EcoLogo program, such as the case of Le Nordais, in addition to being certified as MA Class I.

The ownership of the environmental attributes is specified as part of the contract or PPA terms. Overall, it appears that HQD's contracts with its wind facilities convey ownership of the attributes to HQD. In addition, these contracts, with little exception, place the burden of registering and applying for Class I certification on the seller rather than the buyer if a request to certify is made by the buyer[31]. Such a provision further reduces any administrative burdens or costs to HQD.

Historically, imports from Québec have been used for compliance in premium Class I markets. Figure 10 shows data by location of the generation used for compliance with MA Class I requirements.

FIGURE 10.MA CLASS I COMPLIANCE BY LOCATION OF RECS[32]



Overall, imports from Québec play a role but it is small compared to New York imports, which is probably related to transmission availability (discussed below), but other factors, such as decisions by individual market participants in each region, may also have an impact. Québec imports have averaged about 173,000 RECs (173 GWh) per year with a maximum of 279,000 RECs (279 GWh) in 2012 (probably due to high Class I REC prices). A comparison of these values with the data found in Figure 9 shows that the level of imports would have to grow significantly to fill the undersupply for most years in the 2014-2025 time period. Interestingly, imports increased in 2010 and 2011 despite the relatively low prices

[31] For example, see section 24.2 of the contract between HQD and Le Plateau Community Wind L.P.

[32] Source: MA DOER Annual Compliance Reports

experienced in those years, indicating that participants outside of New England still considered these markets to hold value even at the low prices in those two years.

6.3 TRANSMISSION AVAILABILITY

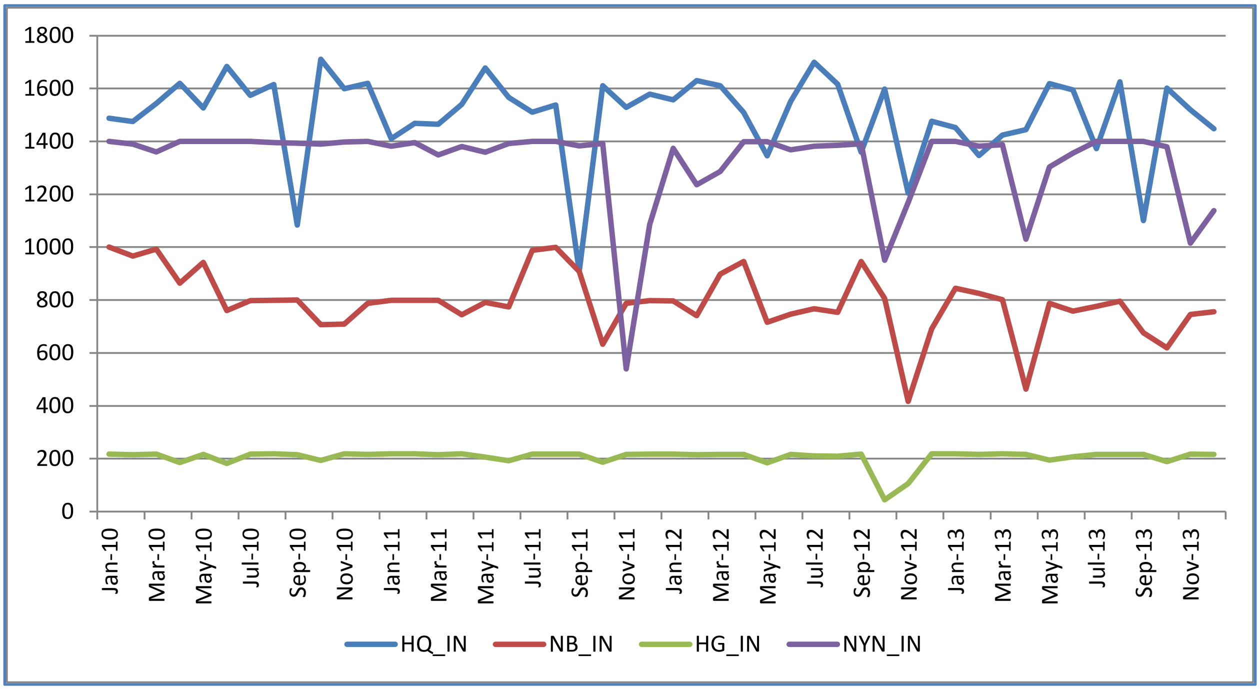
A critical component in accessing New England premium REC markets is compliance and tracking by NEPOOL-GIS, which implies deliverability into New England and sales into New England markets. In order to participate in New England's real time energy market (and thus be eligible for energy and REC value), resources must have transmission reservations in place. Imports from Québec can be facilitated through the HQ Phase II facilities (Radisson to Sandy Pond), the Highgate facilities ("HG"), the New Brunswick facilities ("NB") or wheeled through NY-ISO through Roseton ("NYN").

HQD discusses interconnection capacities in Appendix 4d of its filing. The Phase II facilities (Radisson-Nicolet-Sandy Pond), which they label as "NE-HQT," have an import capacity of 2000 MW and the HIGH-HQT facilities have an import capacity of 170 MW; NB has an import capacity of 785 MW. Due to a number of factors discussed in the Appendix, the effective import capacity that can be relied upon for these interconnections drops down to zero for both the Phase II and Highgate facilities.

ISO-NE also publishes these capacities on a real-time basis and a reliability planning basis. Values for export capability from Québec (or imports to New England) are of primary value to this study. For Phase 2, the value used by ISO-NE for reliability purposes (and imports of capacity) is 1400 MW, but deliveries can (and do) exceed this amount on a real-time basis, which is of greater relevance for the energy markets and delivery of RECs. ISO-NE calculates total transfer capability ("TTC"), which is the amount of power that can be moved reliably between areas in the transmission system, based on NERC standards and existing system conditions.

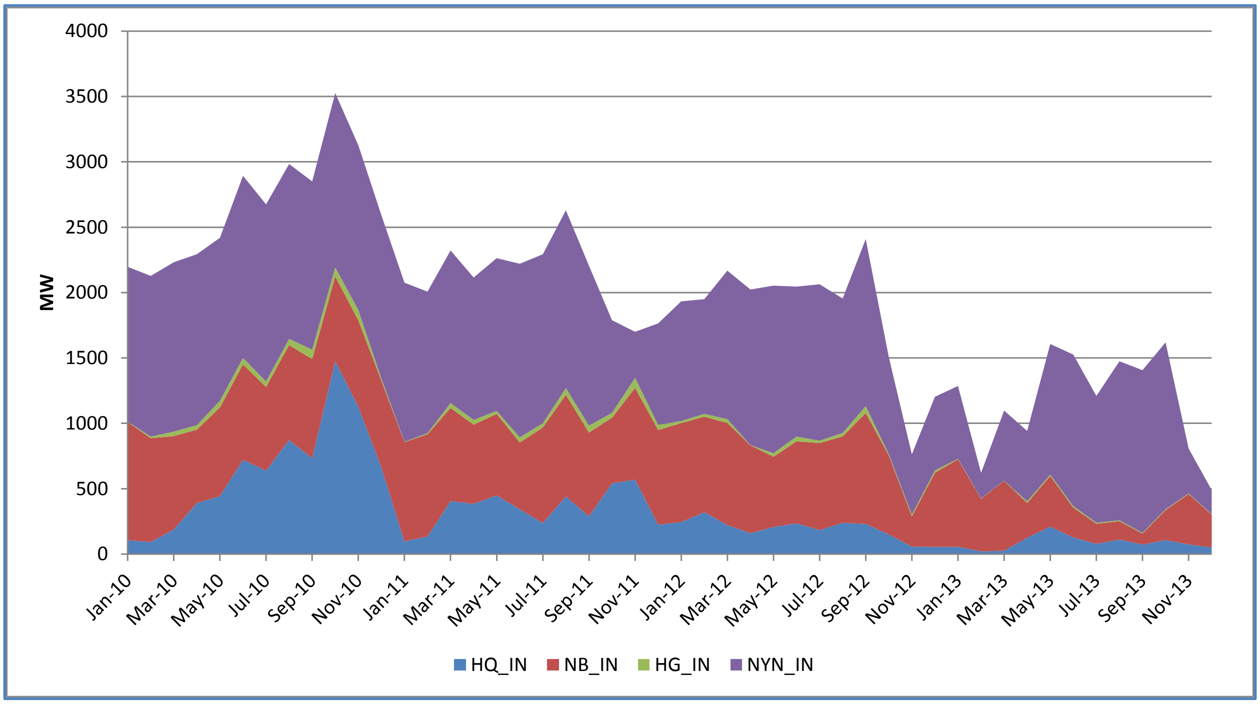
Figure 11 shows monthly averages for hourly historical TTC data from ISO-NE; ISO posts daily (at a minimum)a weekly outlook of available TTCfor each hour. Though the numbers are subject to change the closer one gets to real time, the figures represent an excellent estimate of the availability of the line; these values are generally greater than what would be used for planning or reliability purposes. For example, the 1400 value for HQII is routinely exceeded during the time period shown in the figure. On the other hand, there have been instances that TTCs have fallen—in particular, the NY import capabilities show a large decrease in Fall 2011, when a severe snowstorm struck the Northeast U.S. and caused many transmission and distribution system outages.

FIGURE 11. TOTAL TRANSFER CAPABILITY, MONTHLY AVERAGE, 2010-2013



I compare these TTCs to scheduled interchange data in the figure below. Thus, Figure 12 shows average hourly net availability to move additional power. Flows can be scheduled to meet contracted demands and/or to take advantage of relatively high prices (during higher demand and higher priced hours). Thus, I would expect greater availability during off-peak hours and during shoulder seasons when load and prices are low compared to winter and summer peak conditions in New England. Moreover, I would expect flows to increase as prices in New England rise relative to prices in other regions, which has appeared to be the case with the increase in net inflows of power (probably due to the relatively higher prices of natural gas delivered to New England generators).

FIGURE 12. AVERAGE NET TRANSFER CAPABILITY, 2010-2013



The table below shows summary statistics from the data in Figure 12.

TABLE 7. SUMMARY STATISTICS FOR AVAILABLE TRANSFER CAPABILITY, 2010-2013

		Highgate	HQ	NB	NY (Roseton)	Total
Average	MW	27	312	582	1,028	**1,949**
Max	MW	225	2,000	1,000	1,400	**4,418**
Min	MW	-	-	-	-	**-**
Total	**MWh**	**953,449**	**10,952,113**	**20,408,339**	**36,031,968**	**68,345,869**

The available transfer capability data shows that 1,949 MW were still available on average over the 2010-2013 time period over the four interfaces shown in the table. The Highgate facilities feature the fewest hours with available reservations during this time period. Both HQ and NB feature a relatively wide range of availability. NB has total available transfer capability over this time period greater than the HQ Phase II facilities, despite being much smaller in size, which may be largely due to additional delivery constraints in New England.

In total, over the past four years, almost 68,000,000 MWh or 68 TWh of additional energy could have been delivered through the four interfaces shown above. Of course, there are a number of additional requirements (including contracting reservation owners, arranging for a buyer, and synchronizing energy production with available transmission) to move power, and this analysis should be not be used to forecast the actual potential additional flow that could occur over this time period. Rather, the analysis shows that space is indeed available at various times should HQD choose to move additional renewable energy (and RECs) into New England. Unlike energy, REC values do not vary based on the time of day, hence off-peak REC deliveries add proportionally more value to off-peak energy revenues than to on-peak energy revenues. Assuming power is being generated and can be delivered to the border, there appears to be available transmission reservations during this time period.

Moreover, Figure 12 and Table 7 showed data for available transfer capability but there are parties that currently own or have access to reservations on the facilities analyzed above. Thus, exempting long-term, firm commitments to deliver power (which appear to not be relevant for Québec), there may be reservations that could be shifted to accommodate flows of power that would be eligible for premium REC markets. Based on forecasted REC values discussed in the prior chapter, it is evident that delivery of RECs at a price of more than $60/MWh adds significant value to energy market revenues (see energy prices shown in Figure 2),which are expected to remain muted over the near future, except during peak winter load conditions).

Finally, HQD mentions the possibility of additional transfer capability into New England may be possible which would permit additional REC deliverability.

7. CONCLUSIONS

Sale of energy products, in particular environmental attributes in premium REC markets can generate significant revenues to HQD and thus reduce ratepayer cost of purchases of premium-market-eligible generation. These revenues are much greater than any revenues that could be generated from HQD's participation in voluntary REC markets, as currently contemplated in the procurement plan. Though there is a number of requirements and processes that needs to be followed to enable sales into New England's premium REC markets, none of them are onerous or pose serious barriers for increased participation by HQD in these markets.

At the very least, I have not found in HQD's evidence filed with the Régie adequate explanation for their proposed strategy with respect environmental attributes. HQD points to the reasoning used in the 2011-2020 supply plan, but that logic did not prove to be correct (and is clearly not applicable to current and anticipated attribute market conditions). Market prices were elevated in 2011-2013 and availability of transmission capacity was actually greater in 2011 than in more recent times. Moreover, HQD's existing contracts with its premium-REC-eligible generators provide the option for HQD to request that the sellers of renewable power register and apply for certification to sell into premium markets. Apparently, HQD did not pursue any of the steps necessary to at least be ready to sell into the premium REC markets and, as a result, did not take advantage of the increase in REC prices.

For the current supply plan, HQD could take steps to at least be ready to delivery premium RECs to New England. Such a step would involve minimal cost and provide HQD with the potential to tap into these markets in a matter of months. As described in the report, premium REC prices are expected to remain elevated. Indeed, the lack of entry into the market, including the lack of HQD's participation in the market, has led to state action to complete central procurement efforts to fill the gap. This lack of entry to the market has led to elevated prices, which has increased concern among some New England states. In sum, the longer that HQD waits to access these markets, the likelihood of opportunities for additional revenues over the near term will diminish to the detriment of its rate payers. HQD could immediately initiate actions to avoid missing out on opportunities to extract value from the renewable facilities it has under contract, which has been the case since the prior supply plan.

Over the longer term (towards the end of the current supply plan's period), the demand for premium RECs is strong and contains potential for HQD to generate significant revenues that can be used to reduce ratepayer costs that have been used to support renewable generators in Québec. For the benefit of its ratepayers, HQD could investigate ways it can better manage the sale of energy products and particularly environmental attributes from these facilities as part of its supply plan and take action to monetize their value.

APPENDIX A – RESUME

Alvaro E. Pereira, Ph.D.

Managing Consultant

Alvaro Pereira is an accomplished energy professional with 20 years of experience in economic, technical, and policy analysis with expertise in rate design, power markets, and climate change policy. Dr. Pereira joined La Capra Associates in 2008, following nearly a decade with the Massachusetts Department of Energy Resources as the head of a group responsible for economic and technical analyses of policies, programs, and regulatory filings. At La Capra Associates, he works in a variety of areas including procurement, renewable energy project analysis and pro forma development, and analyses of energy and capacity market rules, prices, and performance. Dr. Pereira is an experienced expert witness, having testified on various occasions before regulatory commissions, and he has provided expert-witness research and testimony in cases involving costs and benefits and environmental quality. Dr. Pereira also has expertise in rate design and analysis, demand resources, and economic impact modeling and forecasting. He has an M.S. in Transportation and a Ph.D. in Urban and Regional Economics and Studies, both from M.I.T., and two bachelor degrees in Economics and Finance from UMass Amherst.

SELECTED PROFESSIONAL EXPERIENCE

Renewables/RGGI

Co-authored study of economic costs and benefits of solar (SREC-II program) in Massachusetts. Applied modeling framework that analyzed wholesale market, avoided transmission and distribution, and avoided generation benefits.

Co-authored separate analyses of RPS investments, large offshore wind, and solar expansion scenarios in New York. Led team that analyzed rate, environmental, and cost-benefit impacts of different solar buildouts. Developed modeling interface among pro forma, energy, and economic impact models.

Co-authored report on the hedge value of offshore wind resources in Maryland. Work applied portfolio theory by examining offshore wind's price variability compared to non-renewable generation options and considering wind's price covariance with fossil-fueled generators to document price-related benefits.

Provided analytical support for rate impact calculation of offshore wind legislation for the Maryland Energy Administration.

Provided advice regarding market price/modeling and economic cost/benefit analysis to the New Jersey Board of Public Utilities in support of development of rules and regulations for the Offshore Wind Renewable Energy Credit (REC) program.

Co-authored report on Delmarva Power's request for approval of solar REC contracts for the Delaware Public Service Commission Staff. Examined financial feasibility and underlying revenue/cost data of a 10 MW solar farm for reasonableness and public interest.

Currently providing NEPOOL-GIS third-party verification services for NEPOOL-GIS for hydroelectric, landfill gas, solar, and wind facilities.

Provided technical and market advice and wrote portions of the proposal for a 220-MW Maine-based wind farm submitted to the Massachusetts' utilities request for proposals for long-terms supply and RECs. Played a similar role in support of registration of an 80-MW Vermont-based wind farm for qualification in the ISO-NE forward capacity market.

Evaluated the financial feasibility of a proposed offshore wind installation and shrouded turbine wind facility in Hull, Massachusetts, as well as for solar installations for a number of clients. Forecasted and analyzed different revenue streams (energy, renewable energy certificates, and capacity) and examined financing options, while incorporating new federal and state incentive programs and policies.

Researched forward capacity market rules in New England regarding qualification requirements, auction administration, financial assurance, and resource availability adjustments as regards to renewable resources and other intermittent generators. Co-authored study that examined the feasibility and impacts of restricting imports of renewable generation into New England and for participation in the Massachusetts RPS.

Co-authored Massachusetts regulations for state auction of Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. *Note:* Massachusetts was the first state to draft regulations related to auctioning of carbon allowances.

Supervised the economic modeling and impact analysis of changes in regional energy systems, including the expansion of renewable and DSM activities, due to the establishment of a regional cap and trade system for carbon emissions through the RGGI program. This work led to ratification and approval of the cap and trade system by a majority of the Northeastern states.

Procurement/Market Analysis

Providing ongoing procurement support (buy and sell sides) to a number of clients throughout the Northeast, including Amtrak, the Massachusetts Water Resources Authority, and the Massachusetts Port Authority. Supported and conducted numerous electricity solicitations, ranging from 5 MW to 100 MW. Also providing expert advice regarding participation (load and generation assets) in wholesale energy, capacity, REC, and reserve markets.

Forecasted capacity market prices (in New England, New York, and PJM) for use in project evaluation and impacts on retail rates. Included discussion of bidding strategies for generators given different projections for auction clearing prices. Forecast work included determination of future implementation levels of energy efficiency and other demand-side resources as capacity resources.

Participated in statewide procurement of electric, gas, and petroleum products for Commonwealth of Massachusetts agencies and facilities. Forecasted gas and electric prices for use in procurement decisions.

Managed procurement of long-term renewable electricity for use by Massachusetts agencies and facilities. Calculated and compared costs of long-term renewable power versus short-term brown power procurements to inform state agency budgets.

Managed technical assistance to municipalities seeking to aggregate their customers for purposes of procuring electricity.

Demand Resources

Reviewed the energy efficiency plans and underlying testimonies of PPL and PECO in proceedings before the Pennsylvania Public Utility Commission in support of testimony evaluating the costs and benefits of plan components.

Designed time-of-use rates for municipal utilities in order to provide incentives for reductions during summer peak. Calculated potential impacts of dynamic rates on both capacity payments by the utilities and bill savings to customers.

Enrolled demand-side resources (energy efficiency and distributed generation) of various Massachusetts agencies into the New England Forward Capacity Market. Wrote monitoring and verification plans for a variety of demand-side resources.

Lead author on annual report for Massachusetts that chronicled the cost-effectiveness, customer allocation of funds, short and long-term savings goals and the development of a competitive market for energy efficiency services.

Developed modeling approach and methodology to estimating the energy system and economic impacts of DSM activities conducted in the Commonwealth.

Rates and Regulation

Reviewed demand forecasts underlying Columbia Gas of Massachusetts' 2013 Demand and Supply Forecast filing.

Conducted load forecast for Blackstone Gas Company in support of their 2012 Long Range Supply (or Integrated Resource) Plan. Submitted written testimony in support of forecasts of customer counts, sendouts (design day and normal monthly), and usage per customer. Conducted forecasts under a variety of weather and design day criteria.

Reviewed load forecasts underlying Rocky Mountain Power's request to increase electric service rates. Analyzed methods, data sources, and assumptions. Conducted alternative forecasts of customer counts, sales per customer, and overall sales.

Provided research and wrote portions of the Maryland Energy Administration's comments to the Maryland Public Service Commission proceeding on RFPs for generation capacity resources under long-term contracts (Case No. 9214).

Assisted in writing expert testimony assessing the impacts of wholesale congestion costs on Pennsylvania default service customers. Investigated market mechanisms for financial transmission rights and made recommendations concerning procurement of relevant hedging products.

Reviewed Vermont state load forecasts for impacts of energy efficiency. Analyzed alternative functional forms and modeling assumptions regarding the role of energy efficiency in peak shaving.

Policy and Planning Analysis

Co-authored evaluative study of electric industry restructuring efforts in Massachusetts and New England. Examined the impacts of restructuring on market manipulation and consolidation and its effects on electricity costs. Reviewed the status of competition of generation and retail electric supply and discussed the prognosis for residential customer participation in retail markets.

Authored study of strategies to reduce Maine's dependence on oil. Reviewed current and forecasted oil usage across all energy sectors and uses and the costs of different strategy choices. Study findings were used to inform legislative and policy recommendations.

Analyzed and computed national and regional generation, transmission, and distribution infrastructure capital investment needs. Advised on the modeling and impacts of failure to meet these investment needs on the economy.

Authored study for the Massachusetts Department of Energy Resources regarding the costs and benefits of municipalization of utility-owned distribution and non-PTF transmission assets. Examined potential impacts on reliability, utility operations and revenues, municipal taxes, electricity rates, financing, energy efficiency programs, and low-income customers.

Conducted analysis of state energy entities in Connecticut in terms of structure and functional roles. Performed survey of other states and compared and contrasted alternative structures with existing state structure. Wrote sections of Phase I report describing results of this work. Contributed to Phase II report that recommended changes to agency structure and roles, including analysis of a power authority option.

Contributed to all phases of proceeding before Connecticut Siting Council regarding the 2008 Forecasts of Load and Resources. Prepared discovery and wrote comments to draft report. Recommended changes to promote consistency between forecast and 2008 Integrated Resource Plan that was in review and to clarify assumptions underlying different utilities' forecast for conservation and load management programs

Wrote appendix detailing existing procurement processes and programs available to Connecticut policymakers. Appendix served as component of La Capra Associates' review of the 2008 Integrated Resource Plan submitted by the utilities.

Expert Witness

Testified before the Rhode Island Public Utilities Commission on behalf of the Rhode Island Division of Public Utilities and Carriers regarding Recommendations for 2014 Distributed Generation Classes, Ceiling Prices, Targets, and Standard Contracts. *(Dockets No. 4277 and 4288, February 26, 2014.)*

Testified (direct and surrebuttal) before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General regarding the petition and revised petition for approval of the sale of New England Gas Company's assets. *(D.P.U. 13-07, May 31, 2013.)*

Testified (direct) before the Pennsylvania Public Utilities Commission on behalf of the Pennsylvania Office of Consumer Advocate regarding the petition submitted by People's TWP LLC for approval of their 2013 Purchased Gas Cost Filing. *(Docket No.R-2013-2341604, March 6, 2013.)*

Testified before the Rhode Island Public Utilities Commission on behalf of the Rhode Island Division of Public Utilities and Carriers regarding Recommendations for 2013 Distributed Generation Classes, Ceiling Prices, and Targets submitted by the Rhode Island Office of Energy Resources. *(Docket No. 4288, January 11, 2013.)*

Testified (direct) before the Pennsylvania Public Utilities Commission on behalf of the Pennsylvania Office of Consumer Advocate regarding the petition submitted by Citizens'

Electric Company and Wellsboro Electric Company for approval of their proposed joint default supply service plan. *(Docket No. P-2011-2307827, 2307931, August 21, 2012.)*

Testified (direct and surrebuttal) before the Pennsylvania Public Utilities Commission on behalf of the Pennsylvania Office of Consumer Advocate regarding the petition submitted by PPL Electric Utilities for approval of its proposed reconciliation and competitive transition riders for default supply service. *(Docket No.P-2011-2256365, November 2, 2011.)*

Testified (direct) before the Delaware Public Service Commission on behalf of the Delaware Public Service Commission Staff regarding the application of Delmarva Power and Light Company for approval of qualified fuel cell provider project tariffs. (*PSC Docket No. 11-362, October 18, 2011.)*

Testified (direct) before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General regarding the joint petition for approval of a merger between NSTAR and Northeast Utilities *(D.P.U. 10-170, May 20, 2011*.)

Testified before the Maryland Public Service Commission on behalf of the Maryland Energy Administration regarding reliability pricing model and the 2013/14 delivery year base residual auction results *(Administrative Docket PC22, October 15, 2010.)*

Testified (direct) before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General regarding the request for a change in distribution rates by National Grid *(D.P.U. 10-55, June 28, 2010*.)

Testified (direct) before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General regarding the proposed solar program filed under the Green Communities Act by National Grid *(D.P.U. 09-38, August 2009.)*

Testified (direct) before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General regarding the proposed solar program filed under the Green Communities Act by Western Massachusetts Electric Company *(D.P.U. 09-05, July 2009.)*

Testified before the Massachusetts Department of Public Utilities on behalf of the Massachusetts DOER regarding rate structures that will promote efficient deployment of demand resources. *(D.P.U. 07-50, October 2007.)*

Testified (direct and surrebuttal) before the Massachusetts Department of Telecommunications and Energy on behalf of the Massachusetts DOER regarding the performance-based rates and earnings sharing mechanism proposed by Bay State Gas Company. *(D.T.E. 05-27, July 2005.)*

Testified (direct) before the Massachusetts Department of Telecommunications and Energy on behalf of the Massachusetts DOER regarding the appropriateness of standby distribution rates proposed by NSTAR Electric. *(D.T.E. 03-121, March 2004.)*

EMPLOYMENT HISTORY

La Capra Associates, Inc. Boston, MA
Managing Consultant *June 2011 – Present*
Senior Consultant/Consultant *2008 – May 2011*

Massachusetts Division of Energy Resources Boston, MA
Manager, Energy Supply & Pricing Group (December 1999 – 2008) *1999 – 2008*

Senior Economist (March 1999 – November 1999)

Massachusetts Institute of Technology Cambridge, MA
Lecturer in the Department of Civil & Environmental Engineering 1998 – 1999

Independent Consultant Somerset, MA
Economist and Data Modeler *1998*

Massachusetts Institute of Technology Cambridge, MA
Visiting Lecturer in the Department of Urban Studies and Planning 1997 – 1998
Research Associate, Department of Urban Studies and Planning (September 1991 – August 1997)
Research Assistant, Department of Civil Engineering (September 1989 – August 1991)

EDUCATION

Massachusetts Institute of Technology Cambridge, MA
Ph.D., Urban and Regional Economics and Studies *1997*
M.S., Transportation *1991*

University of Massachusetts Amherst, MA
B.B.A., Finance (Summa Cum Laude) *1989*
A.B., Economics (Summa Cum Laude) *1989*

PROFESSIONAL TRAINING & SKILLS

Proficient in STATISTICA, Forecast Pro, and comparable statistical analysis programs, tsMetrix and comparable neural network programs, REMI and comparable economic-modeling packages, ENERGY2020 and comparable energy market simulation modeling programs. Familiar with C programming language and Visual Basic. Fluent in Portuguese. Working knowledge of Spanish.

ADDITIONAL PUBLICATIONS, PRESENTATIONS & CONFERENCES

"Renewable Energy Development in the Shale Era." Presentation to the AQPER Colloque 2014, Québec Association for the Production of Renewable Energy, February 20, 2014, Québec City, Canada.

"Forward Capacity Market as Swiss Army Knife." Presentation to the 11th Annual Power Markets Conference: Strategic Planning for New England's Power Markets, Northeast Energy and Commerce Association, October 24, 2012, Westborough, MA.

"Shale Gas and Renewable Energy: Friends or Foes?" Presentation to Air & Waste Management Association—New England Section Fall 2012 Conference, October 12, 2012, Framingham, MA.

"RGGI Auction Process" Presentation to RGGI Implementation at the State Level: Regulations, Requirements & Strategies, Northeast Energy and Commerce Association Workshop, June 19, 2008, Boston, MA.

"Electricity Price, Reliability and Markets Report 2005." A Report to the Great and General Court on the Status of Restructured Electricity Markets in Massachusetts. Commonwealth of Massachusetts, December 2006 (lead author).

"Electricity Price, Reliability and Markets Report 2002-2004." A Report to the Great and General Court on

the Status of Restructured Electricity Markets in Massachusetts. Commonwealth of Massachusetts, Spring 2006 (lead author).

"Meeting New England's Future Natural Gas Demands: Nine Scenarios and Their Impacts." A Report to the New England Governors, Boston, Massachusetts, March 2005 (lead author).

"2002 Energy Efficiency Activities." An Annual Report to the Great and General Court on the Status of Energy Efficiency Activities in Massachusetts. Commonwealth of Massachusetts, Summer 2004 (lead author).

"2001 Energy Efficiency Activities." An Annual Report to the Great and General Court on the Status of Energy Efficiency Activities in Massachusetts. Commonwealth of Massachusetts, Summer 2003 (lead author).

"Economic Development of the Boston Harbor: Informing the Process." Written for Boston Harbor Conference, May 11, 1998.

"Regional Economic Modeling and the REMI Model Evaluation." Commissioned Manuscript for Appalachian Regional Commission, September 4, 1998 (co-author).

"Transportation Policy and the 1990 Clean Air Act." In Research in Urban Economics, New Urban Strategies in Advanced Regional Economies, 1996 (co-author).

"Regional Rail Planning in New England." Proceedings of the Transportation Research Board, 1994 (co-author).

"Meeting New England's Future Natural Gas Demand." Presentation to the Center for LNG & U.S. Energy Association, LNG Conference, June 16, 2005, National Press Club, Washington, D.C.

"The Intradependence of Natural Gas & Electricity Markets in New England." Presentation to Northeast Energy Efficiency Council and the Association of Energy Service Professionals Annual Conference, October 25, 2004, Marlboro, Massachusetts.

"Retail Treatment of Zonal Generation Prices in Massachusetts." Presentation to the Massachusetts Electric Restructuring Roundtable, September 13, 2002, Boston, Massachusetts.

"Future of Retail Competition in Massachusetts, Just the Facts, Massachusetts." Presentation to the Massachusetts Electric Restructuring Roundtable, January 18, 2002, Boston, Massachusetts.

"Developing an Effective Demand Response." Presentation to the Electric Power Supply Association State Issues and Membership Meeting, July 24, 2001, Washington, D.C.

"Emergency Prevention, Monitoring, and Communication." Presentation to the New England Disaster Recovery eXchange Meeting, June 13, 2001, Boston, Massachusetts.

"Logistics and Transportation Use in the Chicago Metalworking Sector: Implications for Transportation Planning." Presentation to the 43rd North American Meeting of the Regional Science Association International, November 16, 1996, Washington, D.C.

"A Study of STAA Truck Safety in New England." Presentation to a Conference of the New England Transportation Infrastructure Research Programs, June 14, 1993, The New England Center, Durham, New Hampshire.

APPENDIX B – PREMIUM REC PRICE FORECAST (CONFIDENTIAL)

[FIGURE FILED CONFIDENTIALLY]