Escalating New England Transmission Costs and the Need for Policy Reforms

June 2011

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Acknowledgements

ENE would like to thank the individuals who reviewed drafts of this paper and provided valuable insights and feedback: Chair Ann Berwick and John Keane, Massachusetts Department of Public Utilities; Eric Bryant, Maine Office of Public Advocate; Heather Hunt, New England States Committee on Energy (NESCOE); Paul Peterson and Doug Hurley, Synapse Energy Economics; Larry DeWitt, The Commons and Pace Energy Project; and Andrew Landry, Preti Flaherty Beliveau & Pachios LLP.

We would also like to extend our appreciation to the Orchard Foundation for supporting ENE's work on transmission and sustainable energy research.

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About Us

ENE (Environment Northeast) is a non-profit organization that researches and advocates innovative policies that tackle our environmental challenges while promoting sustainable economies. ENE is at the forefront of efforts to combat global warming with solutions that promote clean energy, clean air and healthy forests.

Mission

ENE's mission is to address large-scale environmental challenges that threaten regional ecosystems, human health, or the management of significant natural resources. We use policy analysis, collaborative problem solving, and advocacy to advance the environmental and economic sustainability of the northeastern United States and Eastern Canada.

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Executive Summary

Electric utility transmission system expenditures in New England have skyrocketed in the last ten years, with expenditures in real dollars up by 5 to 6 times their year 2000 level. Year 2008 expenditures were a full 17 times higher than in 2000. Planned expenditures are projected to remain very high in coming years and New England transmission expenditures are growing at a dramatically faster rate than those of the rest of the country (Figure 2). New England utilities have planned for an additional $4.75 billion in investments (Figure 3).

Transmission spending in New England is leading to significant increases in the transmission component of electricity rates, as seen in average rate information available for Northeast Utilities (Figure 5, NU companies used as an example). While historical rate component information is not readily available in most states, and current transmission rates vary somewhat by utility in New England, in 2011 most utilities appear to be charging transmission rates similar to those in Connecticut (Figure 6). On the other hand, expenditures on the distribution system have stayed basically the same.

Grid reliability is critical to the region's economic, energy and environmental future. However, in New England, the current selection, planning and financing options favor large scale, expensive transmission line expansions. The costs of transmission projects determined necessary for grid reliability are socialized – meaning that ratepayers in all six states in the New England power grid pay in proportionate shares. Lower cost, cleaner alternatives to large scale transmission projects often exist. These "non-transmission alternatives," or NTAs, include options such as energy efficiency, demand response, smart grid technologies and small scale, clean distributed generation. Adopted alone or in combination, they can replace or defer the need to construct new transmission lines. In cases where the goal is to address local reliability, they can eliminate or defer the need to construct new transmission lines –for a lower net cost than traditional poles and wires. However, under current rules, NTA costs cannot be socialized among regional ratepayers. Instead NTA costs are paid by the ratepayers of an individual utility or state. This policy puts NTAs on an un-level playing field and at a significant disadvantage. Furthermore, utilities earn a higher rate of return on new transmission investments than they do on other capital projects or providing other services such as energy efficiency programs. The transmission investment decisions being made now and in coming years will affect billions of dollars in new investments – costs that will be passed on to consumers. The current system used to determine new investments must change in order to secure a clean, low-carbon and competitive economic future for New England.

The transmission planning and investment policies that exist today in New England were developed in a different age, when large power plants were constructed near the region's population centers. Electric transmission system planning and financing has not kept pace with changes in energy technologies and environmental and consumer goals. The impact of decisions by states to dramatically increase investments in demand side resources – including energy efficiency, demand response, distributed generation, and on-site combined heat and power systems – need to be considered before spending hundreds of millions or even billions of dollars on new or upgraded lines. Energy efficiency and new technologies that help consumers control energy use, such as computer controlled systems, and technologies that allow power generation on the site of a customer's home or business are demand side resources, which do not rely on power being transmitted. These resources will have a direct and significant impact on how our transmission grid is sized and on whether lines should be built or expanded. NTAs also address concerns about the land use impacts of new transmission lines; with investment in efficiency and consumer sites, new lines can be avoided.

In addition to capturing the tremendous benefits of energy efficiency, developing renewable energy is another regional goal that requires a new way of thinking about the shape and location of the grid. For example, renewable resources like wind power are often located far from population centers. The challenge is to construct a system that facilitates development of new clean power sources and energy efficiency – whether these resources are located at a wind farm or inside the steam pipes of a paper company.

Transmission policy should coordinate with the advances states are making in furthering efficiency and demand side energy solutions. It should incorporate efforts to help consumers use energy more efficiently, embrace the exciting potential offered by new energy technologies and the need to increase our reliance on clean, renewable power and other distributed resources. The grid of the past – and the outdated process used to determine new investments – must change if we are to have a system that can take the northeast into a competitive economic future and a clean, low carbon energy era.

This paper outlines the current electric transmission system reliability policies in New England, highlights selected case studies that identify barriers and opportunities, and recommends some ways for policy makers to reform system planning and project selection. The goal is to establish a more comprehensive and inclusive process that would deliver a reliable system at lower cost.

New electric system reliability policy should include:

- Full assessment of the potential for demand-side resources and investments in energy efficiency, demand response, and distributed generation in the review of reliability and the need for new resources to address constraints;

- Better description and quantification of the transmission reliability need and full consideration of non-transmission alternatives, including a level evaluation process, to address a portion or all of the reliability need;

- Consistent treatment of non-transmission alternatives and transmission investments in terms of payment;

- Reform of utility incentives to provide incentives for investments in lower cost non-transmission alternatives that are at least as attractive as current incentives to build large, capital-intensive transmission projects while bringing current transmission incentives down; and

- Increased authority for state regulators in developing changes to rules and completing electric system planning, a reduced role for ISO New England and industry stakeholders, and, ideally, an increased focus by FERC on achieving the goals identified here and also in keeping the region's electricity rates reasonable.

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1.0 Introduction

Updating the electric transmission system is critical to the region's economic, energy and environmental future. Decisions being made now and in the coming years will affect billions of dollars in new investments, paid for by consumers. In order to make good decisions, the process needs to incorporate the increased efforts to help consumers use energy more efficiently, the exciting potential offered by new energy technologies and the need to expand our reliance on clean, renewable power and other distributed resources. The grid of the past – and the outdated process used to determine new investments – must change if we are to have a system that can take the northeast into a competitive economic future and a clean, low carbon energy era.

New approaches to energy use and planning are changing the size and shape of transmission infrastructure going forward. We are developing renewable energy resources, like wind power, that might be located far from population centers. At the same time, increasing investments in energy efficiency and new technologies that help consumers control energy use, such as computer controlled systems, and technologies that allow power generation on the site of a customer's home or business, may have a huge impact on how the system should be sized. The challenge the electric grid faces is to construct a system that facilitates new clean power sources and energy efficiency – whether at a wind farm or inside the steam pipes of a paper company. The focus of this paper is on electric system reliability and the need to transform how planning is completed and non-transmission alternatives (NTAs) are considered and paid for.

Historically, decisions about whether to build or extend transmission lines were made at the state level with little focus on comprehensive regional decision-making. That changed with the advent of Independent System Operators like ISO New England (ISO-NE). Power sources are located throughout the region, exporting electricity along lines that are hundreds of miles long. Decisions about spending hundreds of millions of dollars on new or upgraded lines are closely related to other important energy resources choices. For example, many states across the country and particularly in New England are dramatically increasing investments in energy efficiency and promoting other demand side energy resources like distributed generation and on-site combined heat and power systems. These growing parts of our energy system do not rely on power being transmitted but rather on using energy more efficiently and generating more power on site. They have a direct and significant impact on how our transmission grid is sized and whether lines need to be built or expanded.

The current transmission planning process is reactive. It is almost always driven by events external to the regional system operator, including requests to connect new generators or customers or comply with legal, regulatory, safety, or reliability requirements. This process limits our ability to choose cleaner, lower cost options for meeting electricity needs. Reactive transmission planning often identifies transmission needs on a schedule that is too late for the incorporation of cost-effective solutions such as energy efficiency, demand-side resources, or strategic placement of distributed generators. In addition, the rules on payment for transmission services lock out NTAs like efficiency or distributed generation, because traditional transmission costs are divided amongst all states in the region while the costs of NTAs must be paid by individual states. If our region is to have a modern transmission system, then a longer term, system-wide planning process is needed. The new process should reflect all regional energy goals including reliability, reducing energy costs and securing cleaner sources of supply.

2.0 Drivers of Transmission Investment

Transmission is an increasingly urgent issue at the state, regional, and federal levels because of a perceived need to maintain reliability and reduce costs, and because of transmission's potential role in meeting state energy goals, such as increased use of renewable energy sources. One perspective on the development of renewable energy, reliability, and other power system goals is that new, long-distance transmission lines are central to meeting these objectives. This perspective has resulted in a transmission planning process that is, almost by definition, focused solely on transmission solutions to meeting our energy needs.

An alternative view is that transmission-focused planning processes may not give enough consideration to non-transmission approaches to meeting energy needs. This view is illustrated by the reaction of the New York and New England Regional Transmission Operators (RTOs) to the "Joint Coordinated System Plan," which outlines massive transmission construction to bring Great Plains wind power to the East Coast at an estimated cost ranging from $49 billion to $80 billion. In the view of the northeastern RTOs, the plan was deeply flawed because it did not consider other –possibly less expensive– options, including New England wind resources, energy efficiency, demand response, and smart grid technologies, and building shorter transmission lines to renewable power in Canada.[1] Many states, from Vermont to Massachusetts, are dramatically increasing investments in energy efficiency and promoting other demand side energy resources like distributed generation and on-site combined heat and power systems. These growing parts of our energy system do not rely on power being transmitted but rather on using energy more efficiently and generating power on-site, and they have a direct and large impact on how our transmission grid is sized – or even whether lines should be built or expanded. However, while the RTOs from the Northeast are concerned about large transmission projects from the Midwest, there appears to be less interest on the part of those RTOs in addressing the current imbalances within the New England planning and tariff structure for reliability that favor traditional transmission over NTAs. If the Northeast's transmission planning structure is to give equal weight to non-transmission solutions to power system needs, the transmission planning process should be much broader than it currently is.

Traditional transmission drivers and new policy drivers are causing policy makers and transmission planners at all levels to reconsider the scope of the transmission planning process. Some of the traditional and new drivers of transmission investment include:

- *Grid reliability and load growth*: The transmission system is essential to regional electric reliability because it distributes power across regions, helping to balance energy demand with energy supply in real-time and to accommodate periodic peaks and troughs in system demand and power supply as

[1] Letter from Gordon van Welie, President and CEO, ISO New England, Inc. and Stephen Whitley, Present and CEO of New York Independent System Operation, to Joint Coordinated System Planning Initiative, February 4, 2009, http://www.nyiso.com/public/webdocs/services/planning/jcsp/2009_2_4_JCSP_Letter_FINAL.pdf

they occur. As new areas grow and power plants are built and retired, new transmission investments may be needed to keep the grid stable and reliable. However, efforts to slow the growth in energy consumption or load (MWh) and particularly peak demand (MW) through energy efficiency, demand response, or distributed generation can reduce the need for transmission upgrades.

- *Renewable power development*: Many states have passed mandates in the form of Renewable Portfolio Standards (RPS), requiring increasing percentages of renewable energy as part of the electricity mix. Many of the best sources of renewable power are located in remote areas. Unless there happens to be transmission located nearby, transmission lines need to be built to bring the power from the source to load centers. This an expensive cost of developing renewable energy that must be paid for either by the developer or the ultimate recipients, or it could be spread across all ratepayers in a region. Developing renewable energy sources is a real and important driver of transmission investment, but consideration needs to be given to the total cost of the delivered energy (renewables plus transmission costs).

- *Transmission economics*: The Energy Policy Act of 2005 embodies numerous provisions intended to increase investment in the transmission system, including transmission rate incentives that allow for a return on equity as great as 11 to 12.5 percent on transmission investments that have been developed through an open planning process and that increase reliability, reduce congestion, or both. This provision makes transmission a low-risk, high-return investment and has led to increased interest among utilities in developing new transmission. These rates of return are not available for non-transmission resources.

- *Climate change*: Significant reductions in greenhouse gas emissions over the coming decades will require fundamental changes in our energy system. Some solutions will require more transmission to be built. For example, large remote or off-shore wind resources, large power plants with carbon capture and sequestration, or other technologies could all require new investments in transmission infrastructure. Other solutions, such as retrofitting homes for energy efficiency or managing electricity consumption through demand response, will lower demand for transmission capacity. Combinations of energy efficiency and local, distributed renewable generation, such as photovoltaic power, that deliver the vision of a "zero-energy" building may reduce the need for long-distance transmission infrastructure.

- *Regulated utility ownership of transmission and renewables*: Regulated utilities are increasingly interested in owning and operating renewable power sources and the transmission infrastructure needed to deliver the power to load centers. In such a case, the utility would often be allowed to recover the project cost and earn a rate of return on their investment by rate-basing the investment and having ratepayers pay for the costs over time. While a utility may be in good position to navigate the political and regulatory hurdles and finance large projects, the utility would also have an incentive to maximize its capital investment in order to earn the largest return. This could have the effect of favoring high-cost projects to maximize the return on investment.

- *Economic development*: Both new transmission and renewables development (as well as energy efficiency and demand side investments) represent real, new economic development for a state or region. They can bring new construction, operation and maintenance jobs as well as potential manufacturing jobs. The economic development benefits, however, can have the effect of playing states or regions off against each other as choices are made on where to site new energy infrastructure. One state or region may see itself as a renewable energy supplier, another as the best location for transmission development, or potentially both. In addition there is an economic downside to new development if ratepayers bear an increased burden of paying for large, new projects. It is important to balance economic development opportunities and total ratepayer costs.

The planning process, markets, and payment schemes to address electric system reliability and assess the need for new transmission or NTAs, need to consider and balance this broad set of economic and environmental drivers.

3.0 New England Transmission Costs

In the context of electric reliability planning and transmission investments, it is important to understand transmission cost trends, because these are passed on to ratepayers and represent a significant source of higher electric utility rates and thus bills in recent years.

Trend data on transmission costs and rates are not readily available and require significant digging through utility and ISO New England websites and FERC databases.[2] ENE undertook an assessment of information in these databases. ENE's evaluation of transmission costs and rates raises important findings for further discussion and review:

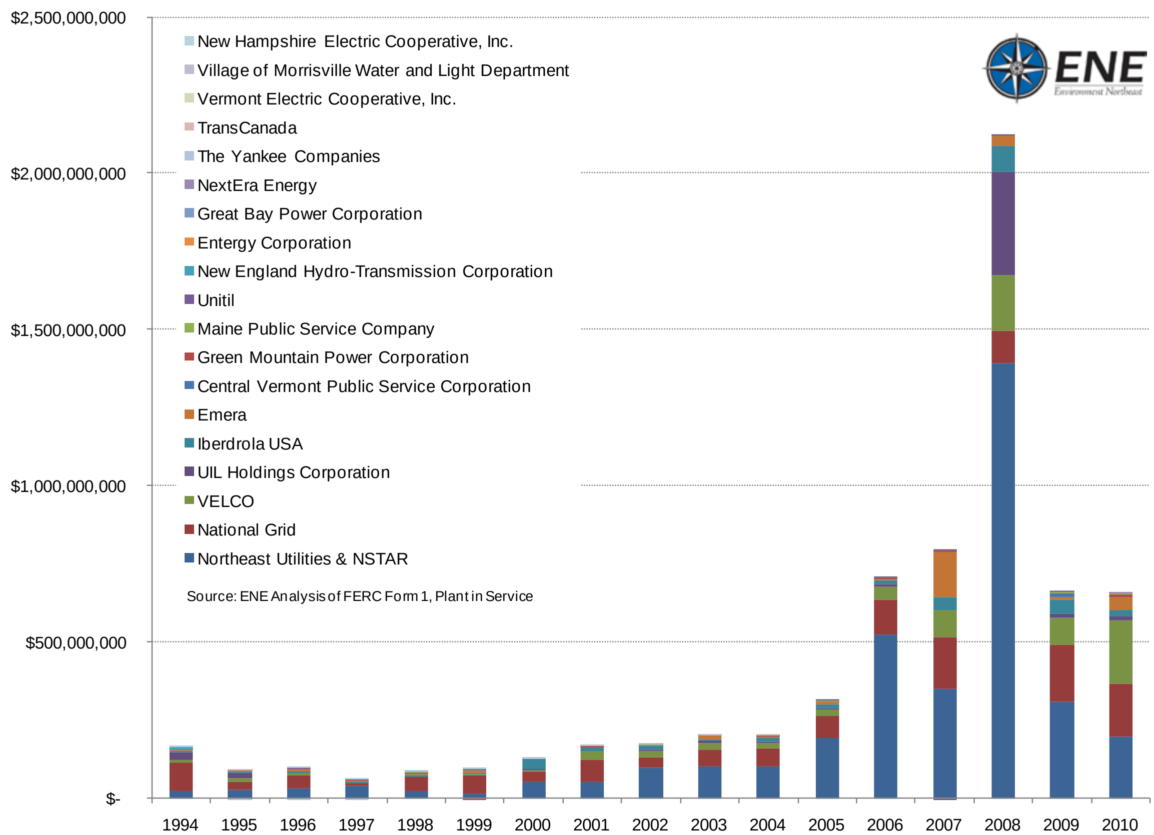
- New England transmission system expenditures have skyrocketed in the last ten years, with expenditures in real dollars up by 5 to 6 times their level in 2000 and up by about 17 times in 2008, with planned expenditures staying high in coming years. (See Figures 1 and 2. Note that distribution system expenditures have been essentially flat in comparison to transmission expenditures.)
- New England expenditures on transmission are growing at a radically steeper rate than those of the rest of the country (see Figure 2) and utilities have another $4.75 billion planned (see Figure 3).
- Transmission expansion and upgrades have contributed to a significant decline in electricity congestion costs (see Figure 8, but the cost of the transmission upgrades, based on rates paid by consumers, appears to be an order of magnitude higher than the congestion costs being paid in 2005.
- The merger of Northeast Utilities and NSTAR creates a huge entity in control of most recent (see Figure 4) and planned transmission investment as well as ~56% of existing miles of transmission.

[2] As a result of the difficulty of accessing relevant information, it is unlikely that, without improved transparency, the public and policy makers will gain a full understanding of these costs, trends and issues.

- The spending on transmission is clearly leading to significant increases in the transmission component of electricity rates, as seen in average rate information available for the Northeast Utilities companies (see Figure 5). Note, that this kind of historical rate component information is not readily available in most states. Current transmission rates vary some by utility in New England, but in 2011 most utilities appears to be charging transmission rates similar those in Connecticut (see Figure 6).

ENE used the Form 1 databases available from FERC to summarize transmission system expenditures in New England by parent company (Figure 1). This should provide a picture of the annual expenditures by utilities in transmission upgrades that are then paid for over time in transmission rates.

Figure 1: Total New England Transmission Expenditures by Parent Company (nominal) [3]

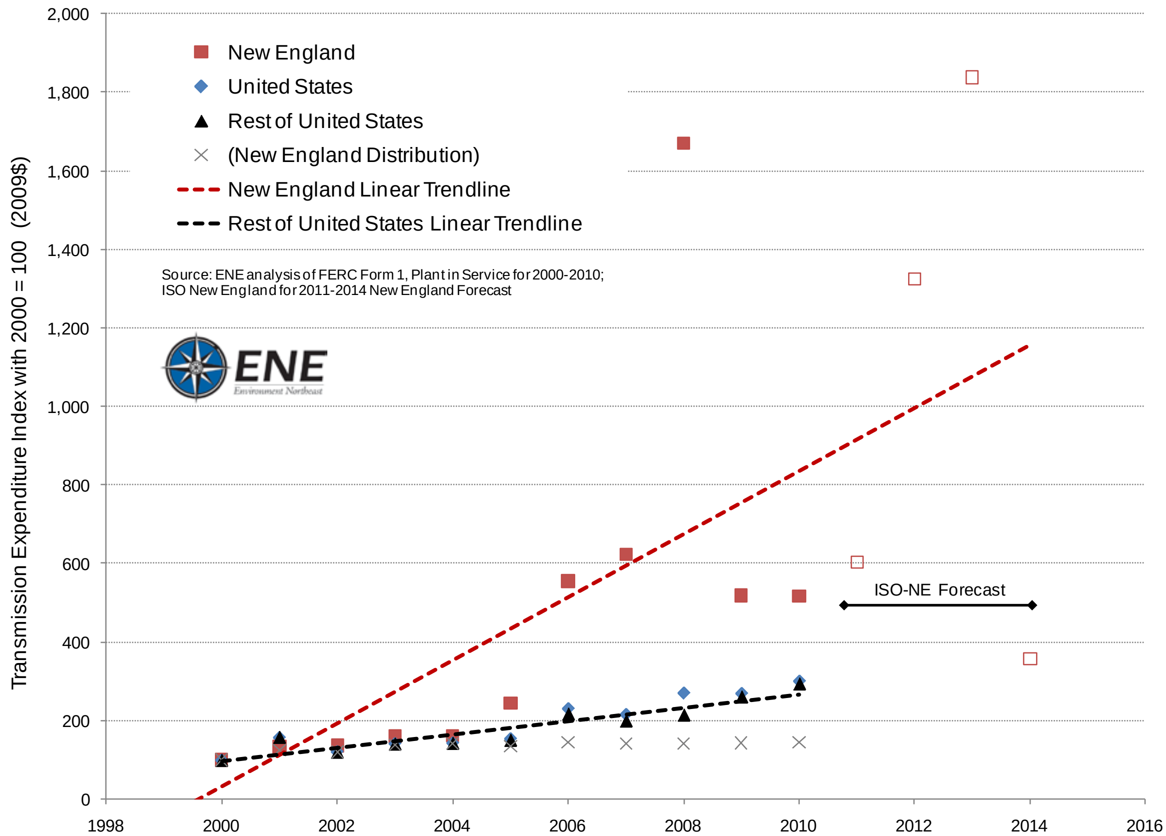


In order to assess how the spending in New England compares to the rest of the country, ENE also summarized national transmission expenditures from FERC data. Figure 2, below, compares New England expenditures to the rest of the country using an index with expenditures in 2000 equal to 100. This illustrates the rate of change on a consistent scale. New England expenditures have been and are anticipated to continue increasing at a rate that is significantly higher than the rest of the country. Figure 3 illustrates where companies have additional projects planned for coming years. ENE also compiled New England expenditures on the electric distribution system, and, as Figure 2 shows, this spending has

[3] See Appendix A for detailed utility expenditures by company as compiled by ENE using database queries of FERC Form 1, Total Transmission, Plant in Service.

been relatively stable. One would think that older infrastructure would be upgraded or invested in across the board, for transmission and distribution. However, state regulators have much more oversight of distribution system investments and have not granted the same rates of return for these investments.

Figure 2: Comparison of New England and US National Transmission Expenditures Since 2000 [4]



[4] ENE compared the annual transmission investments we compiled based on FERC Form 1 to those reported by EEI in their annual EEI Statistical Yearbook (Table 9.1: Construction Expenditures for Transmission and Distribution) and found that the data are similar (see Appendix A). EEI's data are based on a survey of their members, and they supplement the data they receive with FERC From 1 data if companies do not respond.

Figure 3: Planned New Transmission Expenditures to Address Reliability [5]

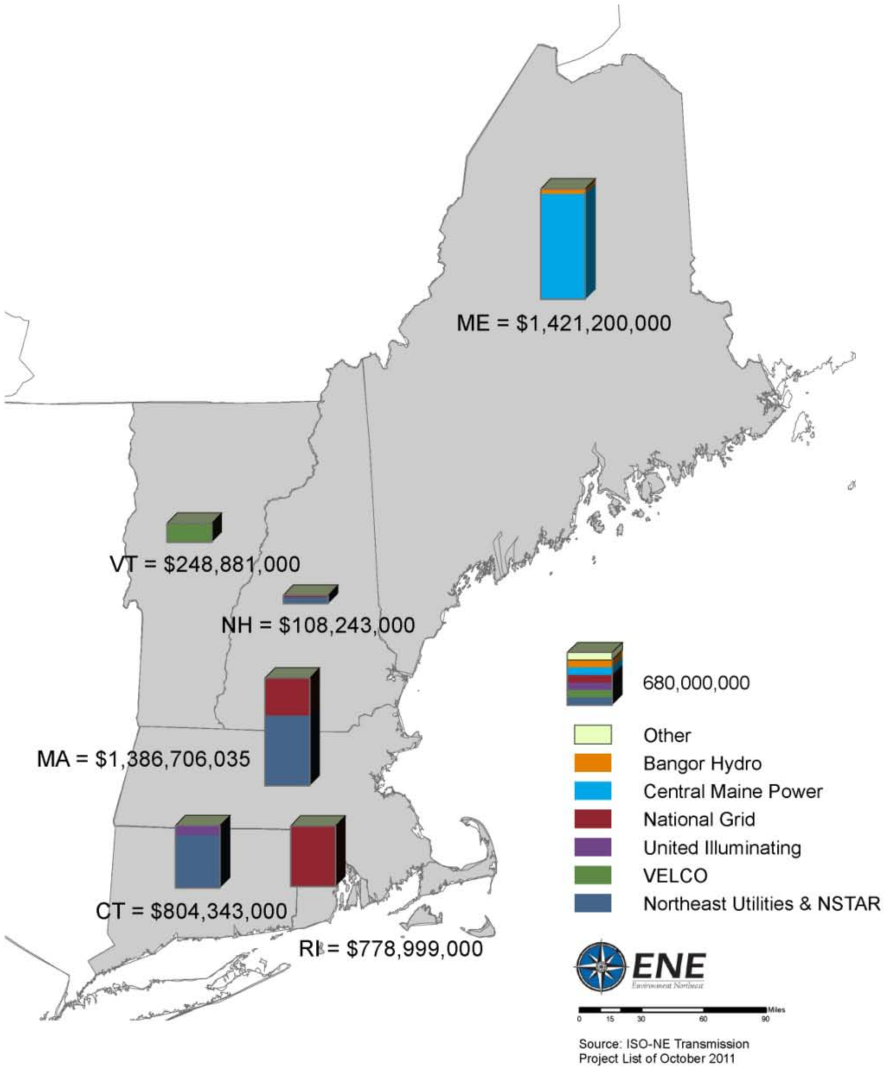
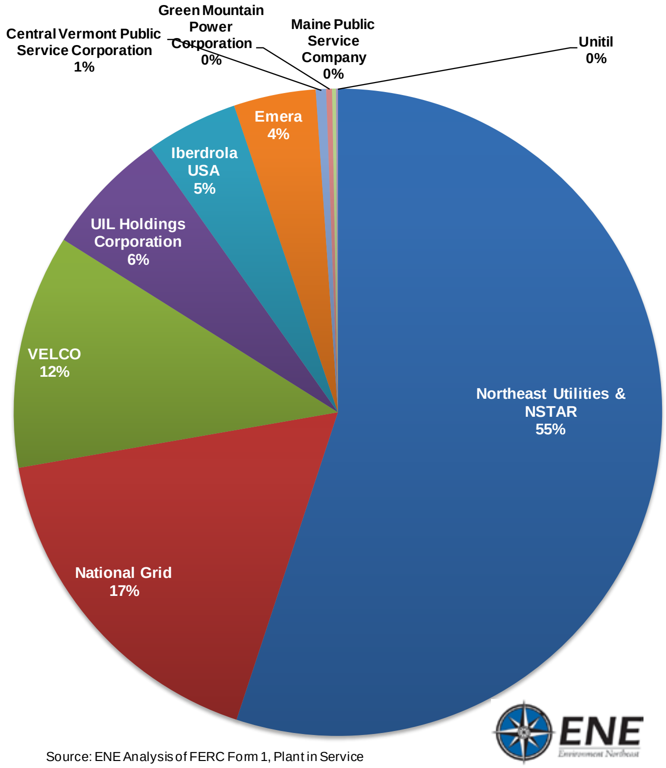


Figure 4 (below) provides a sense of which utilities in New England made the biggest investments in transmission infrastructure over the last decade.

[5] Total transmission project costs – by state and company - from ISO-NE RSP Transmission Project Listing – October 2010. Available on-line at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2010/index.html

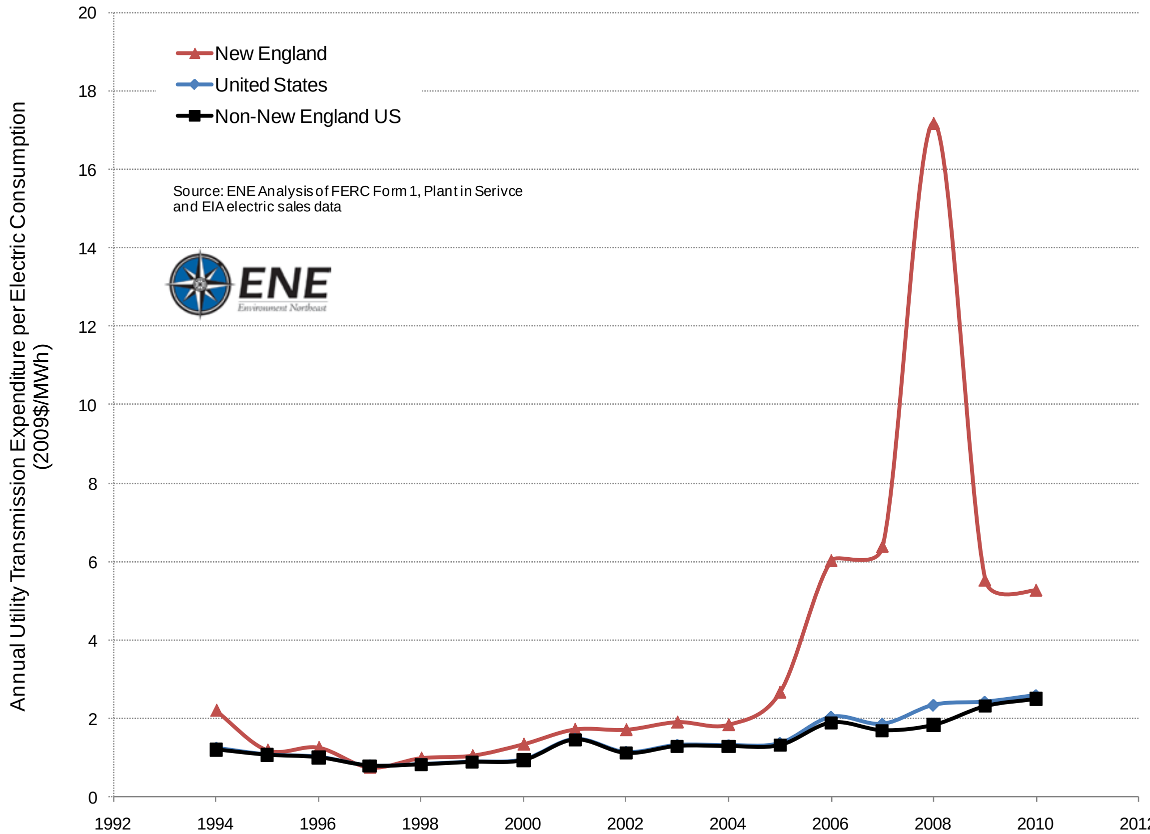
Figure 4: Percent of Total Transmission Expenditures from 2000-2010 by Parent Company [6]



In order to assess whether New England transmission expenditures had been historically low in relation to the rest of the country, we also looked at the rate of spending per unit of energy sold. As seen in Figure 5, below, New England has also been spending at a significantly higher rate using this metric.

[6] See Appendix A for total expenditures from 2000-2010.

Figure 5: Transmission Expenditures per Unit of Energy Consumed



Increased expenditures on transmission infrastructure are slowly but consistently increasing transmission rates in the region. Historical transmission rates are not readily available to the public. However, Northeast Utilities (NU) has provided ENE with data for its retail companies, which provide a picture of trends over the last ten years. NU's information is the only historical information ENE has access to at this time. As ENE understands it, NU's rates are similar to those of other utilities in New England. Figure 6 illustrates the increase in transmission rates, which have increased by about five times since 2000. Rates used to be under half a cent per kWh. They are up by over a cent and are projected to go up to almost two cents above where they were in 2000. The ENE initial projection in Figure 6 is based on ISO New England's forecast of the near-term rate increases all New England ratepayers will see for the portion of transmission costs that are paid consistently across the region (regional network service rate, a portion of the total transmission rate paid by customers). We have assumed that the difference between regional network service rate and the total transmission rate paid by consumers remains the same. As these data show, rates will continue to rise significantly to cover the additional expenditures in the past few years and future expansion of the transmission network.

Figure 7, also below, presents current residential transmission rates for most of the major utilities in New England, with consumers now seeing relatively consistent rates across the region.

Figure 6: Residential Transmission Rate Trend

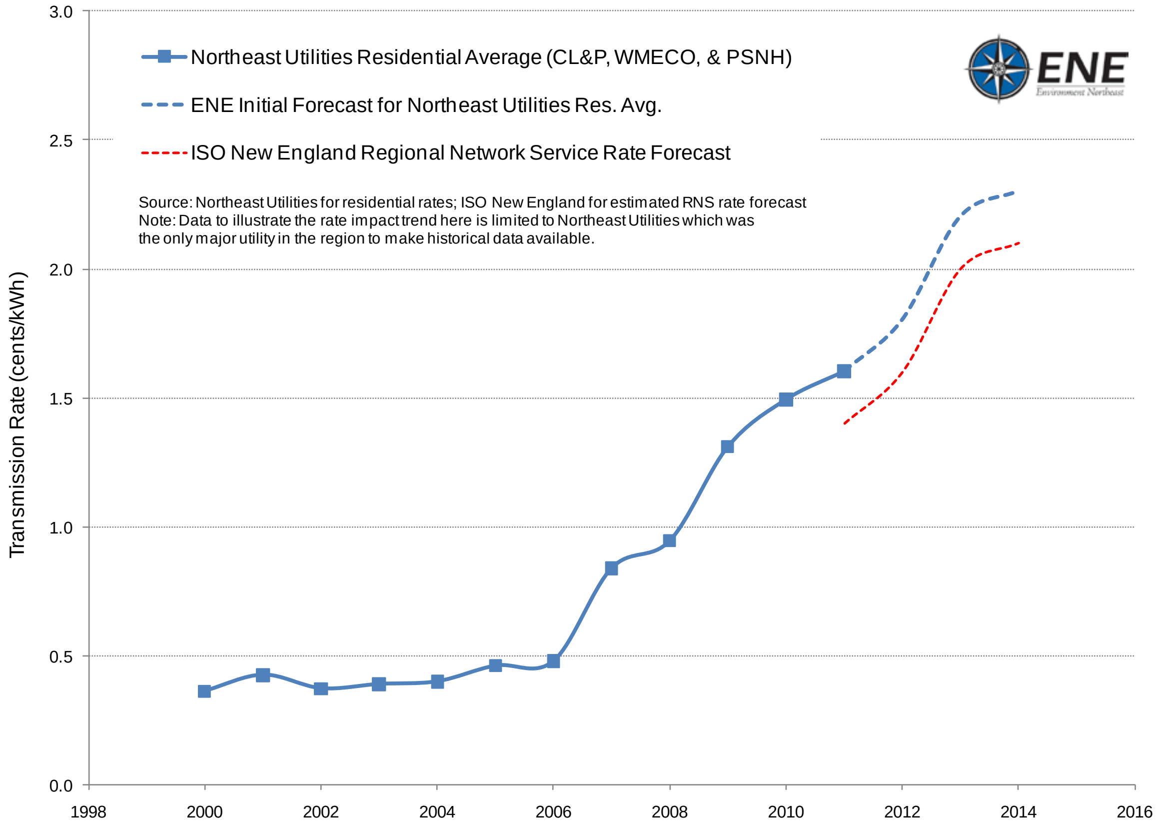
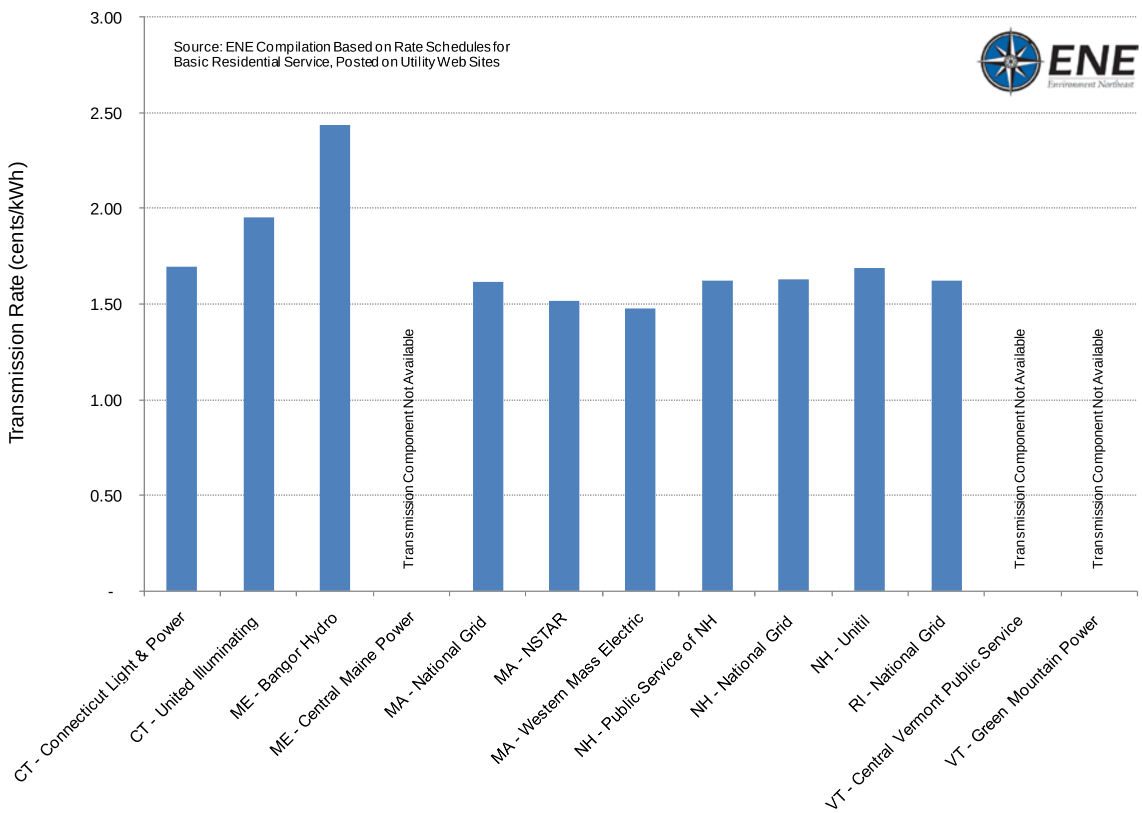
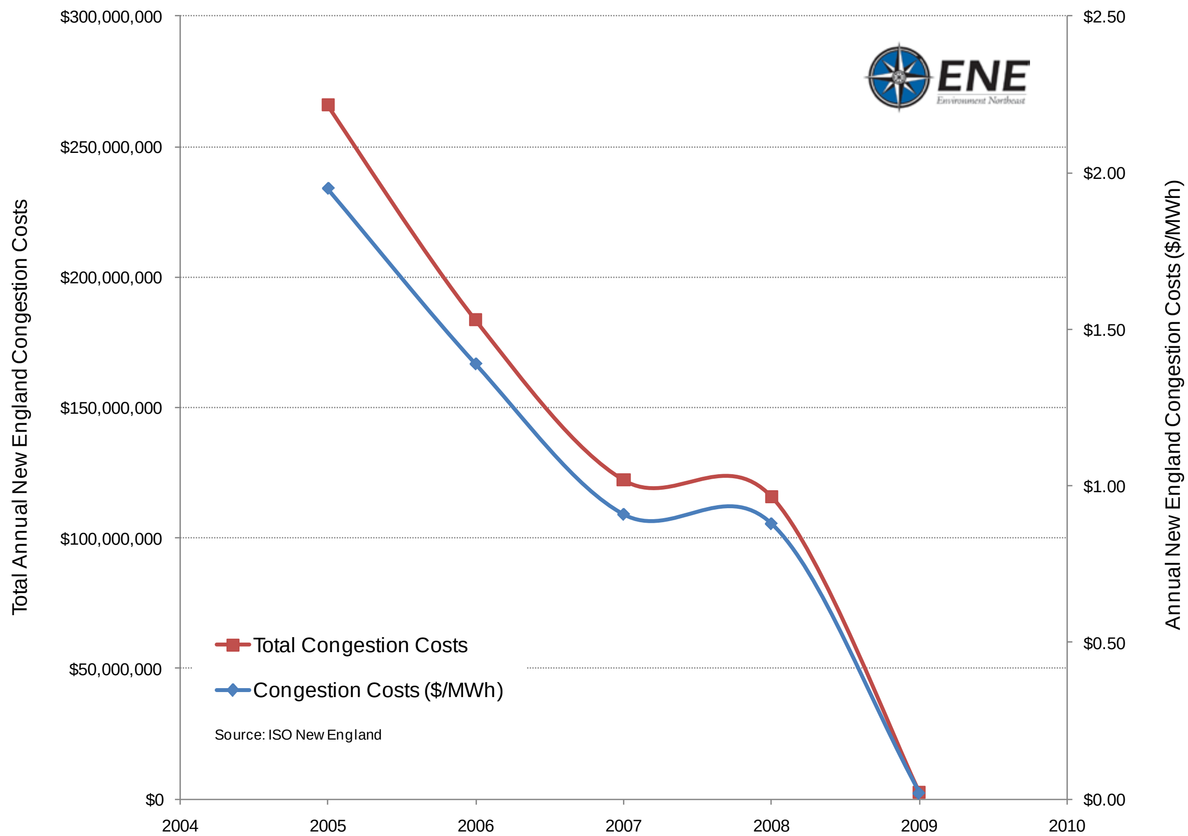


Figure 7: Current Residential Transmission Rates for Major New England Utilities



ISO New England and other stakeholders and policy makers note that the increase in transmission investments has essentially eliminated costs associated with transmission congestion in the region. As more transmission capacity is available, power prices in different parts of the region converge. However, our review of congestion cost trends indicates that while costs have essentially gone away, the cost of congestion to ratepayers in the region in 2005 appears to have been an order of magnitude lower than the costs now being paid for transmission (congestion costs of $2 to $2.5 per MWh vs. transmission costs of $20 to $25 per MWh). This means that the congestion-cost savings to ratepayers have not been large enough to compensate for the overall increases in expenditures on transmission, as some claimed they would. Figure 8 below illustrates the decline in congestion costs in both gross dollar terms and dollars per megawatt-hour ($/MWh) rates.

Figure 8: New England Congestion Costs from 2005 to 2009 [7]



Policy makers need to thoroughly investigate these trends and better explain why they are occurring; if they are just and reasonable; and whether policy changes should be made at the state and federal levels.

ENE has only begun to assess the drivers of increased transmission costs and rates, but some of the factors that may be contributing to skyrocketing transmission costs include:

[7] Congestion costs per MWh are from ISO New England (http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2011/final_vanwelie_2_12_11.pdf) and total annual costs were calculated by ENE using New England net energy for load numbers from ISO New England.

- Aging Transmission Networks: Many industry commentators suggest that the country and the region are behind in terms of upgrading old transmission infrastructure. However it is important to note that most of the large new projects in New England involve new infrastructure and not just replacement of older systems.
- Increases in Material Costs: The cost of building transmission infrastructure is on the rise, particularly costs of copper, aluminum, and steel. Inflation in material costs as well as labor and other drivers are presumably relatively consistent across the country and would not explain the significant differences in spending between New England and other regions.
- National Reliability Rules: Policy directives to FERC contained in the federal Energy Policy Act of 2005 and the related, new and more stringent FERC and NERC reliability requirements following the 2003 blackouts are likely a significant contributor to new transmission expenditures. However, policy makers and stakeholders should examine whether or not there are differences in the way planning or reliability rule interpretation is occurring in New England versus the rest of the country that could be contributing to higher expenditures in this region.
- New England Reliability and Transmission Planning Rules: ISO New England reliability planning and payment schemes exclusively favor transmission over other alternatives such as efficiency, demand response, and distributed generation which may offer lower cost reliability options. In addition, the socialization of costs across the region increasingly takes decision making out of state regulators' hands. And while they may find comfort in the fact that the costs of an individual project will be paid for by all states, regulators might not be taking into account the cumulative effect of all the new projects on rates region-wide. It also appears that FERC is not focusing on minimizing consumer costs as it moves forward with approving new rules and projects.
- Reducing Energy Prices through Reduced Congestion: Policy makers have long been told that more transmission capacity and the costs associated with it will be offset by lower energy prices as congestion declines in the region. The costs and benefits should be examined more closely, because ENE's initial comparison indicates that transmission costs are significantly higher than congestion savings.
- Transmission Return on Equity: The incentives FERC has approved for transmission in New England on the order of 13% return on equity, which is a hard-to-beat investment in this economic climate, are not serving consumer interests as transmission developers have an incentive to maximize large new expenditures on transmission and push for regional planning rules that advantage transmission over other resources.

State and federal regulators should carefully examine the transmission cost and rate trends identified here. These trends are influenced by a broader array of issues and policies than are discussed in this report, but considering how reliability and transmission planning is completed, paid for, and how other non-transmission resources fit into the system are all important pieces of that examination.

3.0 Regulatory Framework

Electric grid regulation is divided among federal, regional, and state authorities. The following discussion reviews the roles of the Federal Energy Regulatory Commission (FERC), the regional transmission organizations (RTOs) and state public utility commissions in transmission planning and cost allocation.

3.1 Federal Transmission Regulation

FERC's predecessor, the Federal Power Commission (FPC), was established in 1920 upon Congress' passage of the Federal Water Power Act. The 1935 Federal Power Act (FPA) gave the FPC jurisdiction over electric public utility[8] rates and accounting and transmission in interstate commerce.[9,10] The majority of FPC's duties were delegated to FERC upon the enactment of the 1977 Department of Energy Organization Act.[11]

Section 205 of the FPA, now codified as 16 U.S.C. § 824d, authorizes FERC to regulate "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges. . . ."[12] Under this section, public utilities must file transmission tariff schedules with FERC, and FERC has the authority—although characterized as "essentially passive and reactive"[13]—to prohibit unjust rates and undue discrimination for jurisdictional services. Section 206 of the FPA, codified as 16 U.S.C. § 824e, grants FERC broader discretion, for example, to remedy a rate, charge, or practice upon a finding that a "rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential. . . ."[14]

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[8] "Public utility" is defined as "any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter." 16 U.S.C. § 824(e). "Electric energy in interstate commerce" is defined as electricity that is "transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States." 16 U.S.C. § 824(c).

[9] Elizabeth Moler et al., *A Salute: 75 Years for the FPC and FERC*, 16 Energy L. J. 293, 293-4 (1995).

[10] Section 201(a)-(b) of the FPA, codified as 16 U.S.C. §§ 824a-b. Part II of the FPA does not apply to any other sale of electric energy. Section 201(b) of the FPA, codified as 16 U.S.C. § 824(b), states, in relevant part,

> The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

[11] Moler at 296.

[12] 16 U.S.C. § 824d(a).

[13] Stan Mark Kaplan and Adam Vann, *Electricity Transmission Cost Allocation*, CRS Report for Congress, 2 (2010) (citing *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

[14] 16 U.S.C. § 824e(a).

FERC's ratemaking jurisdiction under the FPA is limited to rates of public utilities for jurisdictional services.[15] The Court of Appeals for the District of Columbia Circuit has stated that "customers can take any FERC-jurisdictional service under a[n] open access tariff. . . . Customers must take non FERC-jurisdictional service . . . under a state tariff."[16] Therefore, detractors may argue that FERC cannot regulate the rates for demand response services for non-public utility or public utility providers because FERC's jurisdiction may not be extended to non-transmission alternatives[17] and should be analogous to the FPA's treatment of generators.[18]

However, FERC has already extended its jurisdictional reach over non-transmission alternatives, namely demand response and efficiency resources, in the Forward Capacity Market. In its Order No. 719-A, issued on July 16, 2009, FERC affirmed its jurisdiction set forth in Order No. 719 that required RTOs and ISOs to accept demand response resource bids. In Order 719-A, FERC points to its statutory authority to ensure "that rates and charges for jurisdictional sales by public utilities and 'all rules and regulations affecting or pertaining to such rates or charges' are just and reasonable."[19] Further, FERC cites Section 206 as the source for its "authority over rate and charges by public utilities for jurisdictional sales as well as 'any rule, regulation, practice or contract affecting such rates and charges' to make sure that they are just and reasonable and not unduly discriminatory or preferential."[20] According to Order No. 719-A, FERC's regulatory authority over public utility wholesale sales allowed it to determine that the wholesale electric market reflected actual conditions, and "that wholesale markets work best when demand can respond to the wholesale price. . . . Thus, the Commission began this proceeding with the goal of eliminating those barriers to demand response participation in the organized markets, and to ensure comparable treatment of all resources in these markets."[21] FERC has successfully defended the Installed Capacity Requirement under its broad authority to "identify practices that 'affect' public utility

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[15] *See Bonneville Power Administration v. FERC*, 422 F.3d 908, 918 (9th Cir. 2005).

[16] *Detroit Edison Co. v. FERC*, 334 F.3d 48, 51 (D.C. Cir. 2003).

[17] FERC recently determined that sales of pure demand response services, or the reduction in consumption of electricity, are outside of FERC's jurisdiction. *See*, *generally*, *EnergyConnect, Inc.*, 130 FERC ¶ 61,031 (2010). In *EnergyConnect, Inc.*, FERC explained that "[t]raditionally, jurisdictional facilities have been either physical facilities such as transmission lines or 'paper' facilities such as wholesale power contracts through which entities engage in wholesale power sales." *Id.* at 6. FERC stated that it did not "regard agreements to provide services from only demand response resources to be jurisdictional facilities because they involve agreements to reduce demand, i.e., agreements not to purchase electric energy under certain circumstances, rather than agreements to sell electric energy at wholesale." *Id.* at 7.

Significantly, however, FERC noted that entities solely providing demand response services are not precluded from FERC authority regarding FPA provisions concerning market manipulation, price transparency, and enforcement of violations. *Id.* at 8. In its decision, FERC directed EnergyConnect, Inc. "to revise its tariff to remove all references to provision of demand response services." *Id.* at 9.

[18] In his concurring opinion in *EnergyConnect, Inc.*, Commissioner Moeller states his opinion that "demand response providers could be public utilities to the extent that their activity involves the transmission of electric energy in interstate commerce." *EnergyConnect, Inc.*, 130 FERC ¶ 61,031 (2010) (Moeller concurring). Commissioner Moeller further clarifies that, "[u]nlike generating plants, which have an explicit statutory exemption from [FERC] jurisdiction (even if those plants are used to control the transmission of electric energy in interstate commerce), facilities that reduce demand are not explicitly exempt from Section 201." *Id.*

[19] Order 719-A, 128 FERC ¶ 61,059 (2009), at 27, fn 64 (citing 16 U.S.C. § 824d(a)).

[20] *Id.*

[21] *Id.* at 28.

wholesale rates under the FPA."[22] At issue in *Connecticut Dep't of Public Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009), *cert. denied*, 130 S. Ct. 1051 (2010), was whether FERC's review of the Installed Capacity Requirement exceeded its authority by regulating electrical generation facilities, which were required to bid into the Forward Capacity Market. The court found that FERC's review was within its jurisdiction over practices affecting wholesale rates.[23]

In Order 719-A, FERC states that demand response "affects public utility wholesale rates. . . ."[24] Ultimately, "because demand response directly affects wholesale rates, reducing barriers to demand response in the organized markets helps the Commission to fulfill its responsibility, under sections 205 and 206 of the FPA, for ensuring that those rates are just and reasonable."[25] Because the Forward Capacity Market is "a market subject to the Commission's exclusive jurisdiction,"[26] this determination regarding demand response is limited and narrowly focused—that is, simply reducing a barrier to participation in the market.[27] Therefore, even though FERC is explicitly denied jurisdiction over generators under Section 201(b), it may exercise its exclusive jurisdiction over market rules to cover bids from generators, demand response, and other demand-side resources like energy efficiency programs or investments.

Therefore, FERC should be able to address tariffs and cost allocations concerning non-transmission alternatives through its Section 206 authority, which FERC has cited in promulgating rulemakings, *inter alia*, mandating open access to the transmission system,[28] encouraging the creation of RTOs to operate the transmission system,[29] and establishing transmission planning principles, including cost allocation.[30] No party has succeeded in an FPA challenge to FERC's authority in promulgating these rulemakings.[31]

3.2 Regional Transmission Planning and Cost Allocation

Barriers to incorporate NTAs exist at the regional level. Under current rules and procedures, ISO-NE, the grid operator in the six New England states, does not provide cost support to NTAs. FERC and ISO-NE tariff rules would have to change in order to remedy this. The Energy Policy Act of 1992 created a class of wholesale generation to be regulated by FERC, which received new authority to push the electric industry toward increased competition.[32] FERC subsequently proposed rulemakings for

[22] *Id.*

[23] *Id.*

[24] Order 719-A at 30.

[25] *Id.* at 31.

[26] *Id.*

[27] *Id.* at 31-32.

[28] Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996) (codified at 18 C.F.R. pts. 35 & 385).

[29] Order No. 2000, 65 Fed. Reg. 810 (Jan. 6, 2000) (codified at 18 C.F.R. § 35.34).

[30] Order No. 889, 61 Fed. Reg. 21,737 (May 10, 1996) (codified at 18 C.F.R. pt. 37).

[31] Kaplan at 3.

[32] Moler at 296.

open-access transmission tariffs (OATTs) to address restructuring.[33] The Energy Policy Act of 2005 (EPAct '05) directed FERC to exercise its authority under the FPA to ensure that load-serving entities (LSEs) can "secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis. . . ."[34]

One reform that followed was FERC's Order No. 890 in 2007, revamping the OATT initially issued in 1996.[35] Order 890, intended to strengthen the *pro forma* OATT to ensure that it remedied undue discrimination, required transmission providers "to establish open and inclusive transmission planning processes for their own service areas, and to participate in regional transmission planning processes that would ensure cross-border concerns would be addressed."[36]

ISO-NE's current OATT requires that transmission planning complies with Order 890's principles of coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. To ensure compliance, ISO-NE has established a Planning Advisory Committee (PAC) that reviews and provides input on, for example, the development of the Regional System Plan, Needs Assessment, and Solutions Studies. When reliability needs are identified, ISO-NE and transmission owners develop transmission and transmission alternatives as a transmission backstop solution. Market responses—including those that clear the Forward Capacity Market—that ISO-NE and PAC determine to be sufficient to alter the need for a backstop solution are considered in Regional System Plan updates, but such backstop solution planning continues until ISO-NE makes a formal determination and notification that the reliability need has been addressed. Transmission owners subsequently submit their project proposals for technical review and apply for regional cost allocation. If an NTA solution is built it can lead to an adjustment of the reliability need, but cost allocation presents an almost insurmountable barrier for NTAs.

ISO-NE's OATT specifies cost allocation practices for, *inter alia*, reliability upgrades, economic upgrades, and generator interconnection. For example, reliability transmission upgrades listed in the Regional System Plan that include transmission at 115 kV or higher and meet the criteria of being a Pool Transmission Facility (PTF) are fully allocated across all ISO-NE load. Any remaining localized costs are allocated to the zone where the costs are incurred. Schedule 12 of the ISO-NE OATT details the upgrades, with the formula of cost allocation discussed in Schedule 9.[37] Market efficiency transmission upgrades (METU) must meet certain requirements to be considered for the Regional System Plan; however, a METU that is a planned part of the Regional System Plan can receive regional cost support if it is 115 kV or above and meets the PTF criteria. If the METU is unplanned pursuant to the Regional System Plan, as well as merchant transmission, it is paid for by the project sponsors.[38] Meanwhile, 100%

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[33] *Id.*

[34] 16 U.S.C. § 824q.

[35] Jay Morrison, *EPAct '05 Implementation: Is FERC in Full Compliance?*, 28 Energy L. J. 631, 644 (2007).

[36] *Id.* at 645.

[37] ISO-NE's OATT is available at its website at http://iso-ne.com/regulatory/tariff/index.html.

[38] *Id.* at Attachment K, Attachment N II.D., and Schedule 12.

of direct generator interconnections are paid for by the interconnecting generator. However, if the upgrade would provide benefits to the ISO-NE system, the upgrades are treated as reliability upgrades.[39]

ISO-NE has clarified that its OATT does not currently support non-transmission alternatives. In a brief filed in Docket No. 6860 before the State of Vermont Public Service Board, ISO-NE distinguished a Gap RFP issued in Connecticut in 2003 for a mix of demand side management and demand response that received regional cost support as a short-term solution.[40] Shortly after ISO-NE issued the Gap RFP, it applied for a change to Market Rule 1 of Section III of its OATT.[41] ISO-NE specified in its brief that a Gap RFP "may be issued when ISO determines that a region may have potential critical near-term power supply reliability problems for which no Participant has proposed or committed to implement a viable solution, and the Gap RFP must solicit load response and supplemental generating resources to maintain near-term reliability in such region."[42] Market Rule 1 now provides that such costs would be allocated to the reliability region affected by the Gap RFP, not the entire region. "In other words, the costs of such resources are not pooled; they do not receive regional cost support."[43] ISO-NE further asserted that "[t]he suggestion that ISO should have issued or administered an RFP . . . as a non-transmission reliability solution runs counter to FERC policy of encouraging market responses and competitive solutions to identified system needs."[44] ISO-NE further cited Section 15.5 of the Restated NEPOOL Agreement (RNA), referencing Schedule 12 of the OATT, specifically the 100th Agreement amending the RNA. As described above, the categories of transmission upgrades and corresponding cost allocation treatments specified "that only transmission upgrades qualify as PTF."[45]

In presentation materials prepared for the 2010 NECPUC Symposium by Stephen J. Rourke, ISO-NE Vice President, System Planning, ISO-NE stated the following:[46]

- ISO's role is to ensure a reliable transmission system and to administer fair and efficient markets
    - ISO does not have the authority to conduct integrated resource planning for the region, or to approve regional funding for NTAs through the transmission tariff.

[39] *Id.* at Schedule 11, Section 5.

[40] Reply Brief of ISO-New England Inc., PSB Docket No. 6860 at 10 (December 17, 2004).

[41] *Id.*

[42] *Id.*

[43] *Id.*

[44] *Id.* at 11.

[45] *Id.* at 12-13.

[46] Stephen J. Rourke, *Supplemental Information, 2010 NECPUC Symposium*, Slide 11 (May 18, 2010) (available at http://iso-ne.com/regulatory/tariff/index.html).

- ISO's regional planning process, including economic study results, provides information and analysis to stakeholders without infringing upon state authority over integrated resource planning

- Policy makers can create incentives or disincentives for different types of resources

ISO-NE, therefore, does not currently provide regional cost support for non-transmission alternatives. However, the Planning Advisory Committee has recently initiated a conceptual study aimed at determining whether NTAs can be analyzed and situated at an earlier stage of the needs assessment process. The study will include analytical modeling in the current Vermont-New Hampshire study and is expected to present results in the second quarter of 2011.[47]

In 2010, a Settlement Stipulation was filed by parties in the Maine Power Reliability Project (MPRP) proceeding. (ENE was a party.) By virtue of Order Approving Stipulation in 2008-255, the non-utility group – the E4 Group – has access to funding to retain "expert assistance in order to participate in local, regional and possibly national fora where transmission planning and cost allocation is evaluated and adopted."[48] Going forward, the E4 group will employ the funds to increase its understanding the relevant issues, processes, and procedural vehicles with a goal of advancing the interests of Maine transmission consumers and address NTAs.

In 2005, Vermont's General Assembly passed Act 61 to direct regulators and utilities to advocate at ISO-NE, in proceedings before FERC, and in all other relevant venues, to support an efficient reliability policy that achieves "regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis."[49] Moreover, for reliability-related projects in Vermont, "regional financial support should be sought and made available for transmission and for distributed resource alternatives to transmission on a resource-neutral basis."[50] Thus, policy consensus across the ISO-NE region may encourage ISO-NE to reconsider its OATT to include NTAs

On June 17, 2010, FERC issued a Notice of Proposed Rulemaking, proposing reforms to FERC's transmission planning and cost allocation policy. The NOPR sets out several proposals, including a requirement for all transmission providers in the development of a regional transmission plan that would identify what transmission facilities and non-transmission alternatives would be needed to meet customers' needs; a requirement that all transmission providers specify in their OATT procedures for evaluating transmission projects proposed for public policy purposes; a requirement to reform OATTs to remedy undue discrimination against non-incumbent transmission developers; a requirement

[47] *See* Marianne Perben, *Introduction to Nontransmission Alternatives, Planning Advisory Committee* (October 21, 2010) (available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/oct212010/nta.pdf).

[48] MPUC Order Approving Stipulation in Docket No. 2008-255 (June 10, 2010)

[49] Act 61, Section 8(6), 2005 Vermont General Assembly.

[50] *Id.* at Section 8(4).

for transmission providers to coordinate with neighboring regions for interconnection purposes; and a requirement that transmission providers propose cost allocation methodologies for interregional and intraregional cost allocation that comply with certain principles.[51] The results of the proposed rulemaking may address the current cost allocation practices for non-transmission alternatives, but tariff changes at both the ISO-NE and FERC levels may still be required to allow non-transmission alternatives funding parity with regional transmission projects.

3.3 State Regulation

The majority of the transmission planning process occurs at the regional level, and only after project proposals are approved by ISO-NE do such projects enter state processes for municipal input and siting prior to construction. States such as Rhode Island,[52] Massachusetts,[53] and Maine[54] require that siting applications include a study of alternatives. New Hampshire requires its site evaluation committee to consider available alternatives.[55] As detailed below, northeastern states have demonstrated interest in incorporating NTAs in planning, but they have not overcome the barriers at the regional level.

The Connecticut Department of Public Utility Control (CT DPUC) has specifically clarified that transmission owners are not tasked with identifying non-transmission alternatives.[56] Instead, Connecticut General Statutes § 16a-7c authorizes the Connecticut Energy Advisory Board, a statutorily created stakeholder board, to issue reactive requests for proposals, triggered when a transmission owner files an application with the Connecticut Siting Council, as well as proactive requests for proposals for energy related needs. The reactive RFP process has been widely viewed as ineffective because the late timing and short review timeline are large hurdles for proponents of alternatives to overcome in demonstrating reliability needs.[57] The proactive RFP process, however, allows the CEAB to solicit a notice of intent to respond from market participants, and an evaluation of these responses allows the CEAB to initiate the RFP process. Any project chosen by the CEAB would need to meet a standard of reliability that is comparable to that identified by ISO-NE in determining its backstop transmission needs.[58] The CT DPUC has committed to working with the CEAB to better define this process in anticipation of a proactive RFP in conjunction with ISO-NE's Greater Hartford Needs Assessment.[59] It should further be noted that any NTA project identified by the state would still need to undergo the ISO-NE reliability study process and would not receive regional cost support under its OATT. New comprehensive energy

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[51] *See*, *generally*, 131 FERC ¶ 61,253 (2010).

[52] *See* Rhode Island General Laws § 42-98-8(7).

[53] *See* Massachusetts General Laws c. 164, § 69J.

[54] *See* 35-A Maine Revised Statutes Annotated § 3132(2-C).

[55] *See* New Hampshire Revised Statutes Annotated § 162-H:16.

[56] *See* Final Decision, at 26, Docket No. 10-02-07 (DPUC Review of Integrated Resource Plan) (September 15, 2010).

[57] *See* CEAB Technical Paper: State Electric Resource Planning Enablers and Energy Organization Structure Enablers, at 501-502, Docket No. 10-02-07 (DPUC Review of Integrated Resource Plan) (April 27, 2010).

[58] *See* Integrated Resource Plan for Connecticut, at 4-7,8, Docket No. 10-02-07 (DPUC Review of Integrated Resource Plan) (January 1, 2010).

[59] *See* Final Decision, at 26-27, Docket No. 10-02-07 (DPUC Review of Integrated Resource Plan) (September 15, 2010).

legislation in Connecticut, P.A. 11-80, *An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future*, would require that, as of March 2012, certain annual filings by electric transmission and generation service companies to the Siting Council must now identify to the commissioner of the new Department of Energy and Environment Protection any potential reliability concerns during the forecasting period.[60] Fifteen days later, the commissioner may issue a request for proposal to seek alternatives to address the reliability concern, including, when relevant, energy efficiency measures or generation; a decision by the commissioner not to issue such request for proposal must include a rationale for such decision.[61]

Meanwhile, Vermont has established, through a Vermont Public Service Board order and a docket settlement and founded in Vermont's Act 61, the VSPC and an associated planning process "designed to facilitate full, fair and timely consideration of cost-effective non-transmission alternatives to new transmission projects. The Committee increases collaboration among utilities, lengthens the planning horizon to be sure there is time to fully consider all alternatives, increases transparency of the process, and involves the public in decisions about alternatives."[62] As part of the process, VELCO performs a 20-year transmission analysis and initiates a coordinated ten-step plan that evaluates NTAs as part of the state's least-cost integrated planning process with input and involvement from the VPSC, the Energy Efficiency Utility, utility companies, other stakeholders, and the public.[63]

Clearly a number of states the region have expressed interest in better incorporating NTAs into system reliability planning. Still, the states have not been able to overcome the hurdle at the regional level –the fact that they do not receive regional cost support under the ISO New England OATT.

NTAs face barriers at the three jurisdictional levels of transmission planning: federal (FERC); regional (ISO-NE); and, state (PUCs). Regulators and stakeholders have shown some interest in and progress toward incorporating non-transmission solutions in the way the power system needs are assessed and purchased. The ISO-NE planning processes have two primary flaws. First, the forecast of future load is based on anticipated economic conditions, weather, federal appliance and lighting standards, and existing demand response resources, but it does not consider policies promoting energy efficiency or other demand side measures. The consequence of erroneously high load growth is a transmission system that is over-built and unnecessarily costly. The second flaw, as discussed above, is that the transmission planning process typically excludes non-transmission solutions to power system needs. Furthermore, without regional cost support, non-transmission solutions will almost always look less attractive than traditional transmission solutions. States only pay a portion of transmission costs while having to fund 100% of any alternative (see Figure 7). In order to ensure that NTAs receive full and equal consideration as potential resources, regulations need to be changed to include them in planning and payment processes.

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[60] *See* Public Act 11-80, Section 97, Connecticut General Assembly.

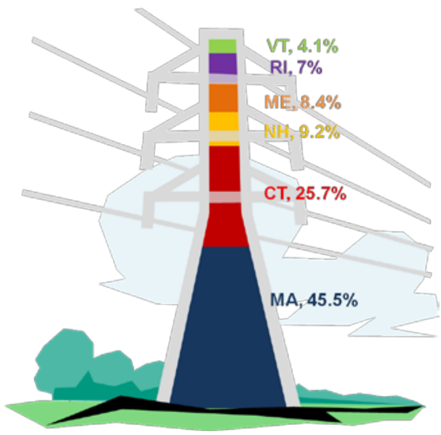
[61] *See* Public Act 11-80, Section 98, Connecticut General Assembly.

[62] "A New Approach to Planning for the Future of Vermont's Electric System," Vermont System Planning Committee (available at http://www.vermontspc.com).

[63] *See*, *generally*, Memorandum of Understanding, Docket No. 7081 (Investigation into Least-Cost Integrated Resource Planning for Vermont Electric Power Company, Inc.'s Transmission System) (June 20, 2007).

Figure 9: The Transmission Cost Allocation Dilemma
States pay only a portion for transmission projects vs. the full cost of NTAs

Transmission Line Costs Are Paid for by All States **vs.** **Non-transmission Alternative** Costs Are Borne Entirely by One State



4.0 Case Studies – Examples of the Current Hurdles for NTAs

Tremendous opportunities exist to use non-transmission alternatives, including energy efficiency, distributed generation, and demand response, to meet our energy needs. In some cases, NTAs can defer or avoid upgrades to the transmission system by freeing up capacity at a lower overall cost to ratepayers. However, as outlined above, the current transmission planning and cost allocation processes at the regional and federal levels essentially lock out efficiency, distributed resources, and demand response. The challenge in reforming the transmission planning and payment processes is to create a level playing field for non-transmission alternatives so they can help meet the region's energy needs in the most cost-effective, reliable, and environmentally sound manner.

There is hope to do this, as case studies from the state level demonstrate. Recent attempts have been made by states or utilities in Maine, Vermont, Rhode Island, and Massachusetts to address the inadequacies in the transmission planning and cost allocation processes. These states provide examples of the processes and institutions that can be established to address non-transmission solutions. Each of these approaches is new, and non-transmission projects are only beginning to be identified and developed as a result of these efforts.

The case studies discussed here, and in greater detail in Appendices B through F, include efforts to assess and incorporate both non-transmission and non-distribution alternatives, as we believe that while the scale of the problem between transmission and distribution capacity may differ, the solutions are similar.

4.1 Maine Power Reliability Project

In March 2007, Central Maine Power (CMP) and ISO-NE initiated a study evaluating the reliability of Maine's bulk transmission system. Based on the findings of the study, CMP went to the

Maine Public Utilities Commission (Commission) for approval of the $1.5 billion Maine Power Reliability Project (MPRP), the most expensive infrastructure project in Maine history.[64] As proposed, the MPRP consisted of approximately 350 miles of 115 kV and 345 kV transmission lines and infrastructure intended to increase the capacity and transfer capability of Maine's transmission system and support the development of renewable energy resources in western and northern Maine and Canada.[65] Maine ratepayers would only pay for 8 percent of the project costs, with the rest paid for by ratepayers in the other New England states.

Over the course of the next year, the Commission received and approved more than 180 petitions to intervene in the case, many of which were intended to ensure that the ambitious MPRP would minimize both cost to ratepayers and environmental impact. The interveners argued that the CMP and ISO-NE transmission planning process and cost allocation methodology creates an incentive to maximize the construction of regional transmission facilities and does not give enough emphasis to non-transmission approaches to meeting Maine's energy needs.[66] In particular, GridSolar, LLC filed an alternative to the MPRP with the Commission that would meet Maine's reliability needs through the use of distributed solar generation in combination with small back-up generators and investments in a smart electric grid.

In 2010, the Commission approved a multi-party agreement in the MPRP proceeding. The agreement introduced a blend of tradition transmission, distributed generation, smart grid technology, and increased investments in energy efficiency. While the plan included the use of distributed solar generation and increases investments in energy efficiency and weatherization, it also included the build-out of much of CMP's originally proposed expanded high-voltage transmission system at a cost estimate of $1.4 billion.[67] This experience illustrates the state and stakeholders can make an effort to include NTAs, but it also shows that a strong barrier remains. In a system in which costs for traditional transmission upgrades are socialized across the region and costs for non-transmission alternatives are not, it is nearly impossible for state regulators to choose the non-transmission solution. They are compelled to choose the solution that ensures reliable utility service while minimizing the economic impact on in-state ratepayers.

4.2 Northwest Vermont Reliability Project

In January 2005, the Vermont Public Service Board (Board) approved Vermont Electric Company's (VELCO) Northwest Reliability Project, a major transmission upgrade to Vermont's transmission system originally estimated to cost $120 million. But, when the costs for the 345kV line from West Rutland to New Haven quickly ballooned to over $228 million, the Board questioned how thoroughly VELCO had examined NTAs. Opponents of the project argued that distributed generation and targeted efficiency could provide the same reliability at lower cost, and an analysis of NTAs concluded that a combination of targeted energy efficiency and new generation could address the reliability need at 5.19% less than the cost of the transmission project. However, due to deficiencies in

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[64] *Order,* Docket No. 2008-156, Maine Public Utilities Commission (June 30, 2009)

[65] *Id.*

[66] *Brief of Industrial Energy Consumers Group.* Maine Public Utilities Commission, Docket No. 2008-255. March 17, 2010.

[67] *Stipulation*, Docket No. 2008-255, Maine Public Utilities Commission (May 7, 2010).

the early consideration of non-transmission alternatives, the Board ultimately concluded that it had "no viable option but to approve a transmission solution for a reliability problem that might have been either deferred or more cost-effectively addressed through demand-side measures or local generation, if there had been sufficient advance planning by VELCO and its owners."[68] Although the alternative proposal for 74 MW of targeted efficiency had a lower expected total social cost, Vermont ratepayers would have to pay the total cost of the NTA. With the traditional transmission solution the states chose, Vermonters only paid 7 percent of the transmission solution, with the rest of the cost shared by ratepayers throughout New England.

To avoid a repeat of this dilemma, the Vermont Legislature passed Act 61 to establish a process through which transmission planning would incorporate consideration of NTAs, particularly in the early stages of the process. Act 61 directs regulators and utilities to support reliability planning policies that achieve "regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis."[69] At about the same time that the legislation was passed, the Vermont Public Service Board directed VELCO to evaluate NTAs as part of a least-cost integrated planning process with input and involvement from a wide range of stakeholders.[70]

4.3 Marshfield, Massachusetts

The $4 million Marshfield Energy Challenge in Marshfield, MA was administered and partially funded by NSTAR, the regional utility, with additional funding from the Massachusetts Technology Collaborative, and the state's economic development agency. The initiative's goal was to determine whether energy efficiency, clean distributed generation, and demand response could reduce the town's peak electricity demand and defer distribution system upgrades. In 2008 summer peak was forecast to exceed the capacity of the existing system, but a targeted load reduction of 2 MW could defer the need for line upgrades, saving customers approximately $150,000 for each year the upgrade could be deferred.[71]

To achieve the necessary load reduction, NSTAR offered free energy assessments to households and businesses, 500 free smart thermostats that would give NSTAR the ability to raise household temperatures up to 4 degrees during peak demand, and 30 solar PV systems.[72] While the Marshfield Energy Challenge attempted to reach all of the town's residents, it made special efforts to get property owners on the congested electrical circuit to participate. Participation in NSTAR's energy efficiency programs within Marshfield increased by 1,300 percent in the first 9 months of the pilot, and the

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[68] Order, Vermont Public Service Board, Docket No. 6860 (January 28, 2005).

[69] Act 61, Section 8(6), 2005 Vermont General Assembly.

[70] *Id.* at Section 8(4).

[71] Marshfield Pilot Design Report for NSTAR Electric & Gas Corporation and Massachusetts Technology Collaborative. Prepared by Rocky Mountain Institute, Energy & Environmental Economics, Inc., Freeman, Sullivan, & Co. December 18, 2007

[72] Driving Demand for Home Energy Improvements. Fuller, M., C. Kunkel, M. Zimring, I. Hoffman, K.L. Soroye, and C. Goldman. LBNL-3960E. September 2010

pressure on the affected circuit was sufficiently reduced to defer the planned upgrade.[73] The Marshfield Energy Challenge demonstrated that a combination of targeted energy efficiency and distributed generation can defer distribution system upgrades. However, Massachusetts still faces barriers to fully integrating non-wires alternatives into the state's distribution system and should support rule changes at the MA Department of Public Utilities and ISO-NE that require consideration of non-wires solutions to electric system needs.

4.4 Rhode Island System Reliability Procurement

Rhode Island's Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006 contains an important and innovative requirement as part of its overarching least cost procurement mandate.[74] RI's electric utilities are required to develop a "system reliability plan" that strategically considers an array of customer-sited energy resources to maximize their benefit to RI's energy system. These "non-wire alternatives" (NWAs) include cost-effective energy efficiency measures targeted to reduce peak loads; distributed generation at or near loads; and demand response measures that reduce the peak loads on the electricity grid. These strategies would be combined with actions than can squeeze more out of the existing distribution system. The utility is asked to assess whether an array of such resources could be deployed to avoid dirtier "peaking" generators and enable the utility to defer distribution (and potentially transmission) system investments. Deferring distribution system investments could provide savings over time for customers and could lower the volatility and cost uncertainty of the larger energy and capacity markets in New England by securing sources of energy supply and capacity from in-state resources.

Over a period of 18 months, the state's Energy Efficiency and Resource Management Council (Council), in cooperation with National Grid, developed a process for revising the system reliability procurement standards and a framework for considering NWAs as possible solutions to planning and reliability issues, which was approved by the Rhode Island Public Utilities Commission on June 7, 2011. The Council's objective is to establish a procedure and funding options for systematically identifying customer-side and distributed resources that, if cost-effective, defer or avoid distribution upgrades, improve system reliability, and provide for better utilization of distributed resources. The goal is also to effectively anticipate new technologies (such as electric vehicles and energy storage) and become a model for other states and utilities.

National Grid has also undergone a lengthy and comprehensive internal planning process to incorporate the consideration of NWA options into its Distribution and Transmission planning. This procedure has been signed approved by National Grid for its own use by the Vice Presidents of Transmission Asset Management, Distribution Asset Strategy and Policy, Energy Products, and Smart Grid.

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[73] *Id.*

[74] R.I.G.L. § 39-1-27.7 (2006)

4.5 New York Independent System Operator, Comprehensive Reliability Planning Process

The New York Independent System Operator (NYISO) Comprehensive Reliability Planning Process (CRPP) is a unique "all-resource" process that is significantly different from other regions' planning processes. The CRPP is unique because it evaluates generation, transmission, and demand response solutions to an indentified system reliability need on a comparable basis and gives preference to market-based solutions. The CRPP is conducted in a multi-step process. In the first step, NYISO identifies long-term (10-year) reliability needs based on existing reliability criteria. If any reliability criteria are not met in any future year, NYISO analyzes whether additional resources and/or transmission expansion is needed to meet the requirements and determines the first year of need for those additional resources or transmission. In the second step, NYISO solicits solutions from the marketplace and directs transmission owners to prepare regulated backstop solutions for each identified need. Both market-based and regulated solutions are open to all resources including transmission, generation, and demand response.

NYISO evaluates all of the proposed solutions to determine whether they are viable and will meet the identified need in a timely manner. Following its evaluation of all of the proposed solutions, NYISO prepares the CRPP. The CRPP identifies all proposed solutions that NYISO has found to meet part or all of the identified need. If a market-based solution has been proposed, the CRPP will state so. If not, NYISO determines whether a regulated backstop solution is needed and will request that the Responsible TO(s) proceed with regulatory approval and development of the backstop solution.

In 2008, NYISO identified a reliability need in 2012 due to a statewide capacity deficiency and a local transmission constraint. In response to its solicitation, NYISO received over 3,800 MW of market-based solutions, including 2,430 MW of non-transmission solutions, sufficient to defer the initial reliability need until 2013 when complemented by a merchant transmission solution.[75]

NYISO and the New York Public Service Commission (PSC) provide similar cost allocation methodologies for transmission and non-transmission solutions, respectively, making it less likely that transmission will be chosen as a solution to address reliability needs assuming non-transmission is more cost-effective, as it usual proves to be. However, only transmission solutions are eligible for return on equity as provided by FERC. Generation and demand response solutions are not eligible for return on equity. The New York model may provide an important example to New England policy makers and stakeholders who are considering how to incorporate NTAs into planning and cost allocation mechanisms.

5.0 Policy Recommendations

Non-transmission alternatives cannot solve every electric reliability problem, but there are significant opportunities to incorporate NTAs into transmission planning in a real and comprehensive way that could lower costs to customers. Doing so requires new rules and policy changes at the state, regional, and federal levels.

[75] NYISO White Paper. Transmission Expansion in New York State. November 2008.

In summary, the following barriers need to be addressed in order to fully integrate NTAs into transmission planning:

- *The Assessment of Need Ignores Planned NTA Investments*: Planners do not fully incorporate approved state efficiency and demand-side policies and plans into their long-term system planning models and processes. This has the effect of increasing the size of the reliability concern and potentially overbuilding the transmission system.

- *ISO-NE Transmission Planning Rules Do Not Embrace NTAs and Exclude NTAs from Receiving Any Cost Allocation*: There is an opening for NTA proponents to identify potential alternatives to transmission, but because there is no way to pay for those alternatives, few are brought to the table and none are selected. Even if an NTA project within a state could clearly be employed at a lower cost than a traditional one, a state would never choose to use and pay for the NTA option. This is because, under the current regional planning and payment system, the state's ratepayers would have to pay the full cost of the NTA while traditional transmission project costs would be allocated across the region.

- *Utility Business Models are Built on Increasing Capital Investments in Transmission and Not on Building and Owning NTAs:* Transmission and distribution utilities are almost all fully regulated, and the model on which they make money is driven by the return they are allowed on capital investments – essentially transmission and distribution, or steel and wires in the ground or through the air. They currently are not allowed to own NTA-type projects and make a similar return on them. A utility might make a modest return on efficiency program management, but the return is smaller than for a transmission investment (i.e. 5-8% vs. 13%)

ENE believes these barriers can be overcome and that a combination of state and regional policy changes could deliver a new set of transmission planning and cost allocation rules that would provide a level playing field for non-transmission alternatives. The following is an initial framework of recommended policy changes that ENE plans to discuss with state policy makers and other stakeholders. At this time, we have chosen not to focus on reform of NERC and FERC policies and rules, as we anticipate that it may be easier for FERC to approve some proposed changes at the ISO/RTO level as additional pilots before requiring them nationwide. However, most of what we propose below in relation to ISO planning and cost allocation could also be adopted by FERC more broadly for all jurisdictions.

5.1 Outline of Regional and State Policy Changes

1) Reform ISO New England Transmission Planning & Cost Allocation Rules

    a. Reliability Assessments:

        i. ISO-NE should seek input from each member state's public utility commission on the long-term state policy for energy efficiency and other demand-side programs, as well as the degree to which and locations in which those policies and programs are anticipated to reduce demand

ii. ISO-NE should incorporate this input into its modeling process for establishing where reliability constraints exist. (Note that to the extent there is uncertainty associated with demand-reduction projections, modeling exercises should be well equipped to handle uncertainty, which currently exists with other inputs such as weather and economic forecasts.)

iii. Other estimates of state and federal policy impacts should also be incorporated, such as generation additions and retirements.

b. Identification of Reliability Solutions

i. Non-transmission alternatives should be included on an equal footing with transmission system proposals to address reliability needs. Similar to the New York process, the need should be identified and then solutions of all types should be solicited from the market (going well beyond the current process).

ii. In all of the New England states, energy efficiency programs are now centrally coordinated and planned through annual or multi-year, state-wide plans prepared by program administrators, often with input and review from a stakeholder council or board, and approved by the state PUC. With this structure in place, ENE recommends that the efficiency proposals for increasing reliability should be made on a state-by-state basis, under the oversight of the PUCs, and honoring the existing efficiency program implementation and approval process.

iii. ISO needs to do a better job describing the reliability concern and what amount and types of NTAs could address that concern.

iv. Transmission and NTA reliability solutions should be compared on an equal basis in terms of cost – i.e. on a net present value basis – and the lowest cost and reliable solution should be chosen.

v. The impact of transmission and NTA solutions on the environment should also be assessed and reported, with an opportunity for state regulators to disqualify specific projects that are inconsistent with a state's environmental goals (i.e. climate change, air quality, land use, etc).

vi. Proposals that are hybrids of transmission and NTA technologies and programs should also be considered, which might allow for the reliability need to be addressed with a smaller transmission facility investment along with an NTA solution.

vii. NTAs would need to demonstrate and ensure that the energy and demand savings planned are actually delivered with a thorough evaluation, monitoring, and verification system utilized (i.e. built on current and updated evaluation, monitoring, and verification requirements for demand side resources)

c. Recovery and Allocation of Costs for Reliability Solutions

    i. Reliability upgrades that would require a transmission system solution eligible as a Pool Transmission Facility and thus have their costs allocated across the region should be eligible for cost recovery under ISO New England's tariffs. This should apply whether the reliability upgrade is a transmission solution or an NTA solution.

    ii. NTA solutions should have costs recovered through transmission charges, and costs should be allocated across the ISO region, as they are for transmission solutions.

2) State Reform of Utility Roles and Incentives

a. State policy makers should consider providing utilities a role in delivering the NTA solutions so that utility business models and incentives are aligned with maximizing consumer value.

b. In a number of states, utilities administer energy efficiency programs and have a natural opportunity to propose targeted expansions of those programs to deliver an NTA solution; however, state policy makers may want to consider a comparison of the performance based incentives utilities receive for efficiency programs with the return they make on transmission investments and consider making adjustments so that the opportunity for return on an NTA is equal to a traditional transmission investment, including by reducing the generous return utilities are currently receiving on transmission investments.

c. State policy makers could consider allowing utilities to own portions of NTA solutions such as metering and demand response controls or small distributed generation, and treat the investments as rate based capital investments; however, state policy makers should also consider changing utility incentives to focus on delivering energy services rather than maximize capital investments

d. Utilities should not be the only parties that could propose NTA solutions, but ENE proposes that state policy makers should identify ways to encourage utilities to be partners in delivering a lower cost and more diversified energy system rather than opponents.

3) Regional Planning and Rule Development:

a. State regulators should have a more significant role in developing suggested rule changes, conducting regional energy planning, and generally leading where the region is going in developing the electric system of the future. The current system appears to be overly dominated by industry stakeholders and ISO New England, with FERC not focused enough ratepayer costs.

b. Changes to the planning and rule making structure could take many forms and require significantly more discussion, but could include giving NESCOE a larger role, changing the ISO New England board and oversight structure, or forming a regional electricity regulatory and planning compact among the states.

5.2 Policy Implementation Recommendations

Implementation of these state and regional reforms would best be accomplished in a coordinated fashion across New England. State policy makers should be the ones to adapt and propose these reforms to stakeholders, ISO, FERC and other relevant entities. State policy makers represent all regional stakeholders, and a group like NESCOE or NECPUC – through which policy makers from each state can coordinate – is probably the best entity to develop a regional proposal that could then be fed into the NEPOOL, ISO New England, and FERC regulatory processes.

6.0 Conclusion

Planning a clean, affordable and reliable energy system is crucial to the Northeast's economic and environmental health. ENE's analysis shows that transmission is an increasing cost burden on regional ratepayers, and there are many factors driving these costs, as well as the need to consider transmission development in the future. Case studies and policy analysis further demonstrate that current planning processes at the state, regional and federal levels do not give full and equal consideration to goals such as cost control and clean energy development, nor to all solutions that could achieve those goals.

Among the primary solutions that ENE believes deserve better consideration are non-transmission alternatives, such as energy efficiency and demand response, which could reduce the need for more expensive projects. ENE contends that NTAs have a significant role to play in keeping our electric system reliable and also keeping costs low for the region, but case studies show that they are not adequately used or evaluated. ENE sets forth a list of recommendations that policy makers, particularly at the state level, should deliberate with stakeholders in order to develop a new set of coordinated regional policies that will help the Northeast develop and maintain a clean, affordable and reliable electric system.

Appendix A: Additional Transmission Cost Information

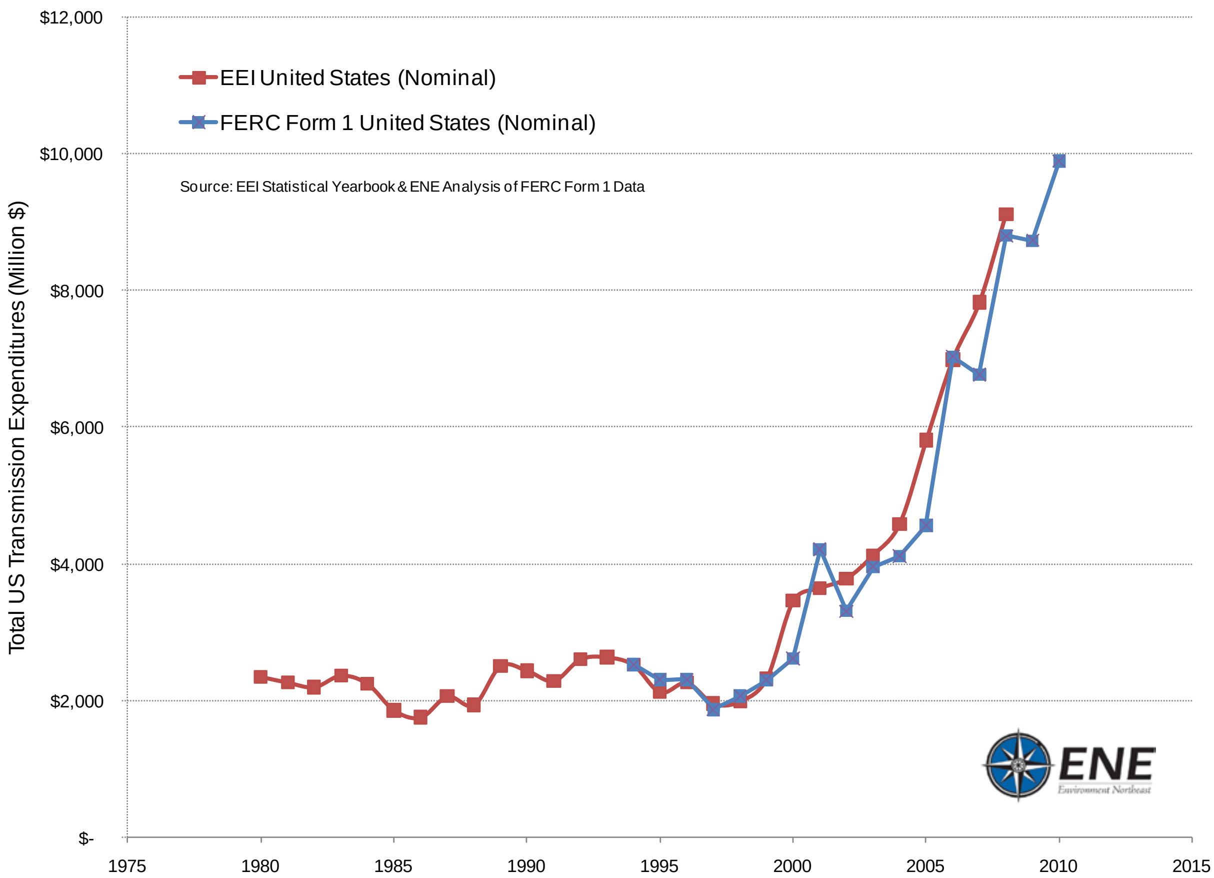
FERC Form 1, Transmission Expenditure Summary by Company

New England Annual Transmission Additions
ENE Analysis of FERC Form 1, Plant in Service, Total Transmission

ID	Parent Company	Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
25	Central Vermont Public Service Corporation	Central Vermont Public Service Corporation	704,854	982,436	1,570,179	1,456,155	2,713,402	775,703	982,152	1,716,256	1,720,493	1,955,329	2,227,017	1,556,195	1,429,431	3,140,003	1,020,400	12,990,889	2,857,961
37	Central Vermont Public Service Corporation	Connecticut Valley Electric Company Inc.	-	-	61,534	18,960	-	5,287	-	-	-	-							
11	Emera	Bangor Hydro Electric Company	3,371,823	4,468,501	8,317,100	4,306,936	6,538,595	11,459,463	3,480,779	1,778,750	412,614	11,633,245	1,474,994	6,148,924	3,041,142	143,286,687	31,023,971	6,657,905	41,453,688
185	Entergy Corporation	Vermont Yankee Nuclear Power Corporation	1,003	-	-	-	-	-	-	-	-								
60	Great Bay Power Corporation	Great Bay Power Corporation	65,033	(61,062)	(1,621)	-	284,478	-											
61	Green Mountain Power Corporation	Green Mountain Power Corporation	769,845	787,257	531,311	3,757,121	1,091,234	(66,612)	339,066	804,430	1,341,876	335,526	2,338,565	1,061,122	678,206	966,764	961,279	1,173,022	7,869,001
200	Iberdrola USA	Aroostook Valley Electric Company			-	-													
23	Iberdrola USA	Central Maine Power Company	4,337,244	4,667,971	2,494,847	2,707,062	1,433,326	1,216,847	26,226,181	9,110,592	9,099,652	2,454,095	13,379,541	11,701,223	14,679,279	41,386,528	84,332,796	44,549,845	20,636,193
90	Iberdrola USA	Maine Electric Power Company, Inc.	-	-	19,106	315,784	108,636	-	2,233,900	148,734	62,006	630,493	243,796	49,105	28,430	-	130,087	285,783	74,343
231	ISO New England Inc.	ISO New England Inc.																	
91	Maine Public Service Company	Maine Public Service Company	247,431	350,469	192,981	250,688	574,148	1,624,684	473,475	1,515,600	1,444,673	263,563	259,093	739,031	364,225	197,244	618,479	3,562,060	2,699,184
92	Maine Yankee Atomic Power Company	Maine Yankee Atomic Power Company	-	-	-														
13	National Grid	Blackstone Valley Electric Company	802,454	(575,256)	125,326	186,562	35,761	252,769	-										
47	National Grid	Eastern Edison Company	226,001	148,698	103,486	695,676	783,978	76,668	-										
59	National Grid	Granite State Electric Company																	
93	National Grid	Massachusetts Electric Company	16,781	(381)	536,887	632,179	(415,378)	34,047	115,854	2,347,651	4,652,858	6,041,120	5,674,723	5,418,455	(369,740)	2,895,005	2,650,421	1,038,392	872,440
104	National Grid	Montaup Electric Company	3,294,307	639,278	427,593	664,391	432,861	941,745	3,219										
416	National Grid	Nantucket Electric Company																	
110	National Grid	New England Electric Transmission Corporation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	National Grid	New England Hydro-Trans. Elec. Co., Inc.	12,710,650	-	-	439,725	-	-	-	-	-	-	-	1,745,810	-	6,752,711	2,844,368	344,681	1,791,621
113	National Grid	New England Power Company	33,461,741	20,601,505	22,891,908		40,945,105	50,767,600	31,833,407	65,516,009	23,991,976	42,406,081	40,197,088	55,302,041	108,642,257	145,551,971	64,974,859	172,120,526	113,951,908
116	National Grid	Newport Electric Corporation	203,154	71,930	352,792	119,253	4,733	91,931	14,066										
107	National Grid	The Narragansett Electric Company	42,424,889	5,853,634	16,509,452	3,351,596	509,643	3,821,908	2,445,583	3,630,091	8,373,181	7,927,725	12,292,437	6,955,695	638,517	8,503,766	31,788,587	7,873,872	51,541,108
112	New England Hydro-Transmission Corporation	New England Hydro-Transmission Corporation	6,942,901	-	-	52,275	-	-	-	-	-	-	-	-	-	-	-	-	-
204	New Hampshire Electric Cooperative, Inc.	New Hampshire Electric Cooperative, Inc.	51,625	19,435	4,408,430	367,201	52,578	28,948	87,803	-	-								
435	NextEra Energy	New Hampshire Transmission, LLC																	749,463
208	NextEra Energy	W. F. Wyman Unit No. 4 - Composite Data (100%)	-	-															
14	Northeast Utilities & NSTAR	Boston Edison Company	3,042,070	14,524,165	18,396,813	13,670,719	14,620,270	4,154,844	32,546,606	16,932,257	63,501,338	13,246,403	3,686,726	20,958,824	142,191,330				
15	Northeast Utilities & NSTAR	Cambridge Electric Light Company	2,634	-	103,938	192,662	21,845	-	-	2,548,746	(2,694,600)	538,189	10,177,276	4,735,771	(167,112)				
16	Northeast Utilities & NSTAR	Canal Electric Company	27,455	18,037	-	271,338	3,375	-	-	-									
34	Northeast Utilities & NSTAR	Commonwealth Electric Company	6,957,144	5,632,500	3,195,641	1,342,607	7,228,133	271,283	7,070,440	8,387,980	5,047,963	6,699,967	4,770,246	6,079,409	3,242,612				
39	Northeast Utilities & NSTAR	Connecticut Light and Power Company, The	7,155,591	6,470,795	2,411,667	17,396,128	1,829,828	1,620,054	8,213,739	19,009,857	14,301,961	26,942,596	82,630,174	131,419,325	342,180,563	199,016,602	1,134,778,107	97,942,508	77,733,965
66	Northeast Utilities & NSTAR	Holyoke Power and Electric Company	-	-	-	3,164	-	-	-	-	-	-	-	50,789	-	-	1,896,344		
67	Northeast Utilities & NSTAR	Holyoke Water Power Company	-	62	-	96,157	-	-	-	15,068	-	-	116,040	29,370	7,515	403,059	1,042,180		
118	Northeast Utilities & NSTAR	North Atlantic Energy Corporation	-	121	-	857,307	-	-	-	628,016	(4,152)								
309	Northeast Utilities & NSTAR	NSTAR Electric Company														97,358,398	155,851,601	119,318,698	67,169,298
146	Northeast Utilities & NSTAR	Public Service Company of New Hampshire	1,497,253	321,915	6,879,696	720,008	584,213	3,051,759	3,473,511	1,684,730	11,022,839	47,789,698	(6,200,377)	17,692,794	28,148,871	47,024,498	82,848,400	64,235,280	29,036,319
100	Northeast Utilities & NSTAR	Western Massachusetts Electric Company	2,609,710	335,858	193,372	5,804,691	95,039	6,294,185	397,454	2,920,077	3,498,614	4,629,380	6,402,314	10,688,367	9,800,164	8,124,630	17,308,252	26,145,020	22,563,847
419	Omya, Inc.	Omya, Inc.																	
38	The Yankee Companies	Connecticut Yankee Atomic Power Company	8,610	(28,067)	(654,259)	(905)	-								-				
124	TransCanada	Ocean State Power	-	-	-	-	-	-	15,100	87,350	1,405,182	3,696	-	-	-	-			
125	TransCanada	Ocean State Power, II	-	-	-		-	-	-	-	-	-	-	-	-	-			
179	UIL Holdings Corporation	The United Illuminating Company	22,502,110	15,997,731	2,591,097	538,951	543,824	(78,299)	1,521,714	861,043	4,311,377	7,305,266	4,116,078	4,689,453	6,913,408	(3,285)	329,053,907	11,661,559	12,489,107
53	Unitil	Exeter & Hampton Electric Company	269,527	71,460	278,861	122,174	306,634	83,246	193,235	458,774	-								
54	Unitil	Fitchburg Gas and Electric Light Company	173,000	208,150	721,715	214,614	141,347	122,440	510,363	54,340	56,219	915,439	1,045,829	7,728	1,445,888	186,122	5,282	43,964	54,666
290	Unitil	Unitil Energy Systems, Inc.																	
35	Unitil	UNITIL Power Corp.	11,251	100,241	2,819	77,413	8,083	95,224	328,662	217,144	-								
180	Unitil	UNITIL Power Corp.	-	-		-													
29	VELCO	Citizens Utilities Company	6,261,810	9,610,726	3,054,738	819,066	2,780,919	4,281,332	3,442,594	6,110,861	5,968,861	2,226,048	43,338						
183	VELCO	Vermont Electric Power Company, Inc.	2,757,463	976,013	4,114,576	1,124,539	694,322	2,882,645	1,102,129	20,565,644	14,486,722	18,944,671	16,000,706	24,053,029	3,140,781				
184	VELCO	Vermont Electric Transmission Company, Inc.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
320	VELCO	Vermont Transco LLC													39,376,429	86,745,069	178,087,792	89,381,741	203,656,045
247	Vermont Electric Cooperative, Inc.	Vermont Electric Cooperative, Inc.						-	4,308	8,151		51,738	3,215,277						
224	Village of Morrisville Water and Light Department	Village of Morrisville Water and Light Department			878,848	17,955	30,444	12,592	5,020	-	26,364	4,834							
198	Yankee Atomic Electric Company	Yankee Atomic Electric Company	-	-	-														
New England Total			162,910,264	91,194,232	100,501,632	62,489,142	83,981,385	93,822,293	127,069,262	168,959,171	172,926,991	202,944,093	204,092,880	311,112,450	705,411,996	791,535,772	2,121,217,112	659,325,745	656,900,347

Parent Company	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Northeast Utilities & NSTAR	21,291,857	26,303,553	31,181,117	40,354,882	24,382,712	15,392,125	51,701,752	52,027,731	95,573,837	99,846,234	101,584,398	191,674,649	525,403,743	351,927,167	1,393,724,684	307,641,506	196,503,429
National Grid	93,141,977	26,739,408	40,937,544	5,989,382	42,295,703	55,886,968	34,412,129	71,493,751	37,018,015	56,374,926	58,164,248	68,421,991	108,911,034	163,703,453	102,258,235	181,377,471	168,057,257
VELCO	9,019,273	10,586,739	7,169,314	1,942,594	3,475,241	7,163,977	4,544,723	26,676,505	20,454,583	21,169,719	16,044,044	24,053,029	42,517,210	86,745,069	178,087,792	89,381,741	203,656,045
UIL Holdings Corporation	22,502,110	15,997,731	2,591,097	538,951	543,824	(78,299)	1,521,714	861,043	4,311,377	7,305,266	4,116,078	4,689,453	6,913,408	(3,285)	329,053,907	11,661,559	12,489,107
Iberdrola USA	4,337,244	4,667,971	2,513,953	3,022,846	1,541,962	1,216,847	28,460,081	9,259,326	9,161,658	3,084,588	13,623,337	11,750,328	14,707,709	41,386,528	84,462,883	44,835,628	20,710,536
Emera	3,371,823	4,468,501	8,317,109	4,306,936	6,538,595	11,459,463	3,480,779	1,778,750	412,614	11,633,245	1,474,994	6,148,924	3,041,142	143,286,687	31,023,971	6,657,905	41,453,688
Central Vermont Public Service Corporation	704,854	982,436	1,631,713	1,475,116	2,713,402	780,990	982,152	1,716,256	1,720,493	1,955,329	2,227,017	1,556,195	1,429,431	3,140,003	1,020,400	12,990,889	2,857,961
Green Mountain Power Corporation	769,845	787,257	531,311	3,757,121	1,091,234	(66,612)	339,066	804,430	1,341,876	335,526	2,338,565	1,061,122	678,206	966,764	961,279	1,173,022	7,869,001
Maine Public Service Company	247,431	350,469	192,981	250,688	574,148	1,624,684	473,475	1,515,600	1,444,673	263,563	259,093	739,031	364,225	197,244	618,479	3,562,060	2,699,184
Unitil	454,578	379,851	1,003,495	414,201	456,064	300,910	1,041,150	730,258	56,219	915,439	1,045,829	7,728	1,445,888	186,122	5,282	43,964	54,666
New England Hydro-Transmission Corporation	6,942,901	-	-	52,275	-	-	-	-	-	-	-	-	-	-	-	-	-
Entergy Corporation	1,003	-	-	-	-	-	-	-									
Great Bay Power Corporation	65,033	(61,062)	(1,621)	-	284,478	-											
NextEra Energy	-	-															749,463
The Yankee Companies	8,610	(28,067)	(654,259)	(905)	-								-				
TransCanada	-	-	-	-	-	-	15,100	87,350	1,405,182	3,696	-	-	-	-			
Vermont Electric Cooperative, Inc.						-	4,308	8,151		51,738	3,215,277						
Village of Morrisville Water and Light Department			878,848	17,955	30,444	12,592	5,020	-	26,364	4,834							
New Hampshire Electric Cooperative, Inc.	51,625	19,435	4,408,430	367,201	52,578	28,948	87,803	-	-								
New England Total	162,910,264	91,194,232	100,501,632	62,489,142	83,981,385	93,822,293	127,069,262	168,959,171	172,926,991	202,944,093	204,092,880	311,112,450	705,411,996	791,535,772	2,121,217,112	659,325,745	656,900,347

Comparison of EEI Data to ENE Analysis of FERC Form 1



Appendix B

Case Study: Maine Power Reliability Project

Overview

Partly in response to the August 14, 2003 blackout that swept across the Midwest and Northeast United States and Ontario, Canada, Congress enacted the Energy Policy Act of 2005 requiring, among other things, the development of mandatory and enforceable electric reliability standards. Until recently, the nation's electric transmission system relied on voluntary compliance. The FERC designated NERC (North American Electric Reliability Corporation) as the official reliability organization for the U.S. and gave NERC legal authority to enforce reliability standards on all owners and operators of the transmission system.

In response to the new reliability standards Central Maine Power (CMP), the owner of Maine's bulk transmission system that serves over 560,000 homes and businesses, launched the Maine Power Reliability Project ("MPRP") in 2006 to assess reliability needs, evaluate solutions, and make investments in the grid to ensure reliable service.

CMP worked with ISO-NE to identify transmission needs and evaluate different solutions. They began by developing 10-year forecasts for electricity demand and compared those to the system's capacity. CMP and ISO-NE finished the needs assessment in June 2007 and concluded that the Maine transmission system does not have adequate capacity to meet the NERC reliability standards. CMP, it should be noted, was not an unbiased participant in this planning process, as it would be the likely owner of any required transmission upgrades.

The needs assessment indicated that additional 345 kV and 115 kV lines, transformers, and related equipment are needed in Central and Southern Maine as well as several new 115 kV lines in Mid-Coast, Western, and Downeast Maine. The MPRP is estimated to be the largest development project in CMP's history, costing approximately $1.5 billion.[76] However, MPRP is considered a regional investment and is eligible to be paid for by all the ratepayers in New England, not just those in Maine. Up to 92% of the costs could be paid by ratepayers from the other 5 New England states.[77]

Separately, CMP commissioned a study of non-transmission alternatives (NTAs), which could possibly eliminate or to delay the need to build new transmission lines. CMP's NTA assessment concluded that NTAs would not be sufficient to be alternatives to transmission lines and would generally

[76] Initial Filing of Petition for Finding of Public Convenience & Necessity for the Maine Power Reliability Program Consisting of the Construction of Approximately 350 miles of 345 kV and 115 kV Transmission Lines (MPRP). Maine Public Utilities Commission, Docket 2008-255 (July 1, 2008)

[77] Stephen Rourke, Vice President of System Planning, ISO-NE to David Conroy, Central Maine Power, Re: Request for Pool Supported PTF Cost Treatment for Maine Power Reliability Program; ISO-New England Written Findings and Determination. January 29, 2010.

be more expensive than building new transmission.[78] Some parties to the docket are contesting the findings of the study.

Non-Transmission Alternatives

In July 2008, CMP and Public Service of New Hampshire (PSNH) went to the Maine Public Utilities Commission (Commission) for approval of the MPRP and filed a Transmission Cost Allocation Application with ISO-NE. As proposed, the $1.5 billion MPRP consisted of approximately 350 miles of 115 kV and 345kV transmission lines and infrastructure intended to increase the capacity and transfer capability of Maine's transmission system and support the development of renewable energy resources in western and northern Maine and Canada.

Over the course of the next year, the Commission received and approved more than 180 petitions to intervene in the case, including petitions from the Office of Public Advocate (OPA), Industrial Energy Consumers Group (IECG), GridSolar LLC, Bangor Hydro, ENE (Environment Northeast), Conservation Law Foundation, Maine Renewable Energy Association, Maine State Chamber of Commerce, and ISO-NE. Many of the intervenors wanted to ensure that the ambitious MPRP would minimize both cost to ratepayers and environmental impact.[79]

In particular, GridSolar filed an alternative to the MPRP with the Commission that would meet Maine's reliability needs through the use of distributed solar generation in combination with small back-up generators and investments in a smart electric grid to promote energy efficiency and demand response. In their petition to the Commission, GridSolar argued that the development of up to 800 MW of distributed solar generation and the associated interconnection and reliability facilities could meet the state's reliability needs as well as the MPRP at lower cost, less financial risk to ratepayers, reduced land impact, and through the generation of zero-emission electricity.[80] In the initial and supplemental filings, GridSolar outlined the benefits of using distributed solar generation to meet Maine's energy needs instead of the MPRP:

- *GridSolar's proposal provides a level of reliability comparable to MPRP.* A combination of distributed solar generation and Smart Grid technology is shown to provide the same or better reliability than the MPRP. During peak hours, distributed solar generation is used to meet peak load rather than relying on traditional power supply from remote locations that must be delivered over the transmission system. By

[78] Non-Transmission Alternatives Assessment and Economic Evaluation of the Maine Power Reliability Program. Prepared by LaCapra Associates for Central Maine Power. Maine Public Utilities Commission, Docket 2008-255. June 30, 2008.

[79] *Updating the Electricity Grid: An Introduction to Non-Transmission Alternatives for Policymakers*. Prepared by the National Council on Electricity Policy. September 2009.

[80] *Petition by GridSolar, LLC.* , Docket No. 2008-255, Maine Public Utilities Commission (January 28. 2009).

reducing the strain on the transmission system, distributed solar generation will reduce the reliability impacts of peak load growth.

- *Incremental, distributed generation reduces the financial risk to ratepayers.* The forecasts for peak loads in the CMP service territory that were used as the basis for the MPRP proved to be over-estimated.[81] Revising the load forecasts to reflect actual peak loads in 2007 through 2009 showed that CMP's estimated peak load for 2017 would not be realized until 2029.[82] Lower load growth allows the MPRP upgrades to be delayed, saving ratepayers an estimated $200 million per year in carrying costs.[83] The benefit of the GridSolar project is that it can be developed incrementally, keeping in pace with peak load growth. This reduces the risk of building expensive transmission capacity that will never be fully utilized and burdening ratepayers with a stranded investment.

- *Incremental build-out minimizes costs to ratepayers.* By delaying the build-out of distributed generation until it is necessary to meet actual peak loads, GridSolar is able to take maximum advantage of the declining costs of solar generation, which are projected to fall over the next 10 years, and improved production efficiencies.

In their petition to the Commission, GridSolar requested that the Commission grant them status as a transmission and distribution utility and issue a Certificate of Public Convenience and Necessity to build 800 MW of distributed generation for the purpose of reducing load on the transmission grid during peak hours.

Around the same time, the Commission issued an order as part of Docket 2008-165, an on-going investigation into whether Maine's best interests are served by ISO-NE, directing the electric utilities that it regulates, Central Maine Power, Bangor Hydro-Electric, and Maine Public Service, to seek changes to its arrangements with ISO-NE. While the order found that participation in ISO-NE yielded considerable benefits, the Commission concluded that ISO-NE's cost-allocation methodology encourages over-reliance on transmission investments and lacks adequate barriers against transmission cost overruns for investments in regional transmission upgrades.[84] The Commission called for several specific reforms to be addressed in negotiations with ISO-NE, among them greater consideration of transmission alternatives when planning the regional system.

Resolution

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[81] *Id.*

[82] *Id.*

[83] *Id.*

[84] *Order,* Docket No. 2008-156, Maine Public Utilities Commission (June 30, 2009)

In June 2010, after over a year of settlement talks, the Commission approved a multi-party agreement in the MPRP proceeding.[85] The Stipulation introduces a blend of traditional transmission, distributed generation, smart grid technology, and increased investments in targeted energy efficiency.[86] The plan includes measures to reduce energy consumption, avoid greenhouse gas emissions from power generation, save ratepayers money and reduce the need for additional costly transmission expansions in the future. Specifically, the agreed upon plan will:

- Avoid new transmission lines in certain areas, substituting them with "smart grid" pilot projects to test the alternative use of distributed solar generation, and possibly other renewable resources, strategically distributed to provide peak power on a more localized basis.[87] The pilots will also facilitate increased adoption of plug-in electric vehicles and energy storage and address outstanding issues regarding smart grid such as ownership and cost recovery.

- Invest $17 million in low-income weatherization and targeted energy efficiency programs designed to reduce peak and off-peak energy use and lower the cost of transmission upgrades. The settlement also commits CMP and Bangor Hydro Electric to assist the Efficiency Maine Trust in developing triennial plans for state-wide energy efficiency programs.

- Establish a new stakeholder working group to consider and evaluate changes that would require ISO-NE employ least-cost transmission planning, consider NTAs as solutions to reliability problems, and evaluate regional cost "socialization" for NTAs. The plan includes $1.5 million to support consumer interests' advocacy in federal and regional forums on transmission planning and cost allocation matters.

Despite the Commission's expressed concern in Docket 2008-156 that ISO-NE regional system planning and cost allocation mechanisms promote an over-reliance on transmission investments, the Commission unanimously approved the settlement. The settlement includes the build-out of much of CMP's originally proposed expanded high-voltage transmission system at a cost estimate of $1.4 billion. Maine ratepayers will pay 8 percent of the total transmission project costs with the rest being shared by ratepayers throughout the region. This experience illustrates how cost socialization for transmission

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[85] *Stipulation*, Central Maine Power Company and Public Service of New Hampshire Request for Certificate of Public Convenience and Necessity for the Maine Power Reliability Program Consisting of the Construction of Approximately 350 Miles of 345 kV and 115 kV Transmission Lines. Maine Public Utilities Commission, Docket No. 2008-255. May 7, 2010. Note that ENE (Environment Northeast) was a party to the settlement.

[86] The settlement requires CMP to consider NTAs at an earlier state of the transmission planning process than previously required, and requires CMP to confer with certain consumer representatives.

[87] The settlement created two geographic areas in which a smart grid operator will be retained to implement systems designed to manage the local electrical system to minimize the need for transmission system upgrades. Such management will be enhanced by distributed generation, including PV solar generation. The smart grid operator will be selected in accordance with Maine Statute, 35-A MRSA Sec. 3143, and there is an ongoing Maine PUC proceeding to implement this smart grid approach, Maine PUC Docket No. 2010-267.

upgrades essentially precludes non-transmission alternatives from being used to meet electric system needs. Failure to provide cost socialization for non-transmission alternatives makes it nearly impossible for regulators, who must ensure reliable utility service while minimizing the economic impact on Maine ratepayers, to choose the non-transmission solution.

Overview

In January 2005, the Vermont Public Service Board (Board) approved Vermont Electric Company's (VELCO) Northwest Reliability Project, a major transmission upgrade to Vermont's transmission system originally estimated to cost $120 million. But, when the costs for the 345kV line from West Rutland to New Haven quickly ballooned to over $228 million[88,89], the Board questioned how thoroughly VELCO had examined NTAs. Opponents of the project argued that distributed generation and targeted efficiency could provide the same reliability at lower cost and an analysis of NTAs concluded that a combination of targeted energy efficiency and new generation could address the reliability need at 5.19% less than the cost of the transmission project.[90] However, due to deficiencies in the early consideration of non-transmission alternatives, the Board ultimately concluded that it had "no viable option but to approve a transmission solution for a reliability problem that might have been either deferred or more cost-effectively addressed through demand-side measures or local generation, if there had been sufficient advance planning by VELCO and its owners."[91] Although the alternative proposal for 74 MW of targeted efficiency had a lower expected total social cost, Vermont ratepayers would have to pay the total cost of the NTA, but only pay 7 percent of the transmission solution with the rest of the cost shared by ratepayers throughout New England. Also, due to the relatively slow pace at which the efficiency savings would build up, an additional 120 MW of generation would be needed, and it was unlikely that those generation resources would be built in time to address the reliability need.[92] The Board also identified an "efficiency gap" in which VELCO is relieved of its obligation to pursue cost-effective efficiency investments as long as they cooperate with Efficiency Vermont. However, Efficiency Vermont, because of a statutory cap on its funding, did not have the funding necessary to make all cost-effective energy efficiency investments. To avoid a repeat of this dilemma, the Board opened a separate investigation into ways to ensure that cost-effective NTAs are given full and timely consideration in the planning process.[93]

Around the same time that the Board opened its investigation, the Vermont Legislature passed Public Act 61, which set out the statutory basis for the state's transmission planning process- including

[88] Under the original estimate, the cost to Vermont ratepayers would have been approximately $12 million with the remainder paid for ratepayers in the other New England states. As costs rose, the Vermont's obligation rose to between $32 and $50 million

[89] Updating the Electric Grid: A Introduction to Non-Transmission Alternatives for Policymakers. Prepared by the National Council on Electricity Policy. September 2009.

[90] The Present Value of Total Societal Costs for the transmission proposal and the alternative proposal were $1,272,000,000 and $1,206,000,000, respectively.

[91] Order, Vermont Public Service Board, Docket No. 6860 (January 28, 2005).

[92] *Id.*

[93] *Id.*

the way in which Vermont would address NTAs. The Act required that VELCO develop a transmission plan jointly with other transmission owners and operators and with input from Efficiency Vermont, the state's energy efficiency program administrator, and the Vermont Department of Public Service. The law states: "[t]he objective of the plan shall be to identify the potential need for transmission system improvements as soon as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible."[94] Act 61 also requires the distribution utilities to incorporate the transmission system plan into their own integrated resource plans. The Board determined that the provisions of Act 61 address some, but not all, of the issues regarding least-cost planning for Vermont's transmission system that were identified throughout the Northwest Reliability Project deliberations.[95]

Memorandum of Understanding

The Board's concerns about lack of attention to NTAs eventually resulted in a Memorandum of Understanding (MOU) signed in September 2006 that established a process through which transmission planning would incorporate- from its early stages- consideration of NTAs. Signed by some, but not all, of the stakeholders, the MOU defined a process for least cost transmission planning over a 20 year time horizon and created a Vermont System Planning Committee (VSPC) with the charge of independently reviewing transmission plans and screening for NTAs[96]. The MOU described a process for:

- identifying reliability deficiencies;
- determining performance specifications that NTAs will need to meet to be considered equivalent to the transmission option for resolving the deficiency;
- identifying and analyzing possibly non-transmission alternatives;
- obtaining public input; and,
- selecting a solution to the reliability deficiency.[97]

[94] Vermont Public Act 61 (2005). An Act Relating to Renewable Energy, Efficiency, Transmission, and Vermont's Energy Future. Sec. 9 30 V.S.A. § 218c Least Cost Integrated Planning.

[95] Vermont Public Service Board, Final Order Docket 7081, Investigation into Least Cost Integrated Resource Planning for Vermont Electric Company's, Inc. Transmission System. June 20, 2007.

[96] The members of the VSPC include: representatives of each Vermont electric distribution and transmission utility; and three public members representing the interests of residential consumers, commercial and industrial consumers, and environmental protection respectively. In addition, three non-voting members participate in the VSPC, including Efficiency Vermont, the Sustainably Priced Energy Enterprise Development Facilitator, and the Vermont Department of Public Service

[97] Vermont Public Service Board, Final Order Docket 7081, Investigation into Least Cost Integrated Resource Planning for Vermont Electric Company's, Inc. Transmission System. June 20, 2007.

Among the stakeholders opposed to the MOU the chief concern was that the MOU did not do enough to protect the environment or ensure that NTAs would be given priority status in transmission planning.[98] Key stakeholders contended that the MOU limits public input in the transmission planning process; weakens standards for evaluating projects; and, fails to treat NTAs equivalent to transmission solutions for funding. [99]

Status

The VSPC began operation in 2007 and the first full planning cycle under the MOU commenced in February 2010. VSPC reviewed and provided comments on VELCO's draft 2009 Vermont Long-Range Transmission Plan and has done an assessment of the potential for NTAs within that plan but has not identified any potential or cost-effective NTAs as substitutes for transmission upgrades. One of the VSPC's successes in Vermont has been the integration of Efficiency Vermont- the state's energy efficiency program administrator that is charged with carrying out all energy efficiency programs- into the long-term planning process.

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98 *Id.*

99 *Id.*

Case Study: Marshfield, Massachusetts

Overview

In 2007, NSTAR and the Massachusetts Technology Collaborative embarked on a $4 million, 18-month, community-focused pilot project to determine whether energy efficiency, clean distributed generation, and demand response could freeze peak demand growth and defer or offset distribution system upgrades.[100] Marshfield, MA was selected for the pilot, in part, because successful and sufficient load reduction in Marshfield could defer a distribution system upgrade that would otherwise be required to meet peak load. Summer peak was forecast to exceed the capacity of the existing system, but a targeted load reduction of 2 MW could defer (or possibly offset) the need for line upgrades. Of these 2 MW, a 1 MW reduction could be achieved by installing a biodiesel generator at a local substation, which would only operate during summer peak conditions. The other 1 MW of load reduction would come from distributed resources, including energy efficiency, demand response, and distributed photovoltaic power located at homes and businesses. To defer the necessary upgrade, at least 500 kW had to be achieved by the summer of 2008, and at least an additional 500 kW reduction had to be achieved by the summer of 2009. Deferring the upgrade would benefit NSTAR electric ratepayers. Absent the load reduction, upgrades to the overhead distribution circuits as well as to the distribution substation would occur in 2009 and 2010 and the total cost of the upgrade was estimated to be approximately $2,650,000. If the upgrades are deferred one year, the reduction in the present value revenue requirement to customers is approximately $150,000 ($25.65/kW-yr). Deferring the upgrades for four years reduces the present value revenue requirement by over $716,000 ($35.65/kW-yr.). The value of deferral was used to estimate the maximum incentive levels that could be justified because payments in excess of that amount for distribution deferral are uneconomic.[101]

Energy Efficiency, Distributed Generation, and Demand Response

The distinguishing feature of the Marshfield Energy Challenge is that efficiency, demand response (DR), and distributed generation (DG) were a bundled offering to customers. The objective was to reduce peak load by 1 MW though a combination of savings from targeted energy efficiency (300 kW), direct load control (580 kW) and photovoltaic systems (120 kW). To achieve these savings levels, NSTAR simplified the offer so that one audit integrated NSTAR programs for lighting, refrigerators, air sealing and insulation, thermostats, and an HVAC tune-up. The audit featured the replacement of incandescent bulbs with CFLs, a $150 rebate for a high efficiency refrigerator if the current refrigerator qualified, the offer of no-cost air sealing and insulation services, a programmable smart thermostat, and a

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[100] The grant budget for expenditures on program marketing and incentives for distributed energy resources (not including program design, measurement and evaluation, and other costs) was $2.14 million, which was matched by NSTAR.

[101] Note that the values cited only include the benefits of distribution deferral, and does not include any benefits from the ISO-NE Forward Capacity Market, energy savings, environmental benefits, or other value streams that could be attributable to energy efficiency, distributed resources, and renewable energy.

free HVAC equipment tune-up for qualified homeowners. Customers were also offered significant incentives for photovoltaic panels, up to $1,000 rebate for high efficiency heating systems, $300 rebate for a high efficiency hot water heater, and rebates on EnergyStar ™ replacement windows.

The average home or business owner was estimated to save 1,500 kWh from the lighting and refrigerator upgrades and 350 therms from the weatherization services.

NSTAR performed free energy audits on 1,138 homes in Marshfield with subsequent installation of energy efficiency measures such as insulation and efficiency appliances, especially air conditioners. In addition, NSTAR installed 500 smart thermostats that allowed customers greater control over their energy use and gave NSTAR the ability to raise household temperatures up to 4 degrees on hot summer days of peak demand. Finally, 33 homes had subsidized photovoltaic systems installed. The total cost of the Marshfield Energy Challenge was $4,460,843 or $1.80 per kWh saved (see Table below).

Outcome

Participation in NSTAR's energy efficiency programs within Marshfield jumped from 50 to 650 (1,300 percent increase) in the first 9 months of the pilot. The Challenge reduced the town's peak electricity demand by over 1.2 MW and the pressure on the affected circuit was sufficiently reduced. Two-thirds of this reduction was from the residential sector. Almost 1,300 homeowners receiving energy audits and 90 percent installed at least one energy efficiency light bulb. Between 10 and 20 percent installed insulation, air sealing, or other heating measures, or completed an air conditioner tune-up and 32 (2.5 percent) residential customers installed solar panels for a total of over 263 kW of solar generation. Final evaluation of the total cost of the pilot, deferral value of the delayed distribution upgrade, and additional efficiency benefits have yet to be made public, but the Marshfield Energy Challenge has demonstrated that a combination of targeted energy efficiency and distributed generation can defer distribution system upgrades. However, Massachusetts still faces barriers to fully integrating non-wires alternatives into the state's distribution system and should support rule changes at the MA Department of Public Utilities and ISO-NE that require consideration of non-wires solutions to electric system needs and clarify cost support for non-wires solutions to both distribution and transmission needs.

Overview

The Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006[102] identified a unique opportunity for Rhode Island to systematically identify and procure customer-side opportunities (targeted energy efficiency, demand response, and distributed generation, including renewables and combined heat and power) that are not only cost-effective compared to traditional supply options, but that might also provide a cost-effective path to lower supply and delivery costs to ratepayers in Rhode Island. If distribution or transmission system investments could be deferred, then the program might provide savings over time for customers and might lower the volatility and cost uncertainty of the larger energy and capacity markets in New England by securing sources of energy supply and capacity from in-state resources.

The 2006 law directs National Grid, Rhode Island's primary distribution company, to propose pilot distribution and, if appropriate, transmission projects in a "system reliability procurement plan" that examines customer-side resources as alternatives or enhancements to an anticipated distribution or transmission upgrade. The system reliability resources to be examined in the plan include distributed generation generally; combined heat and power; renewable resources (predominately wind and solar); demand response; and peak demand and geographically targeted energy efficiency programs.

The law also directs the utility to identify an evaluation process for proposed pilot projects that allows for stakeholder input and includes information such as the following:

- Description of the transmission or distribution solution, including the anticipated cost and timeline for the project;
- Description of the need, requirements, and drivers of the problem such as demand growth;
- Identification of the level of peak demand savings or energy demand reduction required to avoid the need for the upgrade;
- Development of alternative solutions that utilize customer-side resources, including ownership and contracting considerations, a detailed cost estimate, and implementation schedule;
- Comparison of the traditional and alternative solutions from a cost-perspective, with cost assessed on a net present value basis to the state's ratepayers;
- Summary of the anticipated environmental impacts and a discussion of any co-benefits of the alternatives solution, such as benefits to local businesses or industry; and,
- Recommendation for the preferred solution.

In 2008, National Grid filed a proposal with the Rhode Island Public Utilities Commission (PUC or Commission) for a community-focused pilot project in southern Rhode Island aimed at deferring the

[102] R.I.G.L. § 39-1-27.7 (2006)

need to upgrade a local substation through the use of demand response and small-scale wind and solar resources.[103] Intervenors, including the Division of Public Utilities and Carriers, urged the Commission not to approve the pilot project unless the utility established a process to assess the cost-effectiveness of the customer-side resource solution as compared to the substation upgrade.[104]

Stakeholder Engagement

For 18 months beginning in September 2009, National Grid has collaborated with members of the state's Energy Efficiency and Resource Management Council (EERMC), a ratepayer council representing residential, low-income, business, industrial, and environmental interests, to develop a process for revising the system reliability procurement standards and a framework for considering NWAs as possible solutions to planning and reliability issues. The Council's objective is to establish a procedure and funding options for systematically identifying customer-side and distributed resources that, if cost-effective, defer or avoid distribution upgrades, improve system reliability, and provide for better utilization of distributed resources. The goal is also to effectively anticipate new technologies (such as electric vehicles and energy storage) and become a model for other states and utilities.

On March 1, 2011, the EERMC proposed revisions to the System Reliability Procurement Standards with the intent of providing clear guidelines for a planning process that considers both traditional and non-wires alternatives to planning and reliability issues. The recommendations for revising the System Reliability Procurement Standards are designed to guide National Grid in fully integrating analysis of non-wires alternatives into National Grid's planning functions and evaluating the specific costs, benefits, and comparability of traditional and non-wires solutions. The proposed revisions outline a process in which National Grid and the Council will work with state regulators and other stakeholders to further the collective understanding of non-wires alternatives. This will include the development of more sophisticated analytical tools, development of appropriate evaluation criteria, and potentially, proposing demonstration project installations of cost-effective non-wires alternative solutions. The revisions to the Standards establish a process that enables an objective assessment of the alternatives as the Company integrates the analysis of non-wires alternatives into distribution planning, as required by R.I.G.L. § 39-1-27.7. The recommendations were approved by the Rhode Island Public Utilities Commission on June 7, 2011.

National Grid has also undergone a lengthy and comprehensive internal planning process to incorporate the consideration of NWA options into its Distribution and Transmission planning. This procedure has been signed approved by National Grid on February 8, 2011 for its own use by the Vice Presidents of Transmission Asset Management, Distribution Asset Strategy and Policy, Energy Products, and Smart Grid . The company also initiated the development of an analytical tool that compares the total, net, and avoided costs of customer-side solutions relative to transmission and distribution investments, allowing choices to be made based on what is the most cost-effective alternative. Costs and

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[103] National Grid. 2009-2011 Energy Efficiency and System Reliability Procurement Plan.

[104] Rhode Island Division of Public Utilities, Position on National Grid's System Reliability Procurement Plan. December 22, 2009.

benefits to be assessed include, but are not limited to: capital costs, operation and maintenance, fuel costs, energy savings, and peak demand savings.

Challenges

One significant challenge to system reliability planning and procurement is that the utility is able to recover the cost of, and earn a rate of return on, investments in distribution infrastructure, but is not able to recover the cost of investments in customer-side alternatives like demand response or distributed generation. So long as there is no cost-recovery mechanism for "non-wires" alternatives, the table will always tilt toward traditional "poles and wires" solutions. The System Reliability Procurement Subcommittee is working with the utility and other key stakeholders to propose policies and regulatory changes to address these issues and identify sustainable payment mechanisms that allow non-wires alternatives to be considered on an equal footing with traditional distribution upgrades. As part of this process, the Subcommittee will be reviewing Rhode Island's regulatory framework to ensure that unnecessary barriers to deployment of non-wires alternatives are removed. Achieving a similar process at the transmission level, however, will require regulatory changes to the ISO-NE Open Access Transmission Tariff and the Regional System Planning process.

The adoption of the State policy of "System Reliability" planning enunciated in the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006 illustrates that Rhode Island has embraced the incorporation of non-wires alternatives into distribution planning. In order to fully integrate non-wires alternatives into the region's transmission system, Rhode Island should support ISO-NE rule changes that require consideration of non-transmission solutions to electric system needs and provide regional cost support for non-transmission solutions.

Appendix F

Case Study: New York Independent System Operator, Comprehensive Reliability Planning Process

Overview

The New York ISO (NYISO) Comprehensive Reliability Planning Process (CRPP), as approved by FERC in December, 2004 and contained in Attachment Y of NYISO's OATT, is the primary tool used by NYISO to identify and resolve reliability needs in the New York Control Area (NYCA).[105] The CRPP is unique because it evaluates generation, transmission, and demand response solutions to an indentified system reliability need on a comparable basis and gives preference to market-based solutions. The CRPP is conducted in a multi-step process, anchored in the NYISO market-based philosophy that "market solutions should be the first choice to meet identified reliability needs."[106] In the first step, NYISO identifies long-term (10-year) reliability needs based on existing reliability criteria, including North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and New York State Reliability Council (NYSRC) standards. In preparing the Reliability Needs Assessment (RNA), NYISO develops "reliability scenarios" based on assumptions of load forecasts, fuel prices and availability, new resources, retirements, and proposed environmental legislation, among other factors, and identifies violations of reliability criteria given changes in these assumptions. If any reliability criteria are not met in any future year, NYISO analyzes whether additional resources and/or transmission expansion is needed to meet the requirements and determines the first year of need for those additional resources or transmission (the RNA does not identify specific facilities, however).

Following review by NYISO committees and final approval from the NYISO Board, NYISO requests solutions from the market place to the identified reliability needs. The RNA also identifies the "Responsible Transmission Owner (s)" that is obligated to prepare regulated backstop solutions for each identified need. The regulated backstop solution also serves as a benchmark to establish the time frame for a market-based solution to appear. Both market-based and regulated solutions are open to all resources: generation, transmission, and demand response.

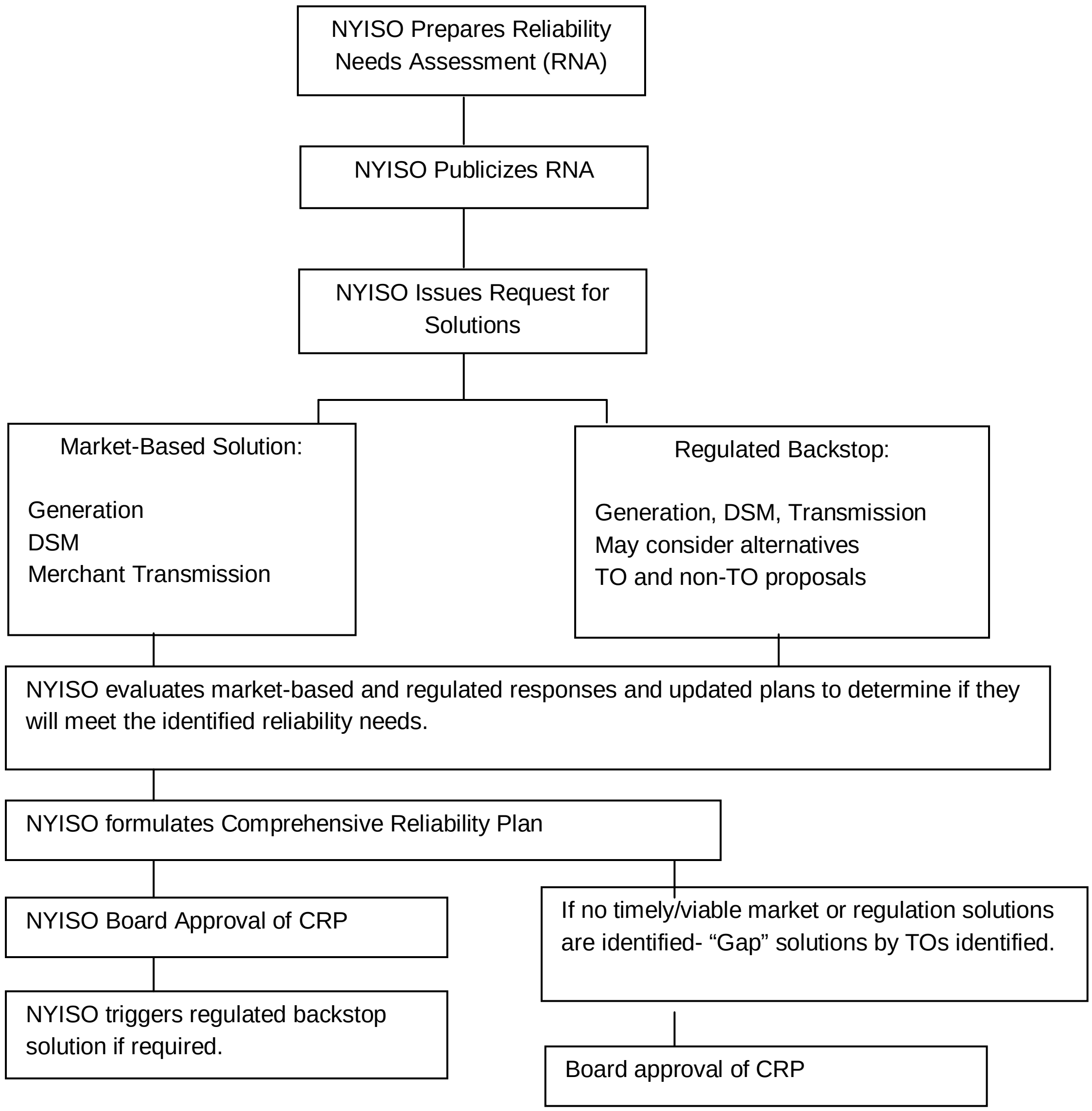
NYISO evaluates all of the proposed solutions to determine whether they are viable and will meet the identified need in a timely manner. Following its evaluation of all of the proposed solutions, NYISO prepares the CRPP. The CRPP identifies all proposed solutions that NYISO has found to meet part or all of the identified need. If a market-based solution has been proposed, the CRPP will state so. If not, NYISO determines whether a regulated backstop solution is needed and will request that the Responsible TO(s) proceed with regulatory approval and development of the backstop solution.

[105] New York Independent System Operator, Inc. FERC Electric Tariff Attachment Y: NYISO Comprehensive Planning Process for Reliability Needs.

[106] New York Independent System Operator, Inc. Comprehensive Reliability Planning Process Manual. November 20, 2007.

. If NYISO determines that neither the market-based proposals nor the "backstop" regulated solution can address the reliability need in a timely manner, NYISO can designate a transmission owner(s) to develop a "gap solution," provided that the temporary fix does not create an economic barrier for a future, market-based solution.[107]

Figure: NYISO Reliability Planning Process Diagram[108]



2008 Comprehensive Reliability Plan

[107] John Buechler, NYISO Comprehensive Planning Process for Reliability Needs, Presentation. Washington, D.C. July 16, 2008.

[108] New York Independent System Operator, Inc. . Comprehensive Reliability Planning Process Manual. November 20, 2007.

The 2008 RNA identified a reliability need in 2012 due to a statewide capacity deficiency and a local transmission constraint. The need could be resolved by adding capacity resources downstream of the transmission constraints or by adding resources upstream of transmission constraints in conjunction with transmission reinforcements. Accordingly, NYISO designated all transmission owners to identify a regulated backstop solution to the reliability need and solicited proposals for market-based projects (the preferred solution). NYISO received over 3,800 MW of market-based solutions: 2,430 MW of non-transmission solutions (including 425 MW of demand response) and 1,510 MW of new transmission capacity,[109] together representing sufficient solutions to defer the initial 2,350 MW reliability need to 2013 with the incorporation of an updated transmission owner plan to deliver firm capacity to New York via a market-based high-voltage DC transmission project connecting Long Island to PJM[110].

Cost Allocation and Cost Recovery

While market-based solutions are preferred, if a regulated backstop solution is needed it is paid for on a "beneficiary pays" basis, which was developed by NYISO and its stakeholders through the Electric System Planning Working Group (ESPWG), pursuant to FERC Order 890.[111] FERC subsequently approved this cost allocation methodology as revisions to Attachment Y and Schedule 10 of the NYISO OATT.[112] Under the beneficiary pays principle, regions or zones identified as contributing to the reliability violation are responsible for the costs of the solution and costs are allocated to those zones based on their contribution to the violation and to the load serving entities within each zone based on their share of the load (MWh) [113, 114, 115].

In December 2007, the New York Public Service Commission (PSC) initiated Case 07-E-1507, Order Initiating Electricity Reliability and Infrastructure Planning, in order to address cost allocation and recovery for regulated non-transmission projects that may be required if market-based projects are not sufficient to address the reliability needs and NYISO triggers a regulated backstop solution. In April 2008, after soliciting input on possible cost allocation methodologies from stakeholders, NYISO issued a

[109] NYISO, News Release: NYISO Issues 2008 Comprehensive Reliability Plan. July 15, 2008.

[110] NYISO White Paper. Transmission Expansion in New York State. November 2008.

[111] The "beneficiary pays" cost allocation only applies to regulated backstop solutions, it does not apply to market-based solutions. Developers of market-based solutions are expected to recover their costs from NYISO's energy, capacity, and ancillary services markets. Developers may also obtain revenues from other private contracting agreements.

[112] Cost allocation for reliability solutions applies to transmission as governed by Attachment Y of the NYISO OATT- Section 31,4,2,2, on page 60.

[113] NYISO White Paper. Transmission Expansion in New York State. November 2008.

[114] Sari Fink, Jennifer Rogers, and Kevin Porter. Transmission Cost Allocation Methodologies for Regional Transmission Organizations. National Renewable Energy Laboratories. July 2010.

[115] Discussion with Carl Patka and Joe Buechler, NYISO, April 6, 2011.

policy statement on non-transmission project cost-allocation. In the statement, the PSC stated its preference that:

> …in addressing cost allocation issues, New York's allocation of non-transmission reliability backstop project costs should be compatible with FERC's allocation of transmission costs to avoid having projects judged or adopted based on a preferred regulatory cost allocation mechanism. In other words, the choice of the best regulated backstop project to fulfill a reliability need should not be biased by any material difference between state and federal approaches to cost recovery and allocation.[116]

In the Order, the PSC adopted the beneficiaries-pay principle developed by the NYISO ESPWG for regulated non-transmission projects, consistent with the cost allocation methodology for regulated transmission projects. As such, the calculation of the cost allocation for non-transmission backstop solutions is performed by NYISO, and the results are provided to the PSC.

Conclusion

NYISO's reliability planning process is fundamentally different from ISO-NE. The NYISO CRPP looks at all resources- generation, transmission, and demand response- for solutions, and places a much higher reliance on market-based solutions for reliability needs. In response to recent CRPPs, market-based solutions have been proposed and are being developed to fully meet reliability needs identified through 2013. The CRPP's "resource-neutral" nature, its preference for market-based solutions, and similar cost allocation methodologies for transmission and non-transmission solutions make it less likely that transmission will be chosen as a solution to address reliability needs in New York. However, despite the efforts of NYISO and the PSC to provide equal consideration to generation, transmission, and demand response, only transmission solutions are eligible for return on equity as set by FERC. NTAs are not eligible for any return on equity.[117] The New York model may provide an important example to New England policy makers and stakeholders who are considering how to incorporate NTAs into the planning and cost allocation mechanisms.

[116] Case 07-E-1507, Proceeding to Establish a Long-Range Electric Resource Plan and Infrastructure Planning Process. Policy Statement on Backstop Project Cost Recovery and Allocation. New York State Public Service Comission. April 24, 2008.

[117] Discussion with Carl Patka and Joe Buechler, NYISO, April 6, 2011.

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