Modifying the Old Grid to Accept Clean Power: The Next Step in the Greening of New England

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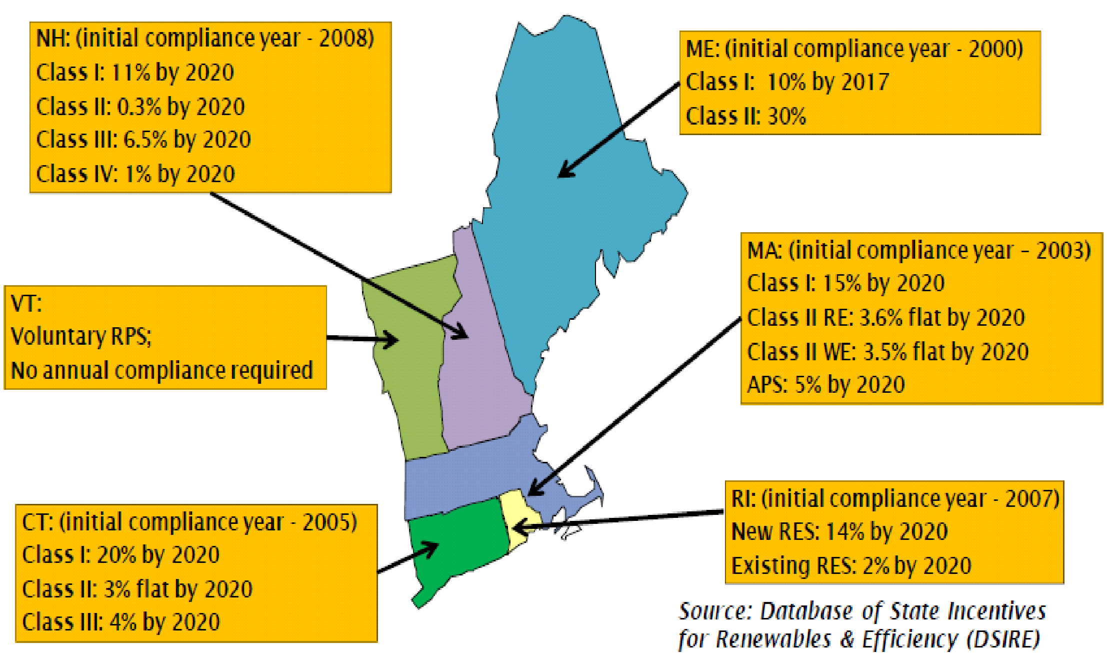
Electric transmission projects determine – for better or for worse – how we get power into our homes, where it comes from, how much it pollutes the environment, and how much it costs. Decisions made generations ago still determine how dependent we are on the various sources of electric energy. We've spent tens of billions of dollars on a Grid into which oil, coal, nuclear, hydro, and natural gas plants could "plug and play." Only in the last ten years or so – "recently" in infrastructure time – have we become aware that we built a Grid for dirty power.

Beginning in the early 2000s, the state governments of New England resolved to clean up the power supply system. Slowly and somewhat painfully, the region has finally begun to get away from dirty power. Oil is practically gone from the power system, coal is in its dying days, even nuclear (which is carbon free but imposes other environmental risks) is on its way out. What the New England bulk power system will rely on in the future is natural gas, hydroelectricity, and the “fuels from heaven:” wind and solar electricity. Each of these has its own challenging relationship with the old Grid.

Natural gas is in many ways ideal for generating electricity. From a carbon perspective, while it is far from perfect, it’s a big improvement over oil and coal. Natural gas pipelines are buried, and out of sight means out of mind for the general public. The pipelines can often be brought to the same places where the old oil and coal plants were built. For example, the coal-fired power plant that used to operate in Salem, Massachusetts could be torn down and replaced with a gas-fired plant. These big power plants consume so much gas it’s often economic to build several miles of new pipe to connect them to a major gas pipeline nearby.

But no one wants to become completely dependent on natural gas. Its price has historically been extremely volatile, and while it’s cheap today, no one can predict whether it will be cheap in 5, 10, 20 or 50 years. That’s why there is a consensus among those who run and regulate the power system that efforts must be made to diversify New England’s sources of power supply. That diversification is important not only for its own, portfolio-strengthening sake, it’s also important to achieve the renewable portfolio goals to which most New England states remain strongly committed. As seen in the chart below, taking the New England region as a whole, all the states except Vermont have legislated that clean electricity should provide 10-20% of the total electric power, up from 4-10% today. Some states, like Vermont, Maine and New Hampshire, already use even higher amounts of what each regards as renewable energy (imported large-scale hydro and/or biomass from the abundant forestry industries). For Connecticut, Massachusetts and Rhode Island, who are less keen on large-scale dependence on either imported hydro or biomass, the commitment to clean energy means a lot of new wind and solar resources.



London Economics Survey of New England States Renewable Portfolio Standards circa 2011

Unfortunately, the Grid was not built to give these sources the same “plug and play” convenience that natural gas enjoys. The bulk of New England’s wind resources are in northern Maine, the main source of hydroelectricity is Canada, and most of the solar energy generated in the future will not be in the bulk system, but in small, retail installations within the electric distribution systems of villages, towns, and cities.

Solar energy is growing fast, and some argue it should meet the lion’s share of the future demand for electricity. Appealing as that is, it remains impractical. New England is not Arizona, and while solar power will be a very important part of the power system, it can’t be the baseload source of power.

Hydroelectric energy is also appealing, and New England’s governors have recently reiterated their interest in buying more from their Canadian neighbors, especially Quebec and (later in this decade) Newfoundland (via Nova Scotia and New Brunswick).Unfortunately, the Grid was not built to accommodate such large new infusions of hydro power. So, large new transmission lines have been proposed to bring that power to market. Some of these proposals are for “all imported hydro all the time,” and others are for a combination of wind and hydro (basically, when the wind blows, it gets to use the transmission line; when it doesn’t blow, the hydro can use it).

The development of large-scale wind is essential to create a desirable, mixed portfolio of renewable energy. Experience in the last ten years has shown that there will be a lot of small wind installation on a town-by-town basis, and a few medium-to-large-size wind farms have been built in Maine, New Hampshire and Vermont. Really large-scale wind, however, is available only in more remote parts of Maine, northern New York, the Canadian Maritimes, and the waters of the Atlantic. Again, the old grid wasn’t built to connect northern Maine or offshore wind to southern New England, so harvesting this wind inevitably requires building transmission lines.

New transmission projects are seldom popular additions to the region’s infrastructure. Nevertheless, they are essential. The question is not if these new lines are necessary: they are. The question is which competing transmission proposals should be selected to proceed, since each of them requires, in one form or another, long-term commitments from electric utilities and their customers. There is a choice of projects, and the selection of a major addition to the Grid is a classic example of how public policy determines the deployment of private capital. Unlike highways, electric transmission projects are not built with tax dollars, they are built with electric ratepayer dollars. Because transmission is a natural monopoly, it is regulated by state commissions, as well as by the Federal Energy Regulatory Commission (FERC). So the construction of new transmission lines in new corridors starts as an act of policy. It is elected representatives who ultimately create the conditions in which particular electric infrastructure projects can go forward, or not.

In New England, there are six major proposals to add substantial new capacity to the Grid for the sake of bringing more clean energy into the region. Which ones are selected will determine – for decades to come – the kind of clean energy New England will bring into its bulk power system.

1. **The Northern Pass**: a 1200MW mostly overhead high voltage direct current (HVDC) project that will enable imports of power from the province of Quebec, down the length of New Hampshire,

to Franklin, NH, from where additional Grid upgrades would bring most of the power into the "Mass Hub," the heart of the southern New England market. Northeast Utilities and NStar are the sponsors, working with Hydro Quebec as a supplier.

2. **The New England Clean Power Link:** a 1000MW HVDC project that will also enable imports of power from the province of Quebec, down the length of Vermont using Lake Champlain as a conduit for a buried cable, to one of three possible connection points in southern Vermont, from where the power flows into the "Mass Hub." Transmission Developers International is the sponsor.
3. **The Green Line 1200:** a 1200MW hybrid land-and-sea HVDC project that will enable up to 1200MW of wind in Northern Maine, "firmed up" by imports of power from the provinces of New Brunswick, Quebec, or Newfoundland (via) Nova Scotia, buried under the ocean floor from Searsport, Maine to a landfall near Lynn, MA, from which a buried cable would inject the power into the Wakefield, MA substation, in the heart of the Northeast Massachusetts ("NEMA") market and into the "Mass Hub." New England Independent Transmission Co. LLC is the sponsor.[1]
4. **The Grand Isle Intertie**: a 400MW buried high voltage alternating current (HVAC) project that will enable up to 400MW of wind in New York, "firmed up" by imports of power from New York, transiting a short distance from west to east under the bottom of Lake Champlain, from Plattsburg, NY to Burlington, VT. Anbaric Transmission is the sponsor.
5. **The Northeast Energy Link**: a 1200MW HVDC project from the Orrington (near Bangor), Maine area to Tewksbury, Massachusetts. The NEL proposes to bury the transmission cable alongside Interstate 95. National Grid and Emera are the sponsors.
6. **Offshore Wind:** The 420MW Cape Wind and succeeding offshore wind projects. Cape Wind has arranged its own transmission connection (a relatively modest 10-mile connection to the Grid on Cape Cod). As and when other, and potentially much larger, projects are developed, it is unlikely each of them can find a similarly efficient path to market. More likely, a master offshore transmission project will have to be developed that would gather all the offshore wind (except Cape Wind) and bring it to market using a series of 1000MW HVDC connections. Such offshore connectors are being built in Europe that will be models for the US offshore wind industry.

These six transmission proposals are not just projects, they are infrastructure that will determine to a large extent how New England meets its bulk renewable energy supply needs. The decision on which, if any, to build is a once-in-a-generation turning point in the long life of New England's power system.

The six projects represent four different strategic paths: (1) transmission to Canadian resources; (2) transmission to offshore wind; or (3) transmission that harvests both onshore wind and Canadian imports. If none of these are chosen (if New England decides to build no new transmission to access large-scale renewables), that also constitutes a strategy: (4) doing nothing to access large-scale clean energy sources.

[1] Anbaric is a partner in NEITC.

These strategies are not always going to be mutually exclusive: over the coming decades, New England may deploy one strategy after another. But given the constraints on the number of dollars states are willing to spend on transmission, only one strategy is likely to be chosen today, followed by another five, ten, or twenty years from now.

A Decision Not To Build Clean Energy Transmission

Given that this is a major governmental decision, and that governments often like to avoid such decisions, it's quite possible none of the projects will be selected to move forward. Even though the construction of a bulk transmission line is often portrayed as a private sector action, new transmission requires the support of government officials and regulators. Thus, it is entirely possible none of the projects will get built.

In this case, it is virtually certain that the Renewable Portfolio Standards passed by various state legislatures a decade ago would not be achieved. Advocates of solar and other forms of distributed energy claim that those resources can fill the void, but it simply is not possible. While solar farms, micro-wind turbines, and continued enhancements in building efficiency will continue to make contributions to RPS compliance, they are simply too small to meet the bulk power needs: only wind and hydro can play that role.

So the failure to let any of the transmission projects move forward ensures failure to meet RPS standards and all they stand for in the large climate change battles to come. Moreover, without transmission to support wind and hydro projects, the supply hole created by the retirement of nuclear, coal, and oil plants can only be filled by natural gas. Thus, without electric transmission of clean energy, there will have to be more transmission of natural gas to fuel the gas-fired power plants that will replace the departing coal and nuclear facilities. *It is ironic that the absence of electric transmission projects virtually guarantees the expansion of natural gas pipelines*.

New England is already fated to become much more dependent on natural gas. And why not? It's an affordable, relatively (in comparison to coal and oil) clean source of electricity. But it is not "clean" energy. Advocates of natural gas also often claim it should be the fuel of choice because it is inexpensive. And so it is, for now. But its history is of extreme price volatility, and there's no reason to believe prices will be less volatile in the future. Natural gas is firmly embedded in the commodity trading culture, which draws its very lifeblood from volatility.

Meanwhile, gas advocates seldom mention that onshore wind costs have declined dramatically over the last decade. Indeed, a November 2013 bulletin from one of Wall Street's leading power sector analysts remarked that "[T]he economics of wind continue to improve—and have continued to do so of late… capital costs having declined to ~$1,700/kW and net capacity factors of ~45% and north of 50% depending on the location, essentially approaching those of combined cycle natural gas plants. As [wind] farms become more efficient/predictable and grow in scale, we see O&M costs/MWh declining."[2] In

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[2] Email from Julien Dumoulin-Smith from banking giant UBS, November 15, 2013.

New England, recent awards in competitive RFPs for large scale wind were given to projects at $70-$80 per MWh. Future RFPs for even larger wind procurements may result in prices even lower than that.

If wind is competitive with gas at today's rock-bottom gas prices, it will be even more competitive when natural gas returns to one of its periodic cycles of high prices (which could happen, for example, if US natural gas exports grow as many believe they will).

Selecting none of the electric transmission alternatives, therefore, is certain to mean New England will fail to meet its legislated RPS goals, and is likely to mean New England will not avail itself of a fuel – wind – that has become competitive with natural gas even at today's low gas prices.

The economics of large-scale hydro are more mysterious. There is evidence that the average cost of large scale hydro in Quebec is near $80/MWh. According to the US Department of Energy, the levelized, average cost of large-scale hydroelectricity in North America is $90/MWh.[3] Opponents of the Northern Pass project make the following claim: the levelized investment cost for the additional hydropower in Quebec is in the range of $100/MWh, depending on assumed financing costs; the cost of the transmission expansion in both Quebec and New Hampshire results in an average cost for all transmission facilities of about $40/MWh. Thus the all-in capital cost of the power delivered into New England should be above $140/MWh.[4]

In other transactions, however, Hydro Quebec sold power to Vermont utilities at a price starting (in 2012) of $58/MWh, which is then adjusted annually.[5] In that case, the transmission infrastructure was already in place, so it's reasonable to assume that this price reflected mostly the price at which Hydro Quebec was willing to sell electric energy under a long-term contract. In the Northern Pass discussions, it has sometimes been suggested that Hydro Quebec would be willing sell its power at a percentage (presumably, less than 100%) of the market price in New England. Since the market price today is less than $50/MWh (and thus, considerably lower than the estimated average delivered cost of hydro power), one can presume that Hydro Quebec is employing its right to sell power below its average cost.[6]

The issue of wind versus hydro versus natural gas future power costs, therefore, is not as simple as it may seem. The economics of wind appear to be improving, and are best in very large wind farms. The economics of some large-scale hydro deals (such as the one Hydro Quebec did with Vermont) were also attractive and it remains to be seen what long-term prices Hydro Quebec, or the hydro generators in Newfoundland (when those projects come on-line), would bid into a competitive, long-term RFP.

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[3] From http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

[4] From a study by the PA Consulting group financed by the New England Power Generators Association, "Electricity Market Impacts of the Northern Pass Transmission Project." From http://www.nepga.org/files/library/pa_report_electricity_market_impacts_of_the_northern_pass_transmission_project_june_11_2012.pdf.

[5] http://psb.vermont.gov/sites/psb/files/orders/2011/7670FinalOrder.pdf.

[6] This is economically rational under the sunk-cost doctrine if Hydro Quebec has already sunk capital into expansion of its hydro generating facilities, and those facilities are incapable of monetizing all of that power in the absence of transmission projects like Northern Pass.

The conclusion of this line of thinking is that the decision NOT to build clean energy transmission avoids a known cost – the cost of electric transmission. But it also exposes New England to others costs: the cost of building additional natural gas transmission, the cost of future natural gas price volatility, and the cost of non-compliance with RPS commitments. Moreover, being utterly dependent on electricity from natural gas because the region did not want to build electric transmission facilities to clean energy sources may be very costly if problems emerge in either the supply or physical delivery of gas to the region. In essence, this is a classic portfolio diversification issue: when the prices of assets in the portfolio are uncertain, there's real value in having a diverse portfolio.

The Renewable Energy New England States Say They Want

If New England must invest in transmission to achieve its transition to a cleaner energy economy, which of the three transmission strategies (transmission to Canadian resources, transmission to offshore wind, and/or transmission that harvests both onshore wind and Canadian imports) makes the most sense? To conduct that analysis, it's necessary first to review what New England states have said they want in terms of clean electric energy.

Vermont

Vermont is the only New England state that does not have a legislated Renewable Portfolio Standard, yet it still has had a largely carbon-free electricity portfolio. In the past, most of its electric energy came from the Vermont Yankee nuclear plant and from Hydro Quebec. With the closure of Vermont Yankee, the question of where Vermont will get its bulk power is uncertain. While New England currently has a surplus of generating capacity, and therefore Vermont utilities can buy both capacity and energy at reasonable prices in the spot market, Vermont's utilities have tended to be long-term buyers of capacity, and have shown an appetite for imported hydro far more than other New England states.

Indeed, in an unusual twist, Vermont utilities were given an incentive in 2011 to help HQ persuade other New England states to recognize its hydroelectric power as eligible to receive full credit towards Renewable Portfolio Standards. This transaction was described as follows by an executive participating in the negotiations:

> *By late March 2010 – after the announcement that Vermont utilities would buy 218 to 225 megawatts of energy from Québec for twenty-six years with some deliveries starting in 2012 and continuing until 2038 – the Vermont Legislature began in earnest to debate changes in the Vermont law on treatment of large hydro as renewable. The legislation moved with unusual speed through the Vermont Legislature primarily because of a provision in the Vermont utilities' contract with Hydro-Québec that provides that Vermont consumers will share in any financial benefits Hydro-Québec realizes by virtue of the environmental attributes associated with the energy delivered by Hydro-Québec into the New England market. … The willingness of Hydro-Québec to share the financial benefits it may garner as a result of being able to sell the environmental attributes associated with the energy it produces and exports gave a tremendous boost to the legislative effort to amend Vermont's definition of renewable energy with respect to energy produced by large hydro facilities. In fact, the Vermont House of Representatives, by a*

vote of 129 to 3, and the Vermont Senate, by a unanimous vote, overwhelmingly approved H. 781…. [7]

Connecticut

Connecticut conducted a thorough evaluation of its clean energy strategy in 2013. The House and Senate passed "An Act Concerning Connecticut's Clean Energy Goals, as amended," on May 28, 2013, including some interesting revisions in the RPS standards and compliance efforts. As summarized by the Day Pitney Law firm:

> *The legislation permits the use of large-scale hydropower for RPS compliance in certain circumstances when the RPS could not otherwise be met by Class I renewable energy sources within the state. Large-scale hydropower will include facilities with a generating capacity of more than 30 MW that began operation on or after January 1, 2003, and are located in or adjacent to the New England Power Pool geographic region (which would include the New York, Quebec and Maritimes electric control areas) and in certain electric control areas to the north of that region (e.g., in Newfoundland and Labrador).*
>
> *For each calendar year beginning on January 1, 2014, large-scale hydropower will be eligible to meet the RPS only if and when four triggering events occurred:*
>
> ***1. A[lternative]C[ompliance]P[ayment]s.*** *An ACP is paid … in lieu of meeting the RPS. Under the Act, such payment will raise the presumption that there is an insufficient supply of Class I renewable energy sources to meet the state's RPS that year.*
>
> ***2. Material shortage of renewable energy.*** *Next, the DEEP Commissioner will need to confirm the presumption raised by the ACP by determining that the ACP resulted from a material shortage of Class I renewable energy sources and not from intentional or negligent action by the electric supplier or EDC that made the payment.*
>
> ***3. Insufficient Class I renewable energy sources in the state.*** *If the DEEP Commissioner confirms the presumption that there is an insufficient supply of Class I renewable energy sources to meet the state's RPS that year, the commissioner will then need to determine whether there were, or soon would be, adequate Class I renewable energy sources in the state to meet the RPS in succeeding years.*
>
> ***4. An RFP fails to fill the gap.*** *If the DEEP Commissioner determines that there is a present material shortage of renewable energy sources in the state and that there are inadequate resources to meet the RPS in succeeding years, the commissioner will then solicit proposals from providers of operational Class I renewable energy sources. The commissioner will be authorized to select the proposals necessary to ensure an adequate supply of Class I renewable energy sources to rectify any projected shortage and would then direct the EDCs to*

[7] Mary G. Powell, "Treatment Of Large Hydropower As A Renewable Resource," Energy Law Journal, Vol 32, 553; 2011. (From http://www.felj.org/docs/elj322/16-553-powell-treatment_of_large_hydro.pdf,), accessed Nov 15, 2013. Ms. Powell is Chief Executive Officer of Green Mountain Power of Vermont.

enter into power purchase agreements ("PPAs") based on the selected proposals for periods of up to 10 years.

If all four triggering events occur and the DEEP Commissioner is unable to obtain the proposals necessary to ensure an adequate supply of Class I renewable energy sources through an RFP, then the commissioner, beginning on January 1, 2016, may allow large-scale hydropower to meet limited portions of the RPS. Large-scale hydropower will be permitted to meet not more than one percentage point of the RPS by December 31, 2016. That limit will increase by an additional percentage point each year that the commissioner takes action to use large-scale hydropower to meet the RPS and is not allowed to exceed a total of five percentage points of the RPS by December 31, 2020. Large-scale hydropower selected through this process will be prohibited from trading in the New England REC market.[8]

In a way, the Connecticut legislation is the mirror image of Vermont's: whereas Vermont took unusual steps to accommodate hydroelectric energy imports, Connecticut took unusual steps to accommodate alternatives to it. Only if other class I renewables are not available can the Commissioner allow large-scale hydro to meet limited portions of Connecticut's RPS supply.

Connecticut's legislation is also interesting because it raises the prospect of a symbiosis between wind and hydro. If there's not enough wind, then hydro is welcome. This can be transformed into a more active proposition: maybe wind and hydro can be procured together?

Rhode Island

In Rhode Island, Renewable Energy Standard (RES) legislation passed in 2004, with subsequent amendments, requires that 16% of electricity sold in the state by 2019 be generated by a diverse portfolio of renewable technologies: solar, landfill gas, wind, biomass, small-scale (not large-scale) hydroelectric, geothermal, anaerobic digesters, tidal and wave, ocean thermal, biodiesel, and fuel cells using renewable fuels. According to the Rhode Island Public Utilities Commission:

In 2011, RES compliance was fulfilled … primarily by landfill gas (55.6%) and biomass (27.3%) facilities throughout New England and the adjacent control area of New York.

With market prices bumping up against the 2011 ACP rate of $62.13 per MWh, compliance costs incurred by the state's distribution company and competitive suppliers are at an all-time high. For example, Narragansett Electric's RES compliance costs rose to more than $8.4 million – four times that incurred to meet 2010 targets and a 53 percent increase above 2009 levels. These costs will ultimately be passed on to Ocean State ratepayers, either through regulated rates (i.e. Narragansett Electric) or through the prices offered to consumers by competitive suppliers. Moreover, RES compliance costs will continue to increase – at least in the short-term – as REC supply shortages persist and annual mandates increase.

[8] http://www.daypitney.com/news/docs/dp_4709.pdf

In its report for the 2011 compliance year (the most recent available), the Commission warns that:

> *It is important to note, however, that the continued availability of long-term contracts and access to renewable energy financing are important to sustaining regional RPS success. Based on recent policies established and revised within the Ocean State, including long-term contracting statutes and the Distributed Generation Standard Contracts law, Rhode Island remains a leader in this critical area of policy support. Elsewhere in New England, a shortage of long-term contracting appetite compared to the pipeline of renewable energy supply necessary to meet RES targets may affect New England's collective ability to meet established renewable energy standards in the mid- and long-term. Recent legislation to expand the long-term contracting obligation of Massachusetts utilities, as well as the November 2012 release of NESCOE's Coordinated Competitive Renewable Power Procurement Work Plan, suggests that the states understand the opportunity this market dynamic presents and are prepared to follow through with increased long-term contracting with renewable energy facilities.*

Some in the Rhode Island state government continued to express concerns about the RES supply picture. In late 2013, the Division of Public Utilities and Carriers reportedly recommended the Commission delay the 2015 increase in RES requirements out of concern about inadequate supplies of renewable energy credits.

Maine

In Maine, the *Renewable Resource Portfolio Requirement* has been on the books since 1997. Since then, the Public Utility Commission (PUC) adopted rules requiring each electricity provider to supply at least 30% of electric sales using electricity generated by eligible renewable and certain energy efficiency resources. The requirement had little practical effect because eligible facilities (those using fuel cells, tidal, solar, wind, geothermal, hydro, biomass or municipal solid waste, combined heat and power (CHP) facilities and other qualified "small power production facilities") were already producing more qualified renewable energy than was required. Subsequently, two separate classes of RPS eligible sources were designated. Class I includes renewables that have come on-line after September 1, 2005; class II includes the previously existing renewables were eligible to meet the 30% requirement set forth by the PUC. Municipal solid waste facilities and CHP facilities were deemed not eligible for Class I, and new wind installations were allowed to exceed 100 MW.

The schedule for the Class I standard started at 1% for the period ending December 31, 2008, and increases by 1 percent each year until it reaches 10% for the period ending December 31, 2017. It was this schedule that required the construction of new facilities. In the 2012 legislative session, a bill was introduced to remove the 100 MW capacity cap on qualifying RPS Class I resources, with the intention of allowing large hydro to satisfy the state's class I RPS. The bill was eventually abandoned due to lack of consensus. Similar measures were proposed in 2013 to allow large hydro as a Class I resource, as well as several initiatives from biomass plants seeking to qualify as Class I RPS resource.[9]

Maine is in the unique position of having the potential to satisfy much of New England's RPS requirements in the future. A 2012 NESCOE study of REC-eligible (hence, excluding large-scale hydro) energy that would be sufficient to meet New England's requirements indicated that "On-shore wind in Maine dominates the supply mix in 2016. It constitutes 72% of the most economical energy available in that year. In 2020, on-shore generation in Maine still constitutes 47% of the most economical energy, with increasing contributions by imports from New York."

Thus, Maine stands to benefit economically from development new onshore wind farms. A 2012 London Economics study concluded that *"as RPS policies across New England motivate new power plant construction, investment in Maine renewable generation has the potential to be a meaningful contributor to the state's gross state product ("GSP"). Assuming half of the proposed new wind projects in Maine are built in the future, 625 MW – at a total investment cost of $2,563/kW – this could result in approximately $560 million of investment in the state of Maine, which could lead to $1,140 million or a 2% increase over current GSP, and the creation of roughly 11,700 jobs during construction. These economic development benefits are cumulative for the $560 million of investment, but would in reality accrue over multiple years given the likely staggered timing of this investment."*[10]

New Hampshire

According to DSIRE, New Hampshire's RPS started in May 2007 and aims to require electricity providers to acquire RECs equivalent to about 25% of retail electricity sold by 2025. The RPS includes four distinct standards for different types of energy resources; these are classified as Class I, Class II, Class III and Class IV. Class I (15% by 2025) is new renewable energy provided by qualifying generators that began operation after January 1, 2006. Qualifying generators include wind, a range of biomass and landfill gases, ocean thermal, wave, current or tidal energy, methane gas, geothermal systems that begin producing thermal energy after January 1, 2013, solar-thermal systems that begin producing thermal energy after January 1, 2013, the biomass share of certain generators co-fired with fossil fuels, and others. Class II (0.3% by 2025) is a carve-out for new solar. Class III (8% by 2025) is existing biomass or methane systems up to 25MW. Class IV (1.5% by 2025) is existing small hydroelectric up to 5 MW. Finally, as in other states, electricity providers that do not meet the requirements will have to make payments (known elsewhere as Alternative Compliance Payments, or ACP) into a renewable energy fund.[11]

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[9] Information obtained from the DSIRE web site (http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=ME01R&re=0&ee=0) on November 16, 2013.

[10] "MPUC RPS Report 2011 - Review of RPS Requirements and Compliance in Maine," Prepared by London Economics International LLC for the Maine Public Utilities Commission, January 30, 2012, obtained from http://www.maine.gov/tools/whatsnew/attach.php?id=349454&an=1 on November 16, 2013.

[11] In 2013, the ACP payment for Class I is $55/MWh (except for class I thermal, which is $25/MWh), class II is $55/MWh, class III is $31.50/MWh, and Class IV is $26.50/MWh.

Interestingly, the hydroelectric energy Northeast Utilities – the owner of Public Service Company of New Hampshire -- has proposed to provide via the Northern Pass project does not qualify for RECs in New Hampshire.

Massachusetts

In April 2002, the Massachusetts Department of Energy Resources (DOER) adopted RPS regulations that required all retail electricity providers in the state to utilize new renewable-energy sources for at least 1% of their power supply in 2003, increasing to 4% by 2009. The RPS was significantly expanded by legislation enacted in July 2008 (Green Communities Act S.B. 2768). This legislation established two separate renewable standard. Eligible Class I resources include solar, wind, landfill gas, energy generated by certain new hydroelectric facilities, or certain incremental new energy from increased capacity or efficiency improvements at existing hydroelectric facilities. No provision was made for large-scale hydroelectricity. Massachusetts, like Connecticut, has re-evaluated the place of hydroelectric energy in its power mix. Legislation passed in 2013, however, reaffirmed the state's commitment to the RPS program, and provided additional flexibility for making substantial procurements via competitive requests for proposals.[12]

In May 2013, Governor Deval Patrick issued a statement indicating that "Massachusetts, Connecticut, Maine, Rhode Island and Vermont, have launched a regional initiative to expand large hydro imports into New England. The collaboration is part of the Patrick Administration's continued focus on expanding cleaner, cheaper power options for the Commonwealth." The states had previously set up the New England States Committee on Electricity (NESCOE) to evaluate, *inter alia, "*the opportunities, options and issues relating to the expansion of large hydro into New England…." And that "the partnering states recognize the benefits of clean hydro electricity, including reducing and stabilizing electricity prices, enhancing fuel diversity, increasing electric grid reliability, reducing environmental impact from the energy sector, and encouraging an energy future that utilizes resources from within the region and nearby borders…."

As of November 2013, this initiative had not yet given hydroelectric power the status it has in Vermont: REC eligibility. The Governors' May 2013 press release indicated that, "as large hydro is a well-established renewable resource that does not require incentives, it cannot be used to comply with the Massachusetts Renewable Energy Portfolio Standard (RPS)."[13]

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[13] Commonwealth of Massachusetts, Executive Office of Energy and Environmental Affairs, Press Release, "Patrick Administration Collaborates With Other New England States On Regional Initiative For Large Hydro," May 17, 2013.

Conclusion

When the RPS aspirations are taken together, the New England states will need about 17,000 GWh by 2020. According to a study commissioned by National Grid for its Rhode Island subsidiary, as of 2013, qualified supply was 7,316 GWh, leaving a projected gap in REC-eligible supply of about 10,000 GWh.[14]

Measuring this gap in terms of the number of MWs of wind that would have to be built by 2020, assuming a 35% capacity factor, New England states will have to contract to build approximately 3000MW of new wind generating capacity. Considering that only about 700MW have been built between 2000 and 2013, this is a tall order.

Thus, Connecticut's provision to allow large-scale hydro to fill part of this gap, under controlled conditions, is understandable. There's no reason, however, to see this as a wind *or* hydro issue. Connecticut has raised the prospect of a symbiosis between wind and hydro. If there's not enough wind, then hydro is welcome. This can be transformed into a more active proposition: could wind and hydro work together?

In the "all hydro imports all the time" construct, REC-eligible hydro undermines the native New England REC market. In the "all wind" construct, New England doesn't get the benefits of attractively priced, low carbon hydro and may not reach its RPS targets. Wind plus hydro seems to be a combination the region could get behind. Vermont obviously has a special interest in the growth of Quebec's supply in the region. Connecticut has loosened its RPS standards to allow large-scale hydro to play a greater part. Massachusetts welcomes hydro but will not count it towards its RPS compliance. The Governor of Maine has frequently expressed interest in hydro imports. Rhode Island signed a Memorandum of Understanding with NALCOR expressing interest in hydro from Newfoundland.

New Hampshire is a special case. Already a power exporter, it has a special interest in promoting power made from biofuels. For the Granite State, the proposal to build the Northern Pass to enable hydroelectric imports from Quebec has engendered a bitter permitting feud. The state government is trying to find a solution between the proponents of the project on the one hand, and seemingly implacable opposition to an overhead configuration of the Northern Pass on the other.

Assuming all the New England states, except New Hampshire, have interest in wind and hydro, the stage seems set to form a "coalition of the willing" and issue RFPs for projects that bring both wind and hydro into the region. The combination of Massachusetts, Connecticut, Maine, Rhode Island, and (perhaps) Vermont would constitute a formidable buying group.

Transmission as the Key to Getting What New England States Want

Assuming the New England Governors are persuaded that the "do nothing" alternative is (for most states) a path to RPS non-

[14] ESAI Power, LLC, "Assessment of Rhode Island's Resource Adequacy for Renewable Energy, September 25, 2013, A Study Prepared For National Grid and filed with the Rhode Island Public Service Commission.

compliance and over-dependence on natural gas, then which of the six proposed transmission projects should the states select in a competitive RFP?

"All Hydro From Canada All the Time"

Two of the proposed transmission projects provide an "all import" scenario from Canadian provinces. Specifically, the Northern Pass and the New England Clean Power Link (see maps nearby) provide HVDC conduits for electricity from Quebec into southern New Hampshire and southern Vermont respectively.

These are "supply push" projects based on the (presumed) desire of Hydro-Québec to export its abundant supply of hydroelectric energy. As of November 2013, HQ has publicly aligned itself with Northern Pass, but not with the New England Clean Power Link. The Northern Pass website states that the project *"will import up to 1,200 megawatts of clean energy from our Canadian energy supply partner, Hydro-Québec. Access to this low-cost energy resource will help diversify our region's power supply and keep pace with our rising demand for energy. By displacing electricity generation from fossil fuel power plants, this renewable power will reduce carbon dioxide emissions by up to five million tons a year, equivalent to the annual emissions of nearly 900,000 cars."*[15]

As shown in the map, the Northern Pass project was initially conceived as a 187-mile overhead transmission line. In the face of considerable opposition (including the Society for the Preservation of New Hampshire Forests, the Appalachian Mountain Club, and the Conservation Law Foundation) , the sponsors agreed in the summer of 2013 to bury eight miles of the project in the particularly sensitive northern areas of the state. Time will tell whether this concession is sufficient to enable the project to get its state permits.

Perhaps in response to the distress of the Northern Pass project, an alternative Quebec connection was proposed in the fall of 2013 called the New England Clean Power Link. As shown in the map nearby, this project would enter New England at Lake Champlain on the Vermont-Quebec border, stay submerged in the Lake for some [120] miles, and then be buried in a terrestrial right of way to a connection point in Ludlow, Vermont.[16]

The primary distinction between the Northern Pass and the Clean Power Link? The Northern Pass is predominantly an overhead transmission line; the Clean Power Link is entirely buried. As "supply push" projects, they presumably do not need to be directly financed by the consumers. Northern Pass has indicated that it is a "participant funded" project, which in this instance means that HQ will pay a tariff to the developers that will enable them to finance the project.

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[15] From http://www.northernpass.us/energy-environment.htm, accessed November 15, 2013.
[16] From http://www.necplink.com/about.php; accessed November 15, 2013.

The fact that the Northern Pass is a supplier-sponsored project has important implications. It means the owner of the transmission rights (HQ) will have an opportunity to sell its energy at the southern terminus of the Project (either southern NH or southern Vermont) at the prevailing price in that market. It stands to reason that HQ will seek to recover the cost of transmission service it pays to the Northern Pass (or the Clean Power Link). In the only other comparable recent sale of energy via contract by HQ to New England utilities, the energy price was set at $58 per MWh, and the details on future price escalation were not released. That price reflects the cost of energy in a situation where the transmission system was already fully in place. The old Grid had already been built out to accommodate this flow from Quebec.

Future additional energy flows from Quebec (or Newfoundland) will require new transmission be built. Whether it's the Northern Pass or the Clean Power Link, the cost of transmission to get hydroelectric energy from their source in northern Quebec to the market in southern New England is, in the opinion of the author, likely to be about $1500 to $2000 per kw. Developers on the U.S. side of the line depict a cost of $1,000 to $1,200 per kw for the US portion. Assuming Hydro Quebec has not yet built its grid to accommodate this new energy flow, we would expect a similar order of magnitude of cost on the Canadian side of the border.

Assuming the all-in cost is $2,000 per kilowatt, and the project is financed over forty years (which is an appropriate tenor for such an infrastructure project), the levelized cost of transmission will be approximately $25/MWh.[17] Thus, if the hydro energy is $60/MWh, and the transmission cost is $25/MWh, the all-in cost is $85/MWh. If the hydro energy is closer to its average cost (EIA's estimate is $90/MWh), the all-in cost would be $115/MWh.

All Wind

The polar opposite of "All hydro from Canada all the time" is "All offshore wind all the time." Three of New England's six states – Massachusetts, Maine and Rhode Island – have excellent offshore wind regimes. It is widely agreed that thousands of MWs of wind farms could be built offshore. In Massachusetts and Rhode Island, wind machines could be installed in relatively shallow water. In Maine, the installation would be in deep water.

There is, of course, an immense amount of offshore wind development activity taking place in Europe, and the prospects for offshore wind are also very bright in Asia. The vast majority of such development, however, is taking place in countries where the cheaper on-shore wind has already been harvested, and where the underlying price of electricity is quite high, compared to the United States. For the most part, Europe does not have the abundance of natural gas at the low prices that prevail in North America. Thus, for European countries, paying $150-$200/MWh for offshore wind is not nearly as much "out of market" as it is here.

Because there are no operating offshore wind farms in North America yet, the cost of offshore wind is still a matter of conjecture. The U.S. Energy Information Administration's *Annual Energy Outlook 2013*

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[17] This is an approximation. The actual number will of course depend on final construction, financing, and maintenance costs. We suggest this estimate has a ± 20% error range.

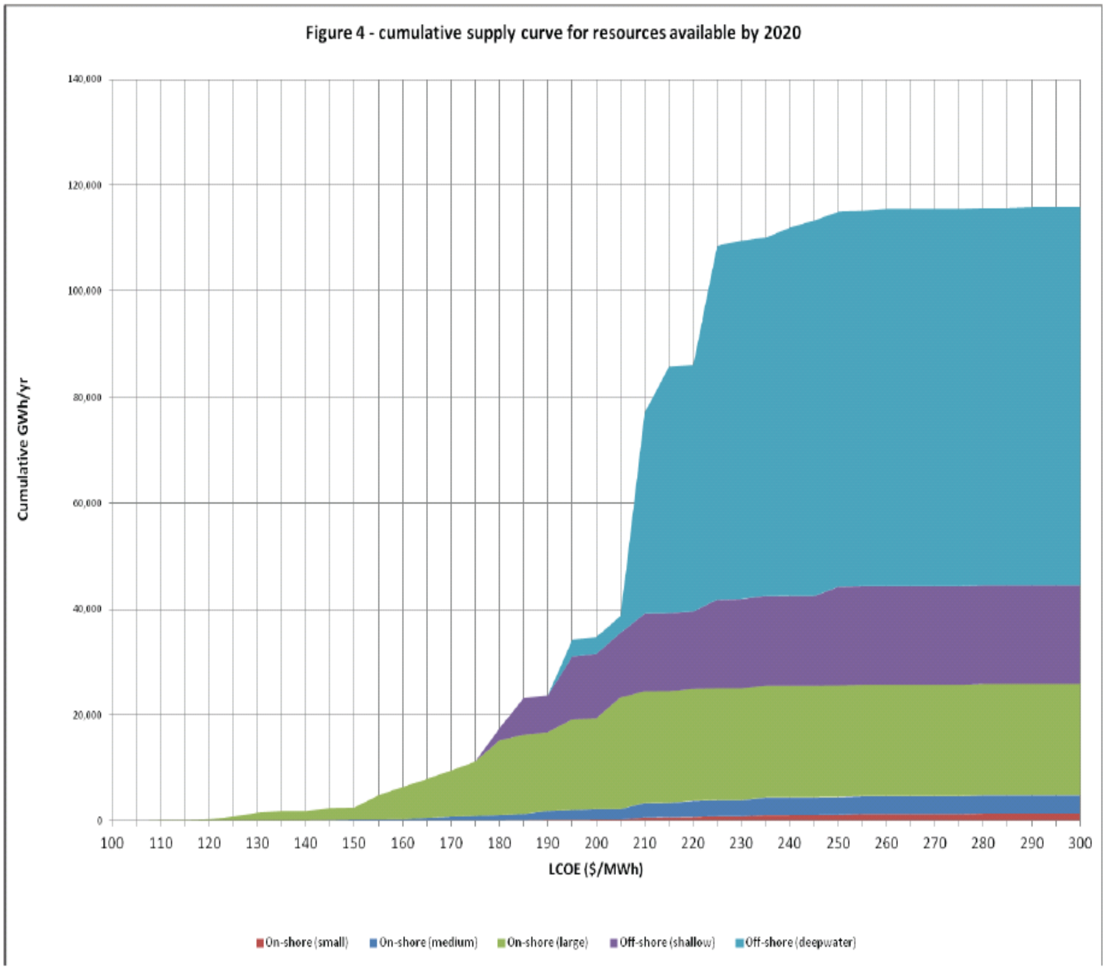
estimated the all-in, levelized cost of offshore wind in a US setting will be $221.50/MWh. The Cape Wind project secured a contract from National Grid (and later NStar) to sell half of its supply for a price that starts at $187/MWh, and increases by 3.5 percent per year.

Offshore wind is obviously more expensive than imported hydro or onshore wind. In defense of offshore wind, Cape Wind has argued that "*Cape Wind will help to stabilize and even reduce the price of electricity. Cape Wind will do this in 3 ways:*

> *1) Cape Wind will reduce the clearing price for electricity in the New England spot market by reducing operations of the region's most expensive power plants, providing more than $4 Billion dollars in savings to the New England wholesale electric market over the 25-year operating life of the project, according to a 2010 study by Charles River Associates.*
> *2) Cape Wind will reduce the implementation costs of the Renewable Portfolio Standard to Massachusetts electricity consumers by increasing the supply of renewable energy certificates.*
> *3) Cape Wind is selling its power in Long Term Power Purchase Agreements of 15 years in length, providing electricity consumers with far greater electric price stability and price certainty than is typically available."*[18]

Behind Cape Wind is the potential for thousands of additional off-shore megawatts, but at a substantially higher price than either on-shore win or hydro. NESCOE evaluated where offshore wind would fit into the "supply curve" for New England renewables. The chart below summarizes its findings:

[18] From http://www.capewind.org/FAQ-Category9-Cape+Wind+and+Economics-Parent0-myfaq-yes.htm#49; accessed November 19, 2013.



1. Small and medium onshore wind barely registers on the volume side of the chart. Whatever can be built economically should be built, but it doesn't make a dent in the total quantity of renewable MWhs needed.
2. Large onshore wind projects are clearly the "next" increment of supply that should be harvested, taking least-cost criteria into account. NESCOE properly assigns a range of costs from $100 to $150/MWh on this part of the supply stack. Some 20,000GWh (or some 6,000MW above and beyond what has already been developed) are theoretically available in New England in this price range.
3. Offshore wind's potential is divided into shallow and deepwater. The shallow water installations have the potential for another 20,000GWh of clean energy, but at a price of more than $175/MWh. Deepwater wind potential is virtually limitless, at these higher prices.[19]

[19] NESCOE, "Renewable Resource Supply Curve Report," January 2012.

NESCOE's description of the offshore is a reasonable approximation of the abundant amount of clean energy New England can access, at these prices. The strategy NESCOE's supply curve implies, however, is "harvest the onshore energy first." In this context, Cape Wind can provide a valuable lesson in offshore development. But the bulk of the next 2,000 to 3,000MW should come from onshore installations, if transmission paths can be found that are acceptable to the public.

The Wind-Hydro Portfolio

Three projects have been proposed that provide the potential for wind and hydro to work together: the Green Line 1200, the Northeast Energy Link, and the Grand Isle Intertie.

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The Green Line 1200 is a 1200MW hybrid land-and-sea high voltage direct current (HVDC) project that will connect up to 1200MW of new wind energy developed in Northern Maine, "firmed up" by imports of power from the provinces of New Brunswick, Quebec, or Newfoundland (via) Nova Scotia, buried under the ocean floor from Searsport, Maine to a landfall near Lynn, MA, from which a buried cable would inject the power into the large 345kV Wakefield, MA substation, in the heart of the Northeast Massachusetts ("NEMA") market and into the "Mass Hub." New England Independent Transmission Co. LLC is the sponsor.

As shown in the map below, this project combines a number of attributes. First, it is both a path for up to 1200MW of wind to be developed in Maine to reach the southern New England market, and a path for Canadian energy (hydro, wind, or other) to reach the same market when the wind isn't blowing. The sponsors envision giving wind energy preferential (a.k.a., "firm") access, and other sources "firming" (or secondary or interruptible) access. Because the area of Maine where the wind farms would be developed is not already incorporated into the New England market, and is in fact closer to the New Brunswick market both geographically and electrically, the Green Line would include a new, 345kV AC connection to the New Brunswick Grid. Thus, when the wind blows, 1200MW of northern Maine wind generation would have direct access to the Green Line; when it doesn't blow, any source that can be conveyed via the New Brunswick bulk power Grid would have access to the Green Line. The map shows that the Green Line provides a path for hydroelectric energy from New Brunswick, and Hydro Quebec, and Newfoundland (via a new project to be developed with Nova Scotia) to the southern New England market. Green Line 1200 has secured an easement for the transmission of electric power down an existing and lightly used railroad line from Houlton, Maine to Searsport, Maine. At Searsport, the project would use a subsea route to a landfall in Lynn, NH. From Lynn, a buried cable would be connected to the National Grid substation in Wakefield, Massachusetts.

A second attribute of the Green Line is that, as an HVDC connection, it could be used to convey generating capacity that would qualify for capacity credit in the New England Forward Capacity Market (FCM). The conditions under which this could be done are quite rigorous (essentially, generation in New Brunswick would have to be de-listed as capacity there, in order for that capacity not to be double-

counted), but if such a capacity resource would have value in the Northeast Massachusetts market (NEMA), the Green Line could be part of a program to provide a substantial amount of it.[20] The "all import" transmission projects (Northern Pass and Clean Power Link) are not being configured to provide such capacity services.

Green Line 1200 potentially provides a combination of wind (satisfying the REC obligations of all the states), and hydro (satisfying the more complex opportunities for hydro to provide REC-eligible energy in Connecticut). An RFP from New England states could stipulate that the "firming energy" desired from Canadian suppliers via the Green Line would have to have certain attributes (for example, hydro power could be given a preference, so could Canadian wind energy). Thus, the Green Line has been designed to provide both a substantial opportunity for both Maine-based wind power <u>and</u> Canadian hydro to reach the market.

In 2013, wind developed in Northern Maine won 2013 RFPs from both Massachusetts and Connecticut utilities. The details on the prices charged by the Maine generators have not been released, but press reports indicate prices "will hover in the 8 cents per kilowatt hour range over 15 to 20 years." [21] Thus, Maine wind is about $100/MWh lower than wind from offshore projects. Some of that $100 needs to be used to pay for transmission.

Like the "all-import" projects, the Green Line is likely to cost between $1,500 and $2,000 per kilowatt to build. Thus, spread across all the MWhs the Green Line can convey (not just wind, but hydroelectric energy too), the tariff for the line will be in the neighborhood of $25/MWh. A comparison with the "all import" transmission projects requires two adjustments. First, (and keeping it simple), assume the wind energy costs $80/MWh, and takes one-third of the capacity. Assuming the remainder of the Green Line capacity is supplied with hydro energy at $60/MWh, then the all-in cost of energy across the Green Line is ($80*1/3) + ($60*2/3) or $66/MWh, plus $25/MWh for transmission for a total delivered cost of $91/MWh. If the cost of the hydro is $90/MWh, the all-in cost of Green Line's energy would be $111/MWh. Second, the Green Line must be given some credit for allowing ratepayers to avoid Alternative Compliance Payments. Assuming those average $60/MWh (each state has its own specific

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[20] The intricacies of the New England FCM are beyond the scope of this paper. Suffice it to say there's a reasonable likelihood that the NEMA market will command a premium in the FCM, and generation via the Green Line would be a competitive entrant in the periodic auctions that determine the payments to capacity resources.
[21] "Exporting Maine's Wind Energy," Portland Press Herald, October 6, 2013.

schedule), and assuming only 33% of Green Line's energy is REC-eligible (i.e., wind), there should be a $20/MWh credit for the Green Line. Thus, one could argue the all-in cost of clean energy for Green Line is between $71 and $91/MWh (compared with a range of $85 - $115 for the all-import transmission projects).

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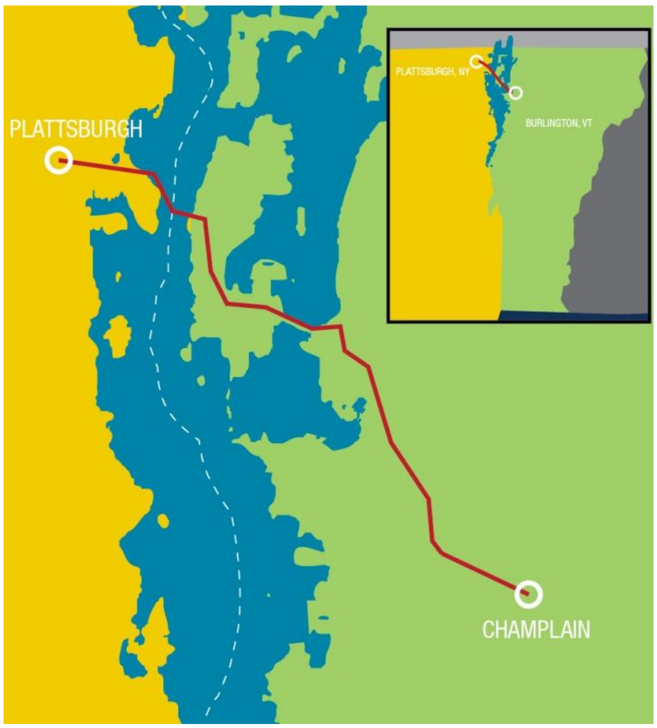
The Grand Isle Intertie (GII) is a 400MW high voltage alternating current (HVAC) project that will enable up to 400MW of wind from New York, "firmed up" by imports of power from New York, to reach New England. The approximately 30-mile project will be buried under Lake Champlain between Plattsburg, New York and Burlington, Vermont. It will be installed in its entirety along either existing utility ROWs or public roads. Anbaric Transmission is the sponsor.



As clean transmission projects go, GII is relatively small, which is appropriate given the markets it serves. Its function is to more tightly integrate the northern part of New York state – which has been a beehive of wind development activity over the last ten years – with Vermont and New England. Upstate New York has wind and hydro resources (both within the state, and access to Quebec via long-established high voltage AC connections.

GII is likely to cost approximately $1,000 per kilowatt to build, compared with $1,500-$2,000 for the "all-import" or the Green Line project. Thus, spread across all the MWhs GII can convey, the tariff for the line will be in the neighborhood of $12/MWh. Upstate New York wind costs approximately $70/MWh. Assuming the remainder of the GII capacity is supplied with hydro energy at $60/MWh, then the all-in cost of energy across the GII is ($70*1/3) + ($60*2/3) or $63/MWh, plus $12/MWh for transmission for a total delivered cost of $75/MWh. If the cost of the hydro is $90/MWh, the all-in cost of GII's energy would be $95/MWh.

As with the Green Line, for states that have RPS requirements and Alternative Compliance Payments, (this excludes Vermont), GII must be given some credit for allowing ratepayers to avoid those payments. Assuming those average $60/MWh (each state has its own specific schedule), and assuming only 33% of GII's energy is REC-eligible (i.e., wind), there should be a $20/MWh credit for GII. Thus, one could argue the all-in cost of clean energy for GII is between $55 and $75/MWh (compared with a range of $85 - $115 for the all-import transmission projects). This makes GII the most economical of the proposed transmission projects.

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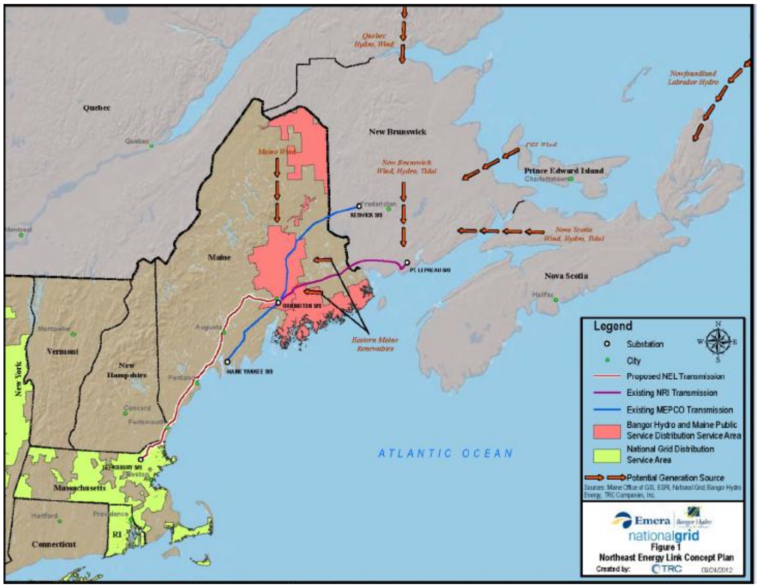
The Northeast Energy Link is a 1200MW HVDC project from the Orrington (near Bangor), Maine area to Tewksbury, Massachusetts. The NEL proposes to bury the transmission cable alongside Interstate 95 (a.k.a., the Maine Turnpike), a route of approximately 230 miles. National Grid and Emera (whose affiliates include Nova Scotia Power, Bangor Hydro, and Maine Public Service Company) are the sponsors. NEL presents an alternative to the Green Line's path in the form of an HVDC cable located within an Interstate Highway Statutory Corridor.



The NEL's northern terminus is near Orrington, Maine, thus it does not extend as far north (by some 180 miles) as the Green Line. If Maine were to be the location of the next 1200MW of wind, much of that wind would likely be in the far north (closer to the Green Line terminus), and thus, if NEL were selected, the wind developers would have to build transmission down to Orrington to connect. At that terminus, NEL connects with two existing transmission lines from New Brunswick.

NEL breaks new ground in the transmission development community by proposing to install the HVDC cable along an existing interstate highway. To the best of our knowledge, such an installation has not yet been attempted in North America. Aware of this and other transmission plans, the Maine legislature passed "An Act Regarding Energy Infrastructure Development" in July 12, 2010, establishing eight criteria determining whether such a corridor could be used for electric transmission purposes.

1. Do no harm to opportunities for energy generation within the State, and preferably materially enhances those opportunities.
2. Likely to reduce electric rates or other relevant energy prices or costs for residents and businesses within the State of Maine.
3. Minimize conflict with the public purposes for which the state-owned land or asset is owned.
4. Increase long-term economic benefits for the State
5. Ensure efficient use of the statutory corridor through collocation of energy infrastructure
6. Limit effects of energy infrastructure on the landscape
7. Increases energy reliability, security and independence of the State
8. Reduce the release of greenhouse gases

The application of the Maine corridor bill is an example of how major transmission projects that propose to use public lands inevitably intersect with other state public policy issues. One expects transmission projects to affect state environmental efforts – that's why state permitting mostly concerns environmental assessments. In Maine's case, the NEL also intersects with state economic policies (criteria 1 and 4), energy policies (criteria 2 and 7), land use policies (criteria 3 and 5), as well as environmental policies (criteria 6 and 8). It remains to be seen how Maine's review of the NEL navigates this array of criteria.

NEL's proposal to bury the HVDC cable along the I-95 corridor also raises important issues in the debate among and within all New England states about the costs and benefits of burying transmission projects. In the debate over the Northern Pass in New Hampshire, proponents of buried cables now cite cost comparisons between the Northern Pass and the proposed Clean Power Link in Vermont. For example, the Conservation Law Foundation notes:

> *Northern Pass's $1.4 billion overall cost is $7.5 million per mile. This number is not directly comparable with the specific cost estimates for underground technology—a real comparison is not possible because Northern Pass's developer has not released more detailed cost estimates of the kind provided for the Champlain Hudson project or reflected in the white paper, which show specific material and installation costs. But Northern Pass's overall cost per mile* is *quite comparable with the overall cost per mile of the recently announced New England Clean Power Link, which is $8 million per mile.*[22]

The 227 mile NEL is estimated to cost about $2 billion, or about $8.8 million per mile, which is similar to cost estimates published for the other major projects.[23]

Competitive Issues

In deciding which of these transmission projects to support, regulators will naturally face two key questions:

1. Is the project buildable? Can it get the state and public acceptance necessary to get the environmental and land use permits?
2. How much do these projects cost?

There is understandable confusion about the per-mile cost of these contending projects. At first glance, it appears that the largely above ground Northern Pass costs about the same on a $/kw basis as the largely underground Green Line, NEL or Clean Power Link. The reality is that these provisional estimates are just that – estimates. The cost of installation of major transmission projects is entirely dependent on terrain. For NEL, the challenge is to construct an installation system next to a major super-highway. To the best of our knowledge, this has never been done in North America, at least not to the 227 mile extend contemplated by the NEL. For the Northern Pass, if it is forced to bury its cable the entire length of its route, the challenge is literally the granite in the Granite state: its burial may be more a matter of

[22] From http://www.clf.org/blog/tag/northern-pass/.
[23] From http://www.northeastenergylink.com/files/documents/nel_presentation.pdf. These cost estimates typically include the cost of converter stations, substations, overall project development, and financing. Thus, the pure undergrounding cost is only part of these per-mile estimates.

blasting a path through mountainous rocks than digging a ditch through dirt. For Green Line, the challenge is installing a cable along a railroad right-of-way (in its terrestrial portion), and on the ocean floor (in its marine portion). For the Clean Power Link and Grand Isle Intertie, the challenge is installing a cable under the bottom of the rather complex ecosystem of Lake Champlain. Waterways have been used[24], but only after extensive review from the agencies who look after the rivers, lakes, and oceans proposed as conduits.

While the interest in the true costs of these competing projects is understandable, an equally urgent task is to create a procurement method that prevents what Wall Street analysts recently described as routine:

> *Given the potential for projects to be pitched 'below' cost through the solicitation process, we believe PJM may under-emphasize this criteria [sic] in identifying the best solutions to its projects. Meanwhile, we believe MISO may prove a more 'competitive' framework, with more explicit parameters around projects it is seeking. (email from UBS, 11/18/2013)*

The best approach to getting "real" cost data is to conduct a competitive procurement for the projects, requiring both a fixed price and stipulated in-service date. That approach has been used in New York and has been successful in the development of the Neptune and Hudson transmission projects. A somewhat less onerous method was used in Texas that also had good results[25].

The second issue is even more difficult: is the project buildable? Regulators deciding between competing projects – each at an early stage of development – will have to draw their own conclusions about the degree of difficulty the projects will face in the permitting and public approval processes. The level of opposition to the Northern Pass project appears to be largely the result of its above-ground design. Experience has shown that buried projects encounter less public opposition than overhead projects, but burial along I95 (the NEL) or in Lake Champlain (Grand Isle and Clean Power Link) also present challenges that will take several years to overcome. While utilities are accustomed to having and using eminent domain for reliability transmission projects, New Hampshire has shown that any effort to use it for "economic" projects will face stiff opposition.[26]

Strategic Issues: The Long-Term Implications of the Choice of Transmission Projects

As noted earlier, when the RPS aspirations of the New England states are taken together, they will need about 17,000GWh by 2020. Since qualified supply as of 2013 is 7,000 GWh, there is a projected gap in REC-eligible supply of 10,000GWh. How big is that in terms of the new transmission projects that need to be built?

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[24] The Neptune and Hudson HVDC transmission systems between New Jersey and New York used buried cables under the Atlantic Ocean and Hudson Rivers respectively. See www.NeptuneRTS.com and www.HudsonProject.com.

[25] TO BE COMPLETED

[26] The New Hampshire legislature passed HB 648, "An Act relative to eminent domain by public utilities," on March 9, 2012.

Some of the 10,000GWh gap will be filled by new solar installations. In 2013, solar installations (mostly in Massachusetts) provided 465GWh to the grid. Estimates of how much can be built in New England vary, but an incremental 2000GWh of new solar is not out of the question. Although additional biomass and other somewhat niche sources cannot be ruled out, the remaining clean energy gap of 8,000GWh will have to be filled primarily with wind, or, in the case of Connecticut, with imported hydro.

Using onshore wind as a gauge, assuming capacity factors increase to 35%, New England states will have to contract to build about 2600MW of new wind farms between now and 2020, or import 1000MW of hydro from Quebec, New Brunswick, or Nova Scotia/Newfoundland. The hydro scenario is complicated by the fact that some but not all New England states are willing to let hydro provide all of these MWs to satisfy their RPS obligations.

Given this fact pattern, wouldn't projects that provide access to both wind and hydro be desirable?

In thinking this over, several factors have to be taken into account in selecting the next transmission projects. First, it is extraordinarily difficult to develop new transmission lines in New England. Under the panoply of environmental and market rules that pertain to electricity, the projects take up to ten years to develop from start to finish. Each of the projects described in the pages above, except the Clean Power Link, has been under development for more than five years. If one or more projects is selected in 2014, it will be in service in 2018-2019.

Second, the projects require significant amounts of capital. The per-kilowatt cost is, at a minimum, $1,000, and most of the projects will be closer to $2,000. These costs are an unavoidable part of securing the next 3000MW of clean energy. Advocates of clean energy cannot have it both ways: they cannot simultaneously want 3000MW of renewable energy, and not pay for the transmission. There is no combination of solar, microgrids, or distributed energy (most of which, incidentally, requires natural gas) that can achieve 3000MW.

That said, the choice of transmission projects will influence the New England area for generations to come. To put it bluntly, the "all imports" projects effectively outsource the task of developing clean energy to our Canadian neighbors; the "all [offshore] wind" projects would lock New England into an extraordinarily expensive energy source for the next twenty years, when less expensive resources are only a transmission line away. It stands to reason that a compromise between "all imports" and "all wind" is the right selection at this time.

Using that filter, how do the projects stack up?

The Grand Isle Intertie provides New England with access to economical upstate New York wind, potentially firmed up by hydro from either New York or Canadian provinces. Since the per-kw cost of the Grand Isle project is the lowest of all the projects reviewed here, and New York wind is as affordable as Maine wind (and offshore wind), this is probably the most economical project. It will be buried its entire route, and thus is unlikely to encounter the stiff public opposition that has confronted Northern Pass. It is also under active development, could go into construction in 2015, and be in service in 2017.

The Green Line and the Northeast Energy Link provide New England with access to economical upstate Maine wind, firmed up by hydro (or other low-carbon energy resources as determined by an RFP) from other upstate Maine resources and Canadian provinces. Both would provide a massive stimulus for New England wind, and (in the long run) give New England a choice between Quebec, Newfoundland, and New Brunswick clean energy sources (that competition might serve New England ratepayers well in the long run), and provides 1200MW of clean energy for the greater Boston area. Those who issue the RFP will have an opportunity to see the detailed development plans and costs of these two projects, and can decide which one should be selected. Grand Isle would stimulate the wind industry and hydro imports via New York at the most affordable prices because it creates a short and relatively inexpensive connection between the New York and New England grids. The wind+hydro capability of all three of these projects will be compatible with the expressed preferences of Massachusetts, Rhode Island, and Connecticut.

The Northern Pass and Clean Power Link connect New England to additional hydroelectric energy and perhaps also some wind energy generated in Quebec. Their project design does not allow them to "pick up" wind generated in New England: they enable "all imports all the time." The entry point would either be southern New Hampshire or southern Vermont. Vermont would welcome additional imports of hydroelectricity, and if other states make hydro REC-eligible, Vermont electric consumers would gain an additional benefit. Connecticut has put a program in place in which, failing enough wind supply, hydro could qualify for RECs there. To get the maximum benefit from these projects, Massachusetts and Rhode Island would also have to amend their RPS rules to enable hydro to qualify for RECs.

The selection of one of these projects will have economic, environmental, and energy consequences for decades, indeed for generations of New England electric ratepayers.

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Whichever project is chosen, the need to build out the Grid for clean energy is clear. Remember that for virtually all "dirty," fossil-fuel based power plants, connecting to the Grid was, for all practical purposes, free. We, the ratepayers, collectively paid for the massive electrical system that connects us all to the power plants that keep our lights on, power our factories, maintain a comfortable climate in homes, schools and offices, and keep our hundreds of millions of computers, smart phones, and tablets charged.

We take electricity for granted, until something happens to put it, momentarily, on the front pages of our attention spans. A blackout, a nuclear accident, an unwelcome power line intrusion, or a gas pipeline explosion is the usual source of news in the power business. It's really hard for the power business to get on the front pages any other way. That's a shame because once every ten years or so massive changes occur that ought to be front page news. New England is on the cusp of one of those changes: a necessary expansion of the Grid to accommodate large-scale renewables and a cleaner energy future.